PUNA
GEOTHERMAL
VENTURE
An ORMAT Company

November 7, 2019

Mr. David Albright
U.S. Environmental Protection Agency
Ground Water Office (WTR-9)
75 Hawthorne Street
San Francisco, CA 94105

Dear Mr. Albright:

Pursuant to the Environmental Protection Agency (EPA) Permit No. HI596002, Puna Geothermal Venture (PGV) is pleased to re-submit the Underground Injection Control (UIC) Permit Renewal Application. PGV is very committed to continue working with EPA to maintain a mutually agreeable UIC permit.

If you have any questions regarding the application or require additional information, please do not hesitate to contact me at 808-896-8551.

Respectfully,

Jordan Hara
Plant Manager

Enclosure: Renewal, Underground Injection Control Permit Application No. HI 596002
Attachments A through V.

CC: Ms. Michele Dermer

PUNA GEOTHERMAL VENTURE
14-3860 Kapoho Pahoa Road, Pahoa, HI 96778-0030, USA • +1-808-965-6233 • ormat@ormat.com
ormat.com

PUNA GEOTHERMAL VENTURE STANDARD OPERATING PROCEDURE

ORMAT

Title: **PGV Geothermal Well Distinction**	Procedure:	Revision: **0**	Page **1** of **1**
	Plant Manager: Jordan Hara		Signature:

Location:

The general location of production and injection is based on the geological model and numerical reservoir modeling to optimize long term operation of the field.

System Description:

Production Well

A well may be used for production if:

- The well is productive, i.e. has sufficient permeability, temperature and pressure for production.
- The production zone is far enough away from injection so thermal breakthrough will not occur too quickly.

Department of Land and Natural Resources (DLNR) will oversee and regulate, in accordance with Chapter 13-183 and 13-184, HAR, the permitting, drilling, construction, testing, modification, production and abandonment of all exploration, monitoring and production geothermal wells per PGV Plan of Operations (POO) permit requirements.

Injection Well

A well may be used for injection if:

- The well is not productive, or low productivity so it is better used for injection.
- The injection zone is far enough away from production so thermal breakthrough will not occur too quickly.
- The injection zone can be connected to production if pressure support is needed.

Environmental Protection Agency (EPA) Region 9 #HI596002 and the Hawaii State Department of Health (HDOH) #UH-1529 will oversee and regulate the permitting, testing and operation of all designated geothermal injection wells per PGV Underground Injection Control (UIC) permit requirements.

OMB No. 2040-0042 Approval Expires 1/31/05

EPA

United States Environmental Protection Agency

Underground Injection Control Permit Application

(Collected under the authority of the Safe Drinking Water Act. Sections 1421, 1422, 40 CFR 144)

I. EPA ID Number		T/A	C
U			

Read Attached Instructions Before Starting

For Official Use Only

Application approved (mo day year)	Date received (mo day year)	Permit Number	Well ID	FINDS Number

II. Owner Name and Address

Owner Name: Puna Geothermal Venture

Street Address: 14-3860 Kapoho-Pahoa Road / P.O. Box 30

Phone Number: (808) 965-6233

City: Pahoa | State: HI | ZIP CODE: 96778

III. Operator Name and Address

Owner Name: Puna Geothermal Venture

Street Address: 14-3860 Kapoho-Pahoa Road / P.O. Box 30

Phone Number: (808) 965-6233

City: Pahoa | State: HI | ZIP CODE: 96778

IV. Commercial Facility	V. Ownership	VI. Legal Contact	VII. SIC Codes
[x] Yes [ ] No	[x] Private [ ] Federal [ ] Other	[x] Owner [ ] Operator	4911 1781 See Footnote *1 1381

VIII. Well Status *(Mark "x")*

[ ] A. Operating — Date Started (mo day year):

[ ] B. Modification/Conversion

[ ] C. Proposed

IX. Type of Permit Requested *(Mark "x" and specify if required)*

[x] A. Individual [ ] B. Area	Number of Existing Wells	Number of Proposed Wells	Name(s) of field(s) or project(s)
	5 See Footnote *2	11 See Footnote *2	Kapoho Field in the Kilauea Lower East Rift Geothermal Resource Subzone

X. Class and Type of Well *(see reverse)*

A. Class(es) (enter code(s))	B. Type(s) (enter code(s))	C. If class is "other" or type is code 'x,' explain	D. Number of wells per type (if area permit)
5	3T	Injection wells for fluids associated with the production of geothermal energy.	

XI. Location of Well(s) or Approximate Center of Field or Project See Footnote *3

Latitude Deg	Latitude Min	Latitude Sec	Longitude Deg	Longitude Min	Longitude Sec	Sec	Twp	Range	1/4 Sec	Feet From	Line	Feet From	Line
19°	28'	49"N	154°	53'	35"W								

XII. Indian Lands (Mark 'x')

[ ] Yes

[x] No

XIII. Attachments

(Complete the following questions on a separate sheet(s) and number accordingly; see instructions)

For Classes I, II, III, (and other classes) complete and submit on a separate sheet(s) Attachments A--U (pp 2-6) as appropriate. Attach maps where required. List attachments by letter which are applicable and are included with your application.

XIV. Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

A. Name and Title *(Type or Print)*: Jordan Hara, Plant Manager

B. Phone No. *(Area Code and No.)*: (808) 896-8551

C. Signature: Jordan Hara

D. Date Signed: 12-20-2019

Well Class and Type Codes

Class I		Wells used to inject waste below the deepest underground source of drinking water.
Type	**"I"**	Nonhazardous industrial disposal well
	"M"	Nonhazardous municipal disposal well
	"W"	Hazardous waste disposal well injecting below USDWs
	"X"	Other Class I wells (not included in Type "I," "M," or "W")
Class II		Oil and gas production and storage related injection wells.
Type	**"D"**	Produced fluid disposal well
	"R"	Enhanced recovery well
	"H"	Hydrocarbon storage well (excluding natural gas)
	"X"	Other Class II wells (not included in Type "D," "R," or "H")
Class III		Special process injection wells.
Type	**"G"**	Solution mining well
	"S"	Sulfur mining well by Frasch process
	"U"	Uranium mining well (excluding solution mining of conventional mines)
	"X"	Other Class III wells (not included in Type "G," "S," or "U")
Other Classes		Wells not included in classes above. Class V wells which may be permitted under §144.12. Wells not currently classified as Class I, II, III, or V.

Attachments to Permit Application

Class	**Attachments**
I new well	A, B, C, D, F, H – S, U
existing	A, B, C, D, F, H – U
II new well	A, B, C, E, G, H, M, Q, R; optional – I, J, K, O, P, U
existing	A, E, G, H, M, Q, R, – U; optional – J, K, O, P, Q
III new well	A, B, C, D, F, H, I, J, K, M – S, U
existing	A, B, C, D, F, H, J, K, M – U
Other Classes	To be specified by the permitting authority

INSTRUCTIONS - Underground Injection Control (UIC) Permit Application

Paperwork Reduction Act: The public reporting and record keeping burden for this collection of information is estimated to average 394 hours for a Class I hazardous well application, 252 hours for a Class I non-hazardous well application, 32 hours for a Class II well application, and 119 hours for a Class III well application. Burden means the total time, effort, or financial resource expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal Agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to the collection of information; search data sources; complete and review the collection of information; and, transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques to Director, Collection Strategies Division, U.S. Environmental Protection Agency (2822), 1200 Pennsylvania Ave., NW., Washington, DC 20460. Include the OMB control number in any correspondence. Do not send the completed forms to this address.

This form must be completed by all owners or operators of Class I, II, and III injection wells and others who may be directed to apply for permit by the Director.

I. **EPA I.D. NUMBER** - Fill in your EPA Identification Number. If you do not have a number, leave blank.

II. **OWNER NAME AND ADDRESS** - Name of well, well field or company and address.

III. **OPERATOR NAME AND ADDRESS** - Name and address of operator of well or well field.

IV. **COMMERCIAL FACILITY** - Mark the appropriate box to indicate the type of facility.

V. **OWNERSHIP** - Mark the appropriate box to indicate the type of ownership.

VI. **LEGAL CONTACT** - Mark the appropriate box.

VII. **SIC CODES** - List at least one and no more than four Standard Industrial Classification (SIC) Codes that best describe the nature of the business in order of priority.

VIII. **WELL STATUS** - Mark Box A if the well(s) were operating as injection wells on the effective date of the UIC Program for the State. Mark Box B if wells(s) existed on the effective date of the UIC Program for the State but were not utilized for injection. Box C should be marked if the application is for an underground injection project not constructed or not completed by the effective date of the UIC Program for the State.

IX. **TYPE OF PERMIT** - Mark "Individual" or "Area" to indicate the type of permit desired. Note that area permits are at the discretion of the Director and that wells covered by an area permit must be at one site, under the control of one person and do not inject hazardous waste. If an area permit is requested the number of wells to be included in the permit must be specified and the wells described and identified by location. If the area has a commonly used name, such as the "Jay Field," submit the name in the space provided. In the case of a project or field which crosses State lines, it may be possible to consider an area permit if EPA has jurisdiction in both States. Each such case will be considered individually, if the owner/operator elects to seek an area permit.

X. **CLASS AND TYPE OF WELL** - Enter in these two positions the Class and type of injection well for which a permit is requested. Use the most pertinent code selected from the list on the reverse side of the application. When selecting type X please explain in the space provided.

XI. **LOCATION OF WELL** - Enter the latitude and longitude of the existing or proposed well expressed in degrees, minutes, and seconds or the location by township, and range, and section, as required by 40 CFR Part 146. If an area permit is being requested, give the latitude and longitude of the approximate center of the area.

XII. **INDIAN LANDS** - Place an "X" in the box if any part of the facility is located on Indian lands.

XIII. **ATTACHMENTS** - Note that information requirements vary depending on the injection well class and status. Attachments for Class I, II, III are described on pages 4 and 5 of this document and listed by Class on page 2. Place EPA ID number in the upper right hand corner of each page of the Attachments.

XIV. **CERTIFICATION** - All permit applications (except Class II) must be signed by a responsible corporate officer for a corporation, by a general partner for a partnership, by the proprietor of a sole proprietorship, and by a principal executive or ranking elected official for a public agency. For Class II, the person described above should sign, or a representative duly authorized in writing.

INSTRUCTIONS - Attachments

Attachments to be submitted with permit application for Class I, II, III and other wells.

A. **AREA OF REVIEW METHODS** - Give the methods and, if appropriate, the calculations used to determine the size of the area of review (fixed radius or equation). The area of review shall be a fixed radius of 1/4 mile from the well bore unless the use of an equation is approved in advance by the Director.

B. **MAPS OF WELL/AREA AND AREA OF REVIEW** - Submit a topographic map, extending one mile beyond the property boundaries, showing the injection well(s) or project area for which a permit is sought and the applicable area of review. The map must show all intake and discharge structures and all hazardous waste treatment, storage, or disposal facilities. If the application is for an area permit, the map should show the distribution manifold (if applicable) applying injection fluid to all wells in the area, including all system monitoring points. Within the area of review, the map must show the following:

Class I

The number, or name, and location of all producing wells, injection wells, abandoned wells, dryholes, surface bodies of water, springs, mines (surface and subsurface), quarries, and other pertinent surface features, including residences and roads, and faults, if known or suspected. In addition, the map must identify those wells, springs, other surface water bodies, and drinking water wells located within one quarter mile of the facility property boundary. Only information of public record is required to be included in this map;

Class II

In addition to requirements for Class I, include pertinent information known to the applicant. This requirement does not apply to existing Class II wells;

Class III

In addition to requirements for Class I, include public water systems and pertinent information known to the applicant.

C. **CORRECTIVE ACTION PLAN AND WELL DATA** - Submit a tabulation of data reasonably available from public records or otherwise known to the applicant on all wells within the area of review, including those on the map required in B, which penetrate the proposed injection zone. Such data shall include the following:

Class I

A description of each well's types, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require. In the case of new injection wells, include the corrective action proposed to be taken by the applicant under 40 CFR 144.55.

Class II

In addition to requirement for Class I, in the case of Class II wells operating over the fracture pressure of the injection formation, all known wells within the area of review which penetrate formations affected by the increase in pressure. This requirement does not apply to existing Class II wells.

Class III

In addition to requirements for Class I, the corrective action proposed under 40 CFR 144.55 for all Class III wells.

D. **MAPS AND CROSS SECTION OF USDWs** - Submit maps and cross sections indicating the vertical limits of all underground sources of drinking water within the area of review (both vertical and lateral limits for Class I), their position relative to the injection formation and the direction of water movement, where known, in every underground source of drinking water which may be affected by the proposed injection. (Does not apply to Class II wells.)

E. **NAME AND DEPTH OF USDWs (CLASS II)** - For Class II wells, submit geologic name, and depth to bottom of all underground sources of drinking water which may be affected by the injection.

F. **MAPS AND CROSS SECTIONS OF GEOLOGIC STRUCTURE OF AREA** - Submit maps and cross sections detailing the geologic structure of the local area (including the lithology of injection and confining intervals) and generalized maps and cross sections illustrating the regional geologic setting. (Does not apply to Class II wells.)

G. **GEOLOGICAL DATA ON INJECTION AND CONFINING ZONES (Class II)** - For Class II wells, submit appropriate geological data on the injection zone and confining zones including lithologic description, geological name, thickness, depth and fracture pressure.

H. **OPERATING DATA** - Submit the following proposed operating data for each well (including all those to be covered by area permits): (1) average and maximum daily rate and volume of the fluids to be injected; (2) average and maximum injection pressure; (3) nature of annulus fluid; (4) for Class I wells, source and analysis of the chemical, physical, radiological and biological characteristics, including density and corrosiveness, of injection fluids; (5) for Class II wells, source and analysis of the physical and chemical characteristics of the injection fluid; (6) for Class III wells, a qualitative analysis and ranges in concentrations of all constituents of injected fluids. If the information is proprietary, maximum concentrations only may be submitted, but all records must be retained.

I. **FORMATION TESTING PROGRAM** - Describe the proposed formation testing program. For Class I wells the program must be designed to obtain data on fluid pressure, temperature, fracture pressure, other physical, chemical, and radiological characteristics of the injection matrix and physical and chemical characteristics of the formation fluids.

For Class II wells the testing program must be designed to obtain data on fluid pressure, estimated fracture pressure, physical and chemical characteristics of the injection zone. (Does not apply to existing Class II wells or projects.)

For Class III wells the testing must be designed to obtain data on fluid pressure, fracture pressure, and physical and chemical characteristics of the formation fluids if the formation is naturally water bearing. Only fracture pressure is required if the program formation is not water bearing. (Does not apply to existing Class III wells or projects.)

J. **STIMULATION PROGRAM** - Outline any proposed stimulation program.

K. **INJECTION PROCEDURES** - Describe the proposed injection procedures including pump, surge, tank, etc.

L. **CONSTRUCTION PROCEDURES** - Discuss the construction procedures (according to §146.12 for Class I, §146.22 for Class II, and §146.32 for Class III) to be utilized. This should include details of the casing and cementing program, logging procedures, deviation checks, and the drilling, testing and coring program, and proposed annulus fluid. (Request and submission of justifying data must be made to use an alternative to packer for Class I.)

M. **CONSTRUCTION DETAILS** - Submit schematic or other appropriate drawings of the surface and subsurface construction details of the well.

N. **CHANGES IN INJECTED FLUID** - Discuss expected changes in pressure, native fluid displacement, and direction of movement of injection fluid. (Class III wells only.)

O. **PLANS FOR WELL FAILURES** - Outline contingency plans (proposed plans, if any, for Class II) to cope with all shut-ins or wells failures, so as to prevent migration of fluids into any USDW.

P. **MONITORING PROGRAM** - Discuss the planned monitoring program. This should be thorough, including maps showing the number and location of monitoring wells as appropriate and discussion of monitoring devices, sampling frequency, and parameters measured. If a manifold monitoring program is utilized, pursuant to §146.23(b)(5), describe the program and compare it to individual well monitoring.

Q. **PLUGGING AND ABANDONMENT PLAN** - Submit a plan for plugging and abandonment of the well including: (1) describe the type, number, and placement (including the elevation of the top and bottom) of plugs to be used; (2) describe the type, grade, and quantity of cement to be used; and (3) describe the method to be used to place plugs, including the method used to place the well in a state of static equilibrium prior to placement of the plugs. Also for a Class III well that underlies or is in an exempted aquifer, demonstrate adequate protection of USDWs. Submit this information on EPA Form 7520-14, Plugging and Abandonment Plan.

R. **NECESSARY RESOURCES** - Submit evidence such as a surety bond or financial statement to verify that the resources necessary to close, plug or abandon the well are available.

S. **AQUIFER EXEMPTIONS** - If an aquifer exemption is requested, submit data necessary to demonstrate that the aquifer meets the following criteria: (1) does not serve as a source of drinking water; (2) cannot now and will not in the future serve as a source of drinking water; and (3) the TDS content of the ground water is more than 3,000 and less than 10,000 mg/l and is not reasonably expected to supply a public water system. Data to demonstrate that the aquifer is expected to be mineral or hydrocarbon production, such as general description of the mining zone, analysis of the amenability of the mining zone to the proposed method, and time table for proposed development must also be included. For additional information on aquifer exemptions, see 40 CFR Sections 144.7 and 146.04.

T. **EXISTING EPA PERMITS** - List program and permit number of any existing EPA permits, for example, NPDES, PSD, RCRA, etc.

U. **DESCRIPTION OF BUSINESS** - Give a brief description of the nature of the business.

Footnotes (*) for the UIC Permit Application Form

*1 Puna Geothermal Venture (PGV) also conducts drilling activities, which are included under SIC Code 1781.

*2 PGV is currently operating five (5) Class V geothermal injection wells pursuant to:

a. U.S. EPA Region 9 UIC Permit #HI596002.

b. A valid State of Hawaii UIC Permit #UH-1529 issued by the Hawaii Department of Health (HDOH).

EXISTING INJECTION WELL NO.	LOCATE ON WELL PAD	APPROXIMATE WELL HEAD ELEVATION ABOVE MEAN SEA LEVEL
KS-1A	A	617
KS-3	E	618
KS-11	A	617
KS-13	A	618
KS-15	B	743

PROPOSED INJECTION WELL NO.	LOCATE ON WELL PAD	APPROXIMATE WELL HEAD ELEVATION ABOVE MEAN SEA LEVEL
KS-17	A	610
KS-18	E	620
KS-19	TBD	TBD
KS-20	TBD	TBD
KS-21	TBD	TBD
KS-22	TBD	TBD
KS-23	TBD	TBD
KS-24	TBD	TBD
KS-25	TBD	TBD
KS-26	TBD	TBD
KS-27	TBD	TBD

*3 The latitude and the longitude provided identifies the approximate center of the Area of Review and existing well locations as described in Attachment A.

208019
XC: BKM, AN

LINDA LINGLE
GOVERNOR OF HAWAII

LAURA H. THIELEN
CHAIRPERSON
BOARD OF LAND AND NATURAL RESOURCES
COMMISSION ON WATER RESOURCE MANAGEMENT

RUSSELL Y. TSUJI
FIRST DEPUTY

KEN C. KAWAHARA
DEPUTY DIRECTOR - WATER

AQUATIC RESOURCES
BOATING AND OCEAN RECREATION
BUREAU OF CONVEYANCES
COMMISSION ON WATER RESOURCE MANAGEMENT
CONSERVATION AND COASTAL LANDS
CONSERVATION AND RESOURCES ENFORCEMENT
ENGINEERING
FORESTRY AND WILDLIFE
HISTORIC PRESERVATION
KAHOOLAWE ISLAND RESERVE COMMISSION
LAND
STATE PARKS

STATE OF HAWAII
DEPARTMENT OF LAND AND NATURAL RESOURCES

STATE HISTORIC PRESERVATION DIVISION
601 KAMOKILA BOULEVARD, ROOM 555
KAPOLEI, HAWAII 96707

September 19, 2008

Bruce K. Meyers, P.E.
Okahara & Associates, Inc.
200 Kohola Street
Hilo, Hawaii 96720

LOG NO: 2008.3984
DOC NO: 0809MD67
Archaeology

Dear Mr. Meyers:

SUBJECT: Chapter 6E-42 Historic Preservation Review – Request for Comment on a Grading Permit Application for 3.48 acres at the Puna Geothermal Venture Kapoho Ahupuaʻa, Puna District, Island of Hawaiʻi TMK: (3) 1-4-001:002 (por.)

Thank you for the opportunity to comment on the aforementioned project, which we received on September 17, 2008. Your project involves boring holes.

RECEIVED
SEP 24 2008
OKAHARA & ASSOCIATES, INC.
HILO OFFICE

We determine that **no historic properties will be affected** by this project because:

- [x] Intensive cultivation has altered the land
- [ ] Residential development/urbanization has altered the land
- [x] Previous grubbing/grading has altered the land
- [ ] An accepted archaeological inventory survey (AIS) found no historic properties
- [ ] SHPD previously reviewed this project and mitigation has been completed
- [ ] Other:

In the event that historic resources, including human skeletal remains, cultural materials, lava tubes, and lava blisters/bubbles are identified during the construction activities, all work needs to cease in the immediate vicinity of the find, the find needs to be protected from additional disturbance, and the State Historic Preservation Division, Hawaii Island Section, needs to be contacted immediately at (808) 981-2979.

If you have questions about this letter please contact Morgan Davis at (808) 981-2979.

Aloha,

Nancy A. McMahon

Nancy McMahon, Deputy SHPO/State Archaeologist
and Historic Preservation Manager
State Historic Preservation Division

STATE OF HAWAII
DEPARTMENT OF LAND AND NATURAL RESOURCES

STATE HISTORIC PRESERVATION DIVISION
KAKUHIHEWA BUILDING
601 KAMOKILA BLVD, STE 555
KAPOLEI, HAWAII 96707

November 16, 2018

IN REPLY REFER TO:
Log No. 2018.02546
Doc. No. 1811SN05
Archaeology

Michael Yee, Planning Director
County of Hawaii
101 Pauahi Street, Suite 3
Hilo, HI 96720
planning@hawaiicounty.gov

Dear Mr. Yee:

SUBJECT: **Chapter 6E-42 Historic Preservation Review -**
County of Hawaii Grading Permit Application for a Driveway at PGV
Pāhoa Ahupua'a, Puna District, Island of Hawai'i
TMK: (3) 1-4-001:002 and 019 por.

This letter provides the State Historic Preservation Division's (SHPD's) review of the subject application received by our office on October 29, 2018. The landowners, Kapoho Land & Develop LLC, propose construction of two driveways to re-establish access to the Puna Geothermal Venture facilities. Grading work for the driveways will be approximately 80 feet wide and consists of Driveway A (3,700 ft. long) and Driveway B (2,100 ft. long). The proposed grading work will begin at a new intersection point from Highway 132 and end at the Puna Geothermal Venture power plant and well site. Excavation will be through the new lava generated from the 2018 (Fissure 8) eruption and will extend to depth from 0 to 40 feet below the new ground surface. The proposed grading will consist of an approximately 20-acre portion of the combined 517-acre parcels.

SHPD has reviewed several permits for parcel 002, resulting in determinations of no historic properties affected based on the parcel's existing conditions (e.g., April 18, 2006, Log No. 2006.1182, Doc. No. 0604MM16; April 27, 2006, Log No. 2006.1192, Doc. No. 0604MM17; September 19, 2008, Log No. 2008.3984, Doc. No. 0809MD67; April 23, 2009, Log No. 2009.1416, Doc. No. 0904MD13). No historic properties have been identified on parcel 019, and based on recent events, no historic properties are present on this parcel. The current projects will only impact portions of the parcel recently inundated by lava.

Based on current information, **SHPD's determination is no historic properties affected** for the proposed project. Pursuant to HAR §13-284-7(e) When the SHPD agrees that the action will not affect any significant historic properties, this is the SHPD's written concurrence and historic preservation review ends. The historic preservation review process is ended. The permit issuance process may proceed.

Attach to permit: In the unlikely event that subsurface historic resources, including human skeletal remains, structural remains, cultural deposits, sand deposits, or sink holes are identified during the grading work, cease work in the immediate vicinity of the find, protect the find from additional disturbance, and contact the State Historic Preservation Division at (808) 933-7651.

Please contact Sean Nāleimaile at (808) 933-7651 or at Sean.P.Naleimaile@hawaii.gov for any questions or concerns regarding this letter.

Aloha,

Susan A. Lebo

Signed For
Alan S. Downer, PhD
Administrator, State Historic Preservation Division
Deputy State Historic Preservation Officer

cc. Allan Simeon, public_works@hawaiicounty.gov
Robert Masuda, robert.k.masuda@hawaii.gov
Lennie Okano-Kendrick, lokano@okahara.com
Michael Kaleikini, mkaleikini@ormat.com
Robyn Matsumoto, robyn.matsumoto@hawaiicounty.gov

BIOLOGICAL RESOURCES UPDATE

PUNA GEOTHERMAL VENTURE

UIC PERMIT RENEWAL

JUNE 2020

TABLE OF CONTENTS

1.0 INTRODUCTION

Puna Geothermal Resources (PGV) is in the process of renewing Underground Injection Control (UIC) Environmental Protection Agency (EPA) Region 9 Permit No. HI596002. PGV is currently operating 5 Class V geothermal injection wells and is proposing to add 11 additional injection wells as included in the application.

PGV is in receipt of the Species List letter dated March 23, 2020 from the United States Fish and Wildlife Service (USFWS). PGV has reviewed the list and prepared this document to update the status of current habitat conditions present after the 2018 eruption, provide an analysis as to whether potential habitat for each of the species is present, and to provide input on which recommended mitigation measures are applicable for species protection and will be implemented by PGV.

2.0 CURRENT HABITAT AND SOIL CONDITIONS

The additional disturbance and new wells would be installed on two well pads (A and E) as shown in the figure below. All of the wells to be located on Well Pad A are within areas recently covered by 2018 eruption lava flow or on previously disturbed areas. There is no vegetation on the pads and within the proposed operation areas. The photo below shows an example of current pad conditions where operations would take place.

Surrounding habitat includes some areas with native grasses and shrubs. In higher elevations where the lava flow did not reach there is a mixed forest. A species list of the documented species is attached for reference to represent the plant species present in surrounding areas (Attachment A).

Figure 1 – Operation Areas

Example of Well Pad Conditions

3.0 Species Evaluation

Table 1 that describes the preferred habitat of the species provided in the Species List and an evaluation of the potential for occurrence and utilization of the operations area and surrounding habitat.

Table 1
Sensitive Species
Observed or Potentially Occurring in the Project Area

Species	Status Federal/State	Habitat	Potential for Occurrence	Recommended Mitigation Implemented	Recommended Effects Determination
Plants					
Haiwale *Cyrtanda nanawaleensis*	Federally Endangered/State not listed	Moist shaded sites in wet and sometimes mesic forest.	None. Project is out of range of species, no suitable habitat.	No	No effect
Hilo murainagrass *Ischaemum byrone*	Federally endangered/ State endangered	On rocks near the ocean and sometimes further inland up to 250 feet.	None. Project is out of range of species, no suitable habitat.	No	No effect
Birds					
Hawaiian hawk *Buteo solitarius*	Federally delisted/State-listed as Endangered	Forest habitats. Nests predominantly in Ohia trees.	High, foraging only in project area, no nesting habitat present in operations area.	Yes	May effect, but not likely to affect
Hawaiian petrel *Pterodroma sandwichensis*	Federally endangered/State endangered	Nests in lower alpine or subalpine slopes of Mauna Loa.	Low, known range outside of project area including possible flyways from breeding areas.	Partial	May effect, but not likely to affect
Band-rumped storm petrel *Oceanodroma castro*	Federally endangered/State endangered	Nests in crevices or holes in cliff faces and remote lava flows that are extremely difficult to access.	None, known range outside of project area including possible flyways from breeding areas. No active nests have been found on the island of Hawai'i.	Partial	No effect
Newell's shearwater *Puffinus auricularis newelli*	Federally endangered/State threatened	Nests in burrows beneath ferns and tree roots in dense forest and on steep slopes and cliffs.	Low, known range outside of project area including possible flyways from breeding areas.	Partial	May effect, but not likely to affect
Hawaiian goose *Branta (Nesochen) sandvicensis*	Federally threatened/State endangered	Open areas – pastures, golf courses, wetlands, natural grasslands and shrublands, and lava flows	Moderate, suitable habitat available, outside of operations area.	Yes	May effect, but not likely to affect
Mammals					
Hawaiian hoary bat *Antrozous pallidus*	Federally endangered/State endangered	Exotic and native woody vegetation over 15 feet tall	Low, potential to occur outside of operations area.	Yes	May effect, but not likely to affect

4.0 MITIGATION MEASURES EVALUATION

4.1 PLANTS

Listed Plants

There are no listed plants within the project area/operations area, therefore the mitigation measures listed in the Species List are not applicable.

Biosecurity and Invasive Species

PGV is currently and will comply with the Biosecurity Protocols provided.

4.2 BIRDS

Hawaiian Hawk

PGV will comply with the recommended mitigation measures as listed below and coordinate with the Department of Land and Natural Resources, Division of Forestry and Wildlife.

- If work must be conducted during the March 1 through September 30 Hawaiian hawk breeding season, have a biologist familiar with the species conduct a nest search of the project footprint and surrounding areas immediately prior to the start of construction activities. o Pre-disturbance surveys for Hawaiian hawks are only valid for 14 days. If disturbance for the specific location does not occur within 14 days of the survey, conduct another survey.

- No clearing of vegetation or construction activities should occur within 1,600 feet of any active Hawaiian hawk nest during the breeding season until the young have fledged.

- Regardless of the time of year, trees containing a hawk nest should not be cut, as nests may be re-used during consecutive breeding seasons.

Hawaiian Petrel, Newell's Shearwater, and Band-rumped storm petrel

Although there is none to low potential for these species to transit over the project area to breeding grounds and no breeding habitat is present within the project area or vicinity, PGV is already implementing the following recommended mitigation measure:

- Fully shield all outdoor lights so the bulb can only be seen from below bulb height and only use when necessary.

Due to the nature of the drilling operations, PGV will not implement the following recommended mitigation measure for safety reasons:

- Install automatic motion sensor switches and controls on all outdoor lights or turn off lights when human activity is not occurring in the lighted area.

Due to lack of potential for occurrence and impact, PGV will not implement the following mitigation measure:

- Avoid nighttime construction during the seabird fledging period, September 15 through December 15.

Hawaiian Goose

PGV will comply with the recommended mitigation measures as listed below.

- Do not approach, feed, or disturb Hawaiian geese.

- If Hawaiian geese are observed loafing or foraging within the project area during the breeding season (September through April), have a biologist familiar with the nesting behavior of nene survey for nests in and around the project area prior to the resumption of any work. Repeat surveys after any subsequent delay of work of 3 or more days (during which the birds may attempt to nest).

- Cease all work immediately and contact the Service for further guidance if a nest is discovered within a radius of 150 feet of proposed work, or a previously undiscovered nest is found within said radius after work begins.

- In areas where Hawaiian geese are known to be present, post and implement reduced speed limits, and inform project personnel and contractors about the presence of endangered species on-site.

4.3 MAMMALS

Hawaiian Hoary Bat

There is no roosting or hibernacula habitat within the operations area and no vegetation removal will be required. PGV will still agree to the following recommended mitigation measures.

- Do not disturb, remove, or trim woody plants greater than 15 feet tall during the bat birthing and pup rearing season (June 1 through September 15).

- Do not use barbed wire for fencing.

5.0 CONCLUSION

PGV appreciates continued coordination with the USFWS on the protection of sensitive and natural resources. Should you require additional information or have any questions please contact Ron Quesada at 1-808-965-6233 x52848 or rquesada@ormat.com.

ATTACHMENT A
SPECIES LISTS

Table 7-1

ENDEMIC SPECIES FOUND DURING FIELD SURVEY[a]

TAXA	COMMON NAME
FERNS AND FERN ALLIES	
Athyrium sandwichianum	Hoio
Sadleria cyatheoides	Amauma
Cibotium chamissoi	Hapuuii
Cibotium glaucum	Hapuu
Elaphoglossum crassifolium	Ekaha
Dicranopteris emarginata	Uluhe, false staghorn fern
Adenophorus tamariscinus	Wahine-noho-mauna
Mecodium recurvum	Ohiaku
Vandenboschia cyrtotheca	Kilau
Polypodium pellucidum var. volcanicum	Ae
Selaginalla arbuscula	Lepelepaamoa
Christella cyatheoides	Kikawaio
MONOCOTYLEDONS	
Seleria testacea	--
Freycinetia arborea	Ieie

(a) - For more details see Appendix C, which lists genus, author citation of each species, biogeographic status of each species, vegetation type(s) in which the species was observed, and frequency of observation.

Table 7-1

ENDEMIC SPECIES FOUND
DURING FIELD SURVEY[a]
(continued)

TAXA	COMMON NAME
DICOTYLEDONS	
Alyxia olivaeformis	Maile
Ilex anomala	Kawau, kaawau
Tetraplasandra hawaiiensis	Ohe
Perrottetia sandwicensis	Olomea, puaa olomea
Diospyros ferrea subsp. sandwicensis	Lama
Antidesma platyphyllum	Hame
Cyrtandra paludosa var. integrifolia	--
Cyrtandra paludosa var. irrostrata	--
Cyrtandra sp.	--
Hibiscus youngianus	Hauhele, akiohala
Cocculus ferrandianus	Huehue, hueie
Myrsine lessertiana	Kolealaunui
Metrosideros polymorpha	Ohia, ohialehua
Pisonia umbellifera	Papalakepau
Bobea sp.	Ahakea
Psychotria hawaiiensis	Kopiko
Wikstroemia sandwicensis	Akia
Pipturus hawaiensis	Mamaki
Touchardia latifolia	Olona

Federal laws listed under 40 CFR §144.4

(a) The ***Wild and Scenic Rivers Act,*** 16 U.S.C. 1273 ***et seq.*** Section 7 of the Act prohibits the Regional Administrator from assisting by license or otherwise the construction of any water resources project that would have a direct, adverse effect on the values for which a national wild and scenic river was established. Non-applicability

(b) ***The National Historic Preservation Act of 1966,*** 16 U.S.C. 470 ***et seq.*** Section 106 of the Act and implementing regulations (36 CFR part 800) require the Regional Administrator, before issuing a license, to adopt measures when feasible to mitigate potential adverse effects of the licensed activity and properties listed or eligible for listing in the National Register of Historic Places. The Act's requirements are to be implemented in cooperation with State Historic Preservation Officers and upon notice to, and when appropriate, in consultation with the Advisory Council on Historic Preservation. Applicable, Refer to Puna Geothermal Venture 1987 Environmental Impact Statement and Attachment 1 DLNR Historic Preservation Review

(c) The ***Endangered Species Act,*** 16 U.S.C. 1531 ***et seq.*** Section 7 of the Act and implementing regulations (50 CFR part 402) require the Regional Administrator to ensure, in consultation with the Secretary of the Interior or Commerce, that any action authorized by EPA is not likely to jeopardize the continued existence of any endangered or threatened species or adversely affect its critical habitat. Applicable, Refer to Puna Geothermal Venture 1987 Environmental Impact Statement and Attachment 2 USFWS Species List

(d) ***The Coastal Zone Management Act,*** 16 U.S.C. 1451 ***et seq.*** Section 307(c) of the Act and implementing regulations (15 CFR part 930) prohibit EPA from issuing a permit for an activity affecting land or water use in the coastal zone until the applicant certifies that the proposed activity complies with the State Coastal Zone Management program, and the State or its designated agency concurs with the certification (or the Secretary of Commerce overrides the States non-concurrence). Non-applicability

(e) The ***Fish and Wildlife Coordination Act,*** 16 U.S.C. 661 ***et seq.,*** requires the Regional Administrator, before issuing a permit proposing or authorizing the impoundment (with certain exemptions), diversion, or other control or modification of any body of water, consult with the appropriate State agency exercising jurisdiction over wildlife resources to conserve these resources. Non-applicability

(f) ***Executive orders.*** Safe Drinking Water Act (42 U.S.C, 300f et seq.) Applicable, Environmental Protection Agency (EPA) Permit No.HI596002

PUNA GEOTHERMAL VENTURE

An ORMAT Company

Underground Injection Control

Individual Permit

Class V Injection

Permit No. HI596002

Puna Geothermal Venture
Application for Renewal
January 2020

PUNA
GEOTHERMAL
VENTURE
An ORMAT Company

PUNA GEOTHERMAL VENTURE INTRODUCTION

I. Big Island Intro

The Big island of Hawaii is the youngest of the Hawaiian Islands chain and is more than twice the size of all the other islands combined, but it is home to only 165,000 people. The development of clean and reliable alternative sources of energy is essential to the future of our state because Hawaii depends on imported oil for 90% of its energy needs. Solar and wind power, other emerging energy sources, and, of course, geothermal, should all be a part of the energy future of the Big Island. And because the Big Island of Hawaii is growing faster than any other area of the state, it is even more important that we pursue all of these different energy options available to us that will reduce our dependency on imported oil.

II. General Information

PGV produces electric energy from a geothermal power plant and geothermal wellfield located on the Big Island of Hawaii. The project is located approximately 21 miles south of Hilo in the Puna District. PGV is sited on about 500 acres of land in the Kapoho area of which approximately 25 acres house the facility. The PGV facility is in the geologic region known as the East Rift Zone, found on the eastern flank of the Kilauea Volcano.

Our modern facility supplies electric power to homes, businesses and a wide variety of consumers all across the Big Island. PGV is the first commercial geothermal power plant in the state of Hawaii and is currently producing 38 megawatts of power…or enough electricity to meet the energy needs of over 38,000 Big Island residents and visitors.

In addition, the 30 plus people employed at PGV represent a real cross-section of the local community. Our families own homes in the area, attend local schools and churches, and are members of numerous community organizations. PGV also regularly contributes staff time and dollars to local programs and activities. And our annual payroll adds over $2 million to the local economy!

III. Geothermal Energy

Geothermal energy is heat energy that comes from beneath the surface of the earth. "Geo" means earth and "thermal" refers to heat. Geothermal energy is produced from the natural heat that is stored deep below the earth's crust. In areas of volcanic activity, heat is brought to the near surface by intrusion into the earth's crust of molten rock or lava, originating from great depths.

In order to use this natural energy resource here in Hawaii, production wells are drilled far below the surface into the zone where geothermal heat can be extracted in the form of steam and hot water.

Geothermal energy has been used to produce electricity since the early 1900's and is in operation today in many parts of the United States, as well as in other parts of the world. Hawaii has now joined the rest of the world.

IV. Producing Power at PGV

Producing electric power at PGV requires two things. First, wells to extract the resource from the ground; and second, a power plant to convert the geothermal fluids to electricity.

Once a resource is located, using geological information obtained from drilling exploratory wells and other scientific tests, deep wells are drilled into the geothermal resource zone.

Drilling geothermal wells is similar to drilling oil wells. Wells are drilled using a drill rig and take about two months to complete.

PGV has two types of wells – production wells and injection wells. Production wells have been drilled about 4000 to 7,000 feet deep into the geothermal reservoir.

- Current Production Wells:
  - KS-5
  - KS-6
  - KS-9
  - KS-10
  - KS-14
  - KS-16

After the power plant extracts energy from the geothermal fluids, they are returned into the injection wells, which are 6000 to 8,000 feet deep. The injection wells are structurally the same as production wells, with the difference being that injection wells encounter the geothermal resource at a greater depth. This greater depth makes the well more conducive to accepting the fluids back into the reservoir, which closes the loop and renews the resource.

- Current Injection Wells:
  - KS-1A
  - KS-3
  - KS-11
  - KS-13
  - KS-15

As part of the renewal application, first submitted to EPA on October 29, 2015 and updated in January 2020, PGV seeks to increase the number of injection wells. The following is a list of the potential new wells:

- Proposed Injection Wells
  - KS-17
  - KS-18
  - KS-19
  - KS-20
  - KS-21
  - KS-22
  - KS-23
  - KS-24
  - KS-25

- KS-26
- KS-27

Refer to System Operating Procedure (SOP) PGV Geothermal Well Distinction on page 6.

Anything that we extract from our production wells is put back into the ground through these injection wells. We call this our "closed system." Our injection wells are below the geothermal production zone and are far below the water table.

Once the drilling process is completed, power production commences by flowing geothermal fluids from one or more of the production wells. Flow from these wells is controlled by pressure control valves at each well to maintain the design pressure at the power plant steam turbines.

The geothermal fluid is first directed through a flash separator to separate the steam and hot brine. The steam is piped into a (steam) power plant to be used by our geothermal energy conversion units and the geothermal hot brine is directed into the second (brine) power plant which routes the hot brine through heat exchangers to transfer heat to conversion units and then routed to our reinjection system.

Steam Plant

Each of the 10 Ormat energy converters (OECs) first process the steam through a steam turbine. After giving up much of its energy in the steam turbine, the low pressure steam enters a heat exchanger, or vaporizer, where it gives up more energy by boiling a low boiling hydrocarbon, pentane. In the process, the steam condenses into a liquid. When the steam is condensed in the vaporizer, non-condensable gases remain and are collected, compressed, and piped into the reinjection system.

Brine Plant

Each of the 2 Ormat energy converters (OECs) first process the hot brine through heat exchangers where it transfers the heat to boil a low boiling hydrocarbon, pentane. In the process, the lower temperature brine is routed to a collection area and combined with the liquid from the steam plant and piped into the reinjection system.

Back at each OEC, the pentane, which has been vaporized by the steam and hot brine enters the binary turbines and gives up much of its energy.

Then the pentane vapor is exhausted into banks of air coolers which condense the pentane. The liquid pentane flows back to the vaporizer, which starts it through the "closed loop" cycle again. In the steam plant, steam and the pentane turbines are connected to a generator which converts the turbines' mechanical energy to electrical energy. In the brine plant, the pentane turbines are connected to a generator which converts the turbines' mechanical energy to electrical energy. Each OEC has its own control system and operates independently.

In addition, each OEC communicates with Central Station Control. The Operator stationed here can monitor all operations of the OECs, as well as the production and injection wells, and all the other plant system.

The Central Station Control Operator can operate all equipment from his centralized post. He is assisted in operating the facility by two additional operators that monitor conditions at each equipment location.

Included in each of the plant's mechanical and control systems is a high level of redundancy. This provides for continued safe operation when components of the facility require maintenance. In addition, the power plant has environmental control systems employing the best available control technology to minimize plant emissions.

The power plant also has an extensive state-of-the-art environmental monitoring system providing early alerts back to the Operator.

PUNA GEOTHERMAL VENTURE
STANDARD OPERATING PROCEDURE

Title: **PGV Geothermal Well Distinction**	Date: **1/1/20**	Revision: **0**	Page **1** of **1**
	Plant Manager: Jordan Hara		Signature:

Location:

The general location of production and injection is based on the geological model and numerical reservoir modeling to optimize long term operation of the field.

System Description:

Production Well

A well may be used for production if:

- The well is productive, i.e. has sufficient permeability, temperature and pressure for production.
- The production zone is far enough away from injection so thermal breakthrough will not occur too quickly.

Department of Land and Natural Resources (DLNR) will oversee and regulate, in accordance with Chapter 13-183 and 13-184, HAR, the permitting, drilling, construction, testing, modification, production and abandonment of all exploration, monitoring and production geothermal wells per PGV Plan of Operations (POO) permit requirements.

Injection Well

A well may be used for injection if:

- The well is not productive, or low productivity so it is better used for injection.
- The injection zone is far enough away from production so thermal breakthrough will not occur too quickly.
- The injection zone can be connected to production if pressure support is needed.

Environmental Protection Agency (EPA) Region 9 #HI596002 and the Hawaii State Department of Health (HDOH) #UH-1529 will oversee and regulate the permitting, testing and operation of all designated geothermal injection wells per PGV Underground Injection Control (UIC) permit requirements.

PUNA GEOTHERMAL VENTURE INFORMATION SHEET

A Brief History of Geothermal Power

- 1904 - The first geothermal power was extracted in Larderello, Italy.
    - Lit four light bulbs
    - 1911 – First commercial power plant built on the same site
- Today's geothermal story
    - Used for electricity in 26 countries
    - Used for heating in 70 countries
    - About 13 gigawatts of power are produced by geothermal worldwide
    - About 3,500 megawatts are produced in the United States
    - Ormat produces over 500 MW of the U.S. geothermal power
- It is a renewable resource and is stable, that is, it doesn't fluctuate

A Brief History of Puna Geothermal Venture

- 1993 — PGV Launches Operations in June
    - Plant is on the East Rift Zone of Kilauea Volcano in the Puna District
    - 25 megawatts (MW) – Contract with Hawaii Electric Light Co. (HELCO)
- 1996 – first incremental power increase in August
    - +5 MW – Contract amendment with HELCO
- 2004 — Ormat, a world leader in geothermal energy, acquires PGV
    - Undertakes $32 million in upgrades and improvements
    - Concerted effort made to understand cultural and environmental landscape
- 2012 - Production was ramped up to 38 MW, enough to power ~28,000 homes

- +8MW – Contract amendment with HELCO, utilizing brine fraction

- 2018 Eruption Disruption
  - Prior to the eruption, PGV was producing 38 MW of firm, flexible power
    - Enough power to displace approximately 205,000 barrels of oil annually

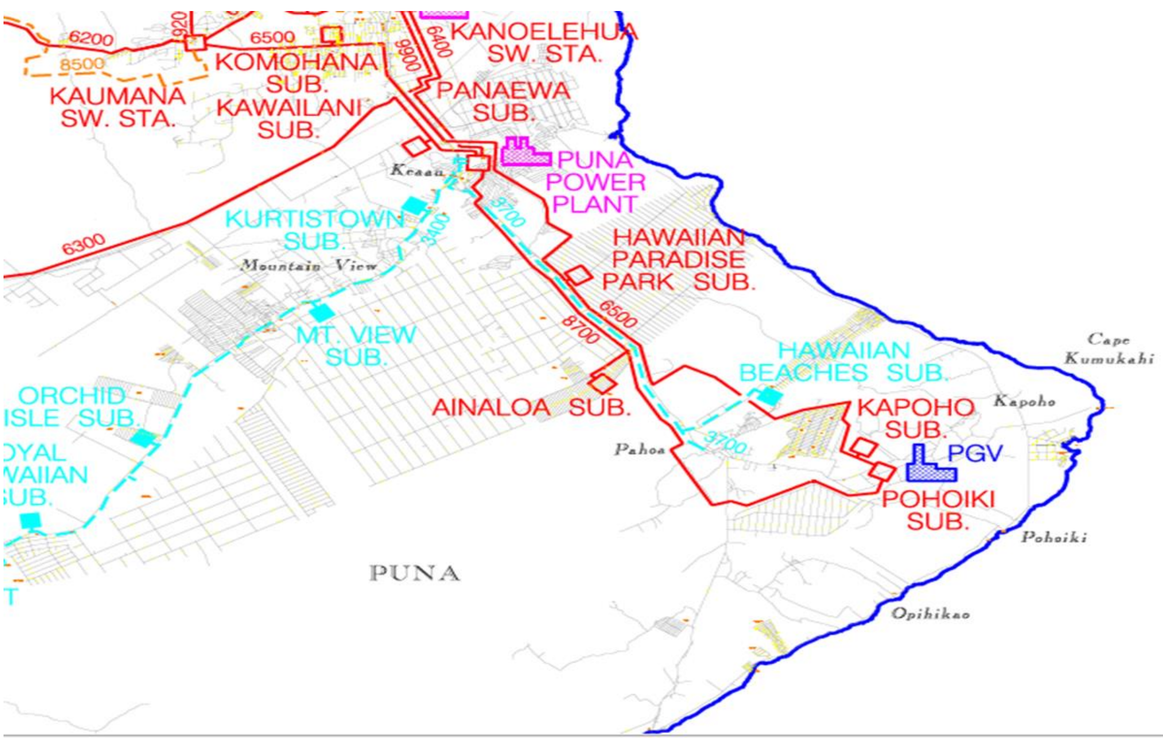
- 2027 – power purchase contract terminates at year end

PGV by the Numbers

- 30 full time staff; kept on payroll through the eruption event
- Pays more than $3 million a year in payroll, benefits and taxes
- 8% gross revenues into either royalties or the local asset fund
  - $15 million in royalties since 1993 — State (50%), County of Hawaiʻi (30%) OHA (20%).
- About a half dozen contractors are retained per MW per year
- 1 MW can power about 750 homes. At 38 MW PGV capable of powering more than 28,000 island homes.

Impacts on the Grid

- Indicate where lines were impacted
- Discuss substation status



UNDERGROUND INJECTION CONTROL PERMIT APPLICATION
PUNA GEOTHERMAL VENTURE

LIST OF ATTACHMENTS

K Injection Procedures

K-1 Injection Chemicals
- SDS B120
- SDS BARRIER FLUID
- SDS CL2150
- SDS GG442
- SDS SODIUM HYDROXIDE
- SDS SULFURIC ACID

Figure K-1 – Simplified Piping and Instrumentation Diagram for Production and Injection Systems

L Construction Procedures

Application for Permit to Drill Proposed Geothermal Well Kapoho State 15 on Reserved Lands, Kapoho, Puna, Hawaii

M Construction Details

Figure 1 – KS-1A Casing Schematic after March 2001 Rework
Figure 2 – KS-3 Completion Schematic after August 1999 Rework
Figure 3 – KS-11 Completion Schematic after March 2013 Rework
Figure 3 – KS-13 Completion Schematic after March 2013 Rework
Figure 5 –KS-15 Schematic of Well Completion July 2015

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O Plans for Well Failures

P Monitoring Program

Appendix A - Hydrologic Monitoring Program
Appendix B - Program for Mechanical Integrity Testing and Monitoring of Injection Wells

Q Plugging and Abandonment Plan

Q-1 - Plugging and Abandonment Plan KS-1A, KS -3, KS-11, KS-13 and KS-15 (EPA Form 7520-14)

R Necessary Resources

Table R-1 – Irrevocable Standby Letter of Credit
Table R-2 – Standby Trust Agreement

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T Issued State and Federal Permits

U Description of Business

V Inventory of Injection Wells (EPA Form 7520-16)

Status of Previously Constructed Wells

Well History

Wellhead Assembly

Wellhead Locations

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X Intentionally Left Blank

Y Intentionally Left Blank

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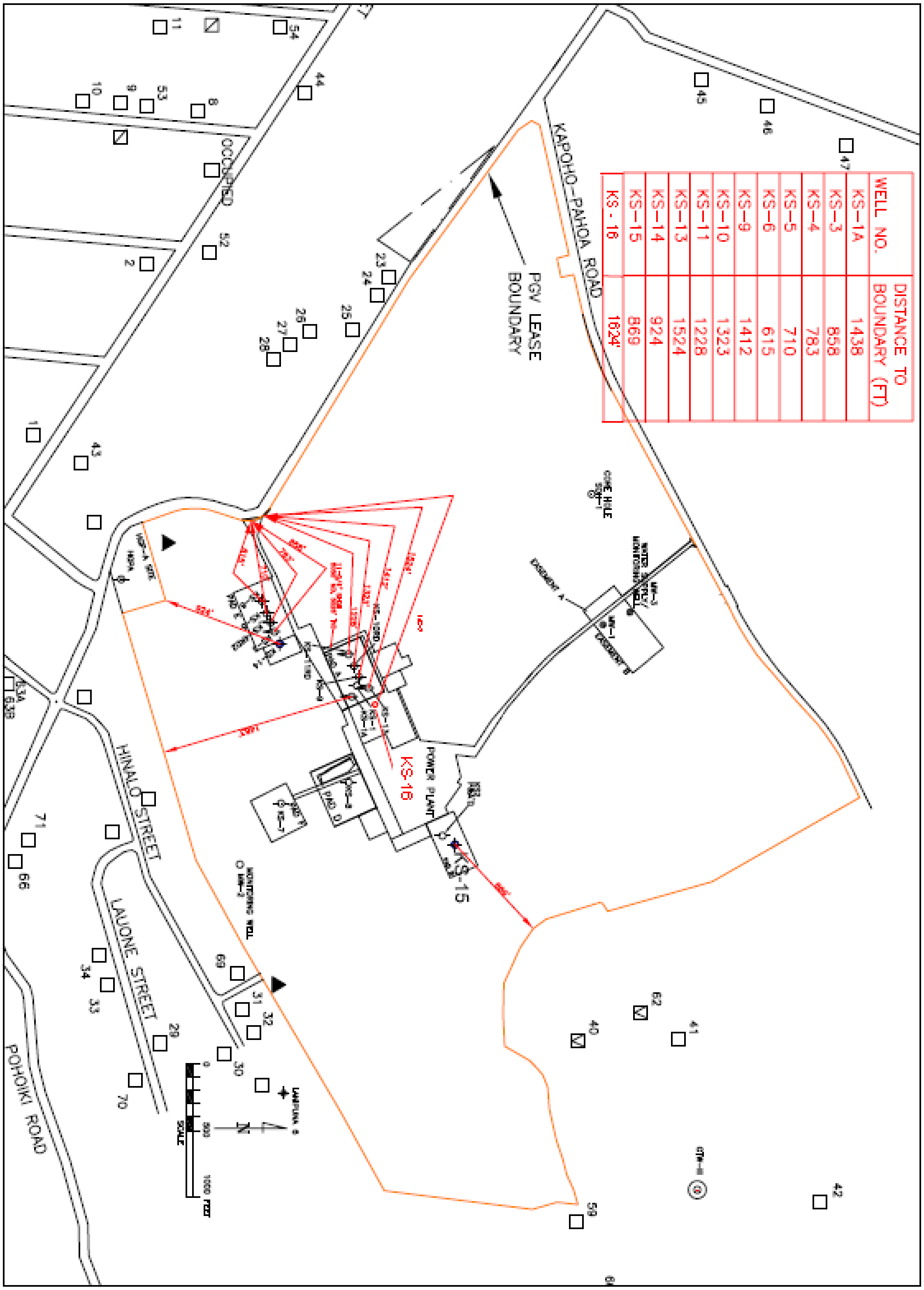
ATTACHMENT A – AREA OF REVIEW

Puna Geothermal Venture (PGV) operates a geothermal power plant on the Island of Hawaii. The facility is located approximately 21 miles southeast of the city of Hilo. The project, which is owned by PGV, occupies approximately 25 to 30 acres on a 500-acre parcel of land leased by PGV, as shown on the location map (see Attachment B, Figure B-1). The PGV leased property is located within the Kapoho section of the Kilauea Lower East Rift Geothermal Resource Subzone, which was designed in 1984 as a geothermal resource subzone for geothermal exploration and development pursuant to Hawaii Revised Statues (HRS) §205-5.1.

The leased property boundary plus an additional quarter-mile strip of land outside the boundary constitutes the Area of Review. The Area of Review boundary is identified on the location map (see Attachment B, Figure B-1).

PUNA GEOTHERMAL VENTURE (PGV) WELL LOCATIONS

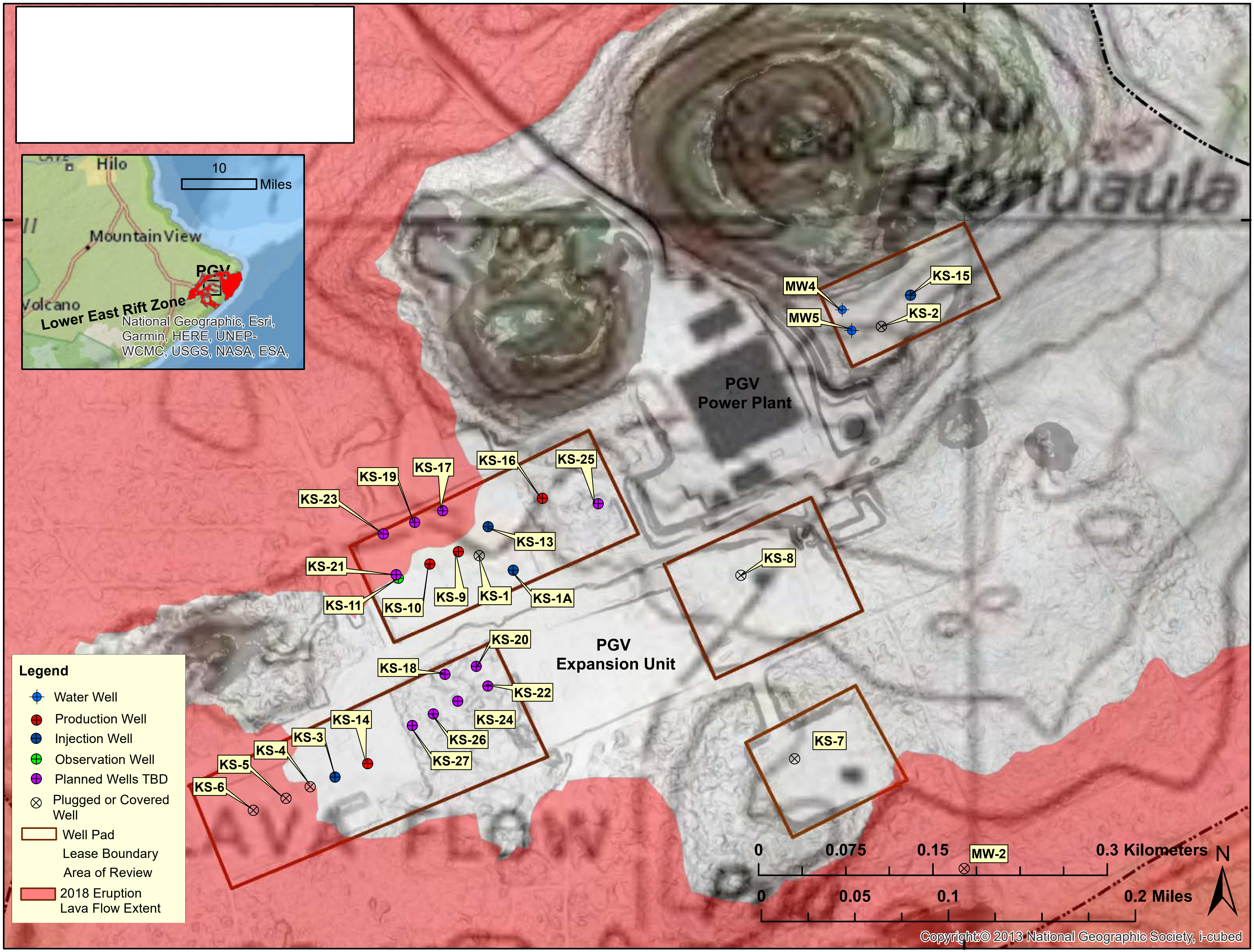
WELL	DEVELOPER	LATITUDE	LONGITUDE
KS-1 Injection	PGV	N 19° 28’ 37.8”	W 154° 53’ 24.4”
KS-1A P&A	PGV	N 19° 28’ 37.3”	W 154° 53’ 23.9”
KS-2 P&A	PGV	N 19° 28’ 43.9”	W 154° 53’ 13.8”
KS-3 Injection	PGV	N 19° 28’ 31.4”	W 154° 53’ 29.3”
KS-4 P&A	PGV	N 19° 28’ 31.1”	W 154° 53’ 29.9”
KS-5 Production	PGV	N 19° 28’ 30.7”	W 154° 53’ 30.6”
KS-6 Production	PGV	N 19° 28’ 30.3”	W 154° 53’ 31.6”
KS-7 P&A	PGV	N 19° 28’ 31.8”	W 154° 53’ 14.8”
KS-8 P&A	PGV	N 19° 28’ 36.9”	W 154° 53’ 17.1”
KS-9 Production	PGV	N 19° 28’ 37.6”	W 154° 53’ 25.5”
KS-10 Production	PGV	N 19° 28’ 37.4”	W 154° 53’ 26.4”
KS-11 Injection	PGV	N 19° 28’ 37.1”	W 154° 53’ 27.4”
KS-13 Injection	PGV	N 19° 28’ 38.5”	W 154° 53’ 24.7”
KS-14 Production	PGV	N 19° 28’ 31.6”	W 154° 53’ 28.5”
KS-15 Injection	PGV	N 19° 28’ 44.7”	W 154° 53’ 12.7”
KS-16 Production	PGV	N 19° 28’ 39”	W 154° 53’ 23.9”



WELL NO.	DISTANCE TO BOUNDARY (FT)
KS-1A	1438
KS-3	858
KS-4	783
KS-5	710
KS-6	615
KS-9	1412
KS-10	1323
KS-11	1228
KS-13	1524
KS-14	924
KS-15	869
KS - 16	1624'

ATTACHMENT B – MAPS OF WELL/AREA AND AREA OF REVIEW

The Area of Review, as described in Attachment A, was reviewed to develop the requisite data for this application. Figure B-1 is a topographic map of the Area of Review and identifies the production wells, injection wells, abandoned wells, temporarily plugged wells, dry holes, monitoring wells, and other pertinent surface features, including residences and roads. The evaluation of the Area of Review verified the absence of drinking water wells, surface bodies of water, springs, mines, and/or quarries. A discussion of the hydrology and geology within the Area of Review is provided in Attachments D, respectively. The information used to create the topographic map was obtained from publicly available sources.



302000
2155000
Hilo
10
Miles
Mountain View
PGV
Volcano
Lower East Rift Zone
National Geographic, Esri, Garmin, HERE, UNEP-WCMC, USGS, NASA, ESA,
MW4
KS-15
MW5
KS-2
PGV
Power Plant
KS-16
KS-25
KS-17
KS-19
KS-23
KS-13
KS-8
KS-21
KS-11
KS-10
KS-9
KS-1
KS-1A
PGV
Expansion Unit
KS-20
KS-18
KS-22
KS-24
KS-14
KS-3
KS-4
KS-26
KS-5
KS-27
KS-6
KS-7
MW-2
Legend
Water Well
Production Well
Injection Well
Observation Well
Planned Wells TBD
Plugged or Covered Well
Well Pad
Lease Boundary
Area of Review
2018 Eruption Lava Flow Extent
0
0.075
0.15
0.3 Kilometers
0
0.05
0.1
0.2 Miles
N
Copyright:© 2013 National Geographic Society, i-cubed

ATTACHMENT C – CORRECTIVE ACTION PLAN AND WELL DATA

All wells in the Area of Review, excluding injection wells that penetrate the proposed injection zone are described in this attachment. Attachment B, Figure B-1, shows the location of these wells. Table C-1 specifies well type, construction, date drilled, and depth. Plugging and abandonment records are included in Table C-1.

Unabandoned wells within the Area of Review are not expected to be detrimentally affected by PGV injection activity. This conclusion is largely based on the fact that there has been no significant buildup of pressure in the injection reservoir since operations began in April, 1993. As shown in Table C-2, the average of static downhole pressure measurements in the three original injection wells (KS-1A, KS-3, and KS-4) and including the two new additional wells (KS-11and KS-13) prior to the start of their individual operations was 2,359 psig at a datum 5,880 feet vertically below mean sea level (MSL). Injection well KS-4 was converted to production in 2006, then later plugged and abandoned in 2010. Based on the most recent downhole survey measurements of the 4 current injection wells, the average shut-in pressure in the injection wells is 2,289 psig. These surveys are included in Attachment C as "12-Hour Shut-In." They were performed in April of 2014. The newest injection well, KS-15 was not in service at the time of the 2014 testing. If these shut-in readings are taken to represent true reservoir pressure, they represent a decrease of 70 psig since the project start-up.

Other pertinent factors regarding unabandoned wells (except injection wells) penetrating the injection zone are presented below.

KS-5, KS-6, KS-9, KS-10, KS-14, and KS-16 PGV's current production wells, KS-5, KS-6, KS-9, KS-10, KS-14, and KS-16 (KS-17 through KS-27 production wells TBD) produce from the Rift Zone fault in a depth range corresponding to the transition zone, which overlies the injection reservoir. Although not physically confirmable, it is considered most likely that the production wells are hydraulically connected to the injection reservoir and that at least a portion of the injectate returns to the production wells. However, regardless of whether or not there is hydraulic connectivity, the USDW is adequately protected from interzonal flow at the production wells.

HGP-A and Lanipuna 6 HGP-A and Lanipuna 6 have been plugged and abandoned. The programs were approved by Hawaii Department of Land and Natural Resources. PGV does not have records of these wells because they were owned by other companies.

SOH-1 For the following reasons, SOH-1 exploratory core hole is not considered to be a potential flow path from the injection reservoir to the USDW.

- It does not penetrate any permeable zones in the geothermal reservoir. As shown in Figure C-3, the lower 1,300 feet of the well exhibit a conductive temperature gradient, which indicates no vertical permeability.
- The 7-inch casing is cemented from 1,996 feet (below ground surface) to the surface.

REFERENCES

GeothermEx, Inc., 1995, "Well HGP-A, Puna, Hawaii, Recommended Procedure for Well Plugging and Abandonment, prepared for State of Hawaii Department of Business, Economic Development and Tourism, Honolulu, Hawaii, December 1995.

Chen, B.H., et al. 1979, "Well Test Analysis of HGP-A," SPE Paper No. 7963.

Table C-1
DATA ON WELLS WITHIN THE AREA OF REVIEW
(Not Including Injection Wells)

Well Name	Date Spudded/ Completed	Well Type	Total Depth *(ft KB)*	Elevation Grnd/KB *(ft)*	Status	Casing & Liners Sizes	Depths *(ft KB)*	Remarks
Kapoho	09/01/81	exploratory	7,290	619/637	P&A	20 in	0 - 71	cmtd
State 1	11/12/81				05/17/93	13-3/8 in.	0 - 903	cmtd
						9-5/8 in.	0 - 4,072	cmtd
						7 in.	3,898 - 7,216	slotted liner
Kapoho	01/19/82	exploratory	7,816	718/736	P&A	20 in	0 - 68	cmtd
State 2	Apr-82				05/26/93	13-3/8 in.	0 - 1,313	cmtd
						9-5/8 in.	0 - 4,209	cmtd
						7 in.	4,200 - 7,816	slotted liner
Kapoho	08/22/02	production	6,418	619	Wellhead	22 in.	0 - 900	cmtd
State 5	01/12/03				covered	16 in.	0 - 2205	cmtd
WO Date	09/03/09				by lava	11-3/4 in.	0 - 5077	cmtd
	10/10/09		6,484			9-5/8 in.	1721 - 3110	cmtd
						7 in.	1616 - 5510	cmtd
						4 1/2 in.	5437 - 6463	perf liner
Kapoho	06/26/05	production	6,584	619	Wellhead	22 in.	0 - 917	cmtd
State 6	08/12/05				covered	16 in.	0 - 2053	cmtd
WO Date	06/14/09				by lava	11-3/4 in.	0 - 5062	cmtd
	07/07/09		6,644			8-5/8 in.	4848 - 6414	cmtd
						7 in.	6265 - 6595	perf liner
Kapoho	05/02/91	exploratory/	3,488	629	P&A	20 in	0 - 1032	cmtd
State 8	08/11/92	production			05/01/93	13-3/8 in.	0 - 2128	cmtd
						9-5/8 in.	0 - 2072	cmtd
Kapoho	12/06/92	production	4,428	618	idle	20 in	0 - 935	cmtd
State 9	01/25/93					13-3/8 in.	0 - 2005	cmtd
WO Date	05/26/19					9-5/8 in.	0 - 3224	cmtd
	06/26/19					7 in.	3024 - 4169	cmtd liner
						7 in.	0 - 956	cmtd liner
Kapoho	02/01/93	production	4,914	618	idle	20 in	0 - 954	cmtd
State 10	04/06/93					13-3/8 in.	0 - 2048	cmtd
WO Date	05/22/05					9-5/8 in.	0 - 4033	cmtd
	06/11/05		5,061.00			7 in.	3798 - 4692	cmtd liner
Kapoho	02/07/10	production	5,717	620	active	22 in.	0 - 955	cmtd
State 14	04/02/10					16 in.	0 - 2201	cmtd
WO Date	04/05/19					11-3/4 in.	0 - 4878	cmtd
	11/?/2019					8-5/8 in.	4747 - 5716	perf liner
Kapoho	02/16/15	production	5,762	616	active	20 in	0 - 1034	cmtd
State 16	05/05/15					13-3/8 in.	0 - 2550	cmtd
						9-5/8 in.	0 - 5003	cmtd
						7"	4921 - 5740	perf liner
HGP-A	12/10/75	exploratory/	6,450	610	P&A	20 in	0 - 386 GL	cmtd

	04/28/76	production		(approx)	1999	13-3/8 in. 9-5/8 in. 7 in. 7 in.	0 - 969 GL 0 - 2,216 GL 0 - 2,921 GL 2,921 - 6,435 GL	cmtd cmtd cmtd slotted liner
Lanipuna 6	02/10/81 05/26/81	exploratory	8,389 Bridged at 7,265	565	P&A 2000	13-3/8 in. 9-5/8 in. 7 in. 7 in.	0 - 75 0 - 1,258 1,086 - 4,239 0 - 4,239	cmtd cmtd cmtd liner cmtd tieback
SOH-1	Completed 01/06/91	exploratory core hole	5,526	600 (approx)	idle	9-5/8 in. 7-in. 4-1/2 in. 2-3/8 in.	0 - 202 0 - 1,996 0 - 3,022 0 - 5,526 3,021 - 5,521	cmtd cmtd uncmtd uncmtd 1/2-in. perfs

Mechanical Integrity Tests
Injection Well KS-13

March 2019

Facility:

Puna Geothermal Venture
14-3860 Kapoho-Pahoa Road
Pahoa, Hawaii 96778

Client:

Puna Geothermal Venture
P. O. Box 30
Pahoa, Hawaii 96778
Attention: Mr. Ron Quesada

July 12, 2019

7601 Anthony Avenue
Garden Grove, California 92841
(714) 879-7900

PUNA GEOTHERMAL VENTURE

MECHANICAL INTEGRITY TESTS OF WELL KS-13

March 2019

Summary

Mechanical integrity tests consisting of temperature / pressure surveys and a nitrogen pressure test were performed in injection well KS-13 during March 2019. The test was done according to PGV's "Program for Mechanical Integrity Testing and Monitoring of Injection Wells," dated July 29, 1996. The tests demonstrated satisfactory internal and external mechanical integrity.

Well Completion

The mechanical configuration of KS-13 is shown in Figure 1. The well was drilled as an injection well during 2005. The well was subjected to extensive injection testing during November and December 2005 and entered permanent injection service in early 2006. The hang-down liner was replaced during January 2013. The well was redrilled and completed with two injection legs during 2016.

Shut-in Temperature Surveys

Beginning March 12, 2019, temperature / pressure surveys were run in KS-13 during injection and after shut-in to measure downhole temperatures and pressures and define the thermal recovery profiles. Injected water was from fresh water well MW-4. The surveys were run by PGV personnel using electronic memory-type instruments. Prior to shut-in, the injection rate was 750 gpm at 130°F injectate temperature and -13 psig wellhead pressure (13 psig vacuum). The injection survey was run on March 12, 2019, and the well was shut in at 16:34 hours. A shut-in temperature survey was run March 13, 2019, approximately 19 hours after shut-in. Following this survey, the well remained shut in. Temperature and pressure data from electronic data files are included in Appendix A.

The March 2019 surveys are plotted in Figure 2. Also plotted in Figure 2 is a shut-in survey run on July 22, 2016, 12 hours after shut-in. The March 2019 surveys show normal thermal recovery and give no indication of fluid communication behind casing.

The well was surveyed only to 4,335 feet to avoid tangling the tool in the dual completion kickoff point at 4,400 feet. The total surveyed depth is 531 feet above the casing shoe and well below the confining layer, so the survey is adequate for demonstrating mechanical integrity.

Nitrogen Pressure Test

A nitrogen pressure test was performed in well KS-13 on March 15, 2019, while the well was shut in. Test specifications in PGV's "Program for Mechanical Integrity Testing and Monitoring of Injection Wells" require that the water level be depressed to 3000 feet KB and that the rate of nitrogen leak-off must not exceed 10% of the initial pressure in five (5) hours. Operating conditions of the well and the calculated nitrogen pressure required to depress the water level to 3000 feet are listed in Table 1. As shown in the table, the calculated required minimum nitrogen annulus test pressure under the average operating conditions during the five-hour test was 1160 psig. The maximum annulus nitrogen pressure that could be maintained without the annulus evacuating (u-tubing) was 910 psig. Acoustic measurements were made using Echometer Company equipment to verify the depth of the fluid level in the well during the test. The acoustic measurement record is included in Appendix B and shows the fluid level was depressed to 3357 feet at an annulus pressure of 900 psig.

Nitrogen pressure on the casing was increased to 910 psig by injecting nitrogen through an annulus valve on the wellhead. Nitrogen injection was then stopped, the valve was shut, and the annulus pressure was observed and recorded for a test period of five (5) hours. Table 2 is a log of the test times, pressures and other data recorded by the operator. Annulus pressure readings in the table, representing pressure between the hangdown liner and cemented casing, were taken from a gauge at the wellhead (listed under "Local Readings"). Wellhead pressure and temperature readings were recorded from wellhead instrumentation. As shown in the table, annulus pressure varied between 905 and 910 psig during the 5-hour test period from 12:00 to 17:00 hours March 15, 2019, a variation of 0.5 percent. A second set of pressure gauge data (PT-2411E2) shows the annulus pressure varied between 898 and 899 psig during the test, a variation of 0.1 per cent. Wellhead pressure and temperature were fairly constant during the test period. "Recorder Data" readings were not recorded because there was no electrical power to the plant at the time of the test.

The EC Group West, LLC

Ross Denton

Ross H. Denton
California Professional Geologist #4352
California Certified Hydrogeologist #497

Table 1

KS-13: CALCULATION OF MINIMUM REQUIRED ANNULUS NITROGEN PRESSURE MIT NITROGEN PUMP-DOWN TEST

(Annulus Fluid Level at 3000 ft KB)

Operating Conditions

Date	3/15/2019
Injection Flow Rate (gpm)	0
Wellhead Pressure (psig)	10
Injectate Temperature (F)	200
Injectate TDS (ppm)	5,800

Well Data

Measured Depth to Bottom of Hangdown Liner (ft KB)	3357
Vertical Depth to Bottom of Hangdown Liner (ft KB)	3357
Vertical Depth to 3000 ft MD KB	3000
Hangdown Liner ID (in.)	7.837
KB Height Above Ground Level (ft)	27.0

Calculated Values

Injectate Density (lb/cu ft)	60.36
Flowing Pressure Loss in Hangdown Liner (psi)	0.0
Pressure at Bottom of Hangdown Liner (psig)	1406
Annulus Pressure at Interface, 3000 ft MD KB	1256
Required Annulus Nitrogen Pressure at Wellhead (psig)	**1160**

Nitrogen Gradient Calculations

MD KB *(ft)*	Nitrogen Pressure *(psig)*	MD KB *(ft)*	Nitrogen Pressure *(psig)*
3000	1256	1500	1207
2900	1253	1400	1204
2800	1250	1300	1201
2700	1246	1200	1197
2600	1243	1100	1194
2500	1240	1000	1191
2400	1236	900	1188
2300	1233	800	1185
2200	1230	700	1181
2100	1226	600	1178
2000	1223	500	1175
1900	1220	400	1172
1800	1217	300	1169
1700	1213	200	1166
1600	1210	100	1163
1500	1207	27	1160

Table 2: March 2019 KS-13 Nitrogen Pressure Test

Purpose: Conduct annual UIC permit required nitrogen annulus pressure test.

Procedure:
1. Increase nitrogen annulus pressure to required value calculated in Excel Spreadsheet.
2. Use Recorder reading in MCC as target for reaching required pressure.
   Test pressure may be higher than the required minimum.
3. Shut off nitrogen and observe pressure for five (5) hours.
4. Using logsheet, take the appropriate readings once every ten (10) minutes during the first hour.
5. After the first hour, take one set of readings every thirty (30) minutes for another four (4) hours.
6. Maximum allowable leak off rate is 10% during the five (5) hour duration.
   If leak off exceeds 10%, check for leaks at the wellhead and repeat test.
7. Check all valves to pts to ensure they are open. Verify local PIs and PTs match prior to test.

Date: 15-Mar-19

Operator: JF

Required Annulus Nitrogen Pressure at Wellhead (psig): **1160**

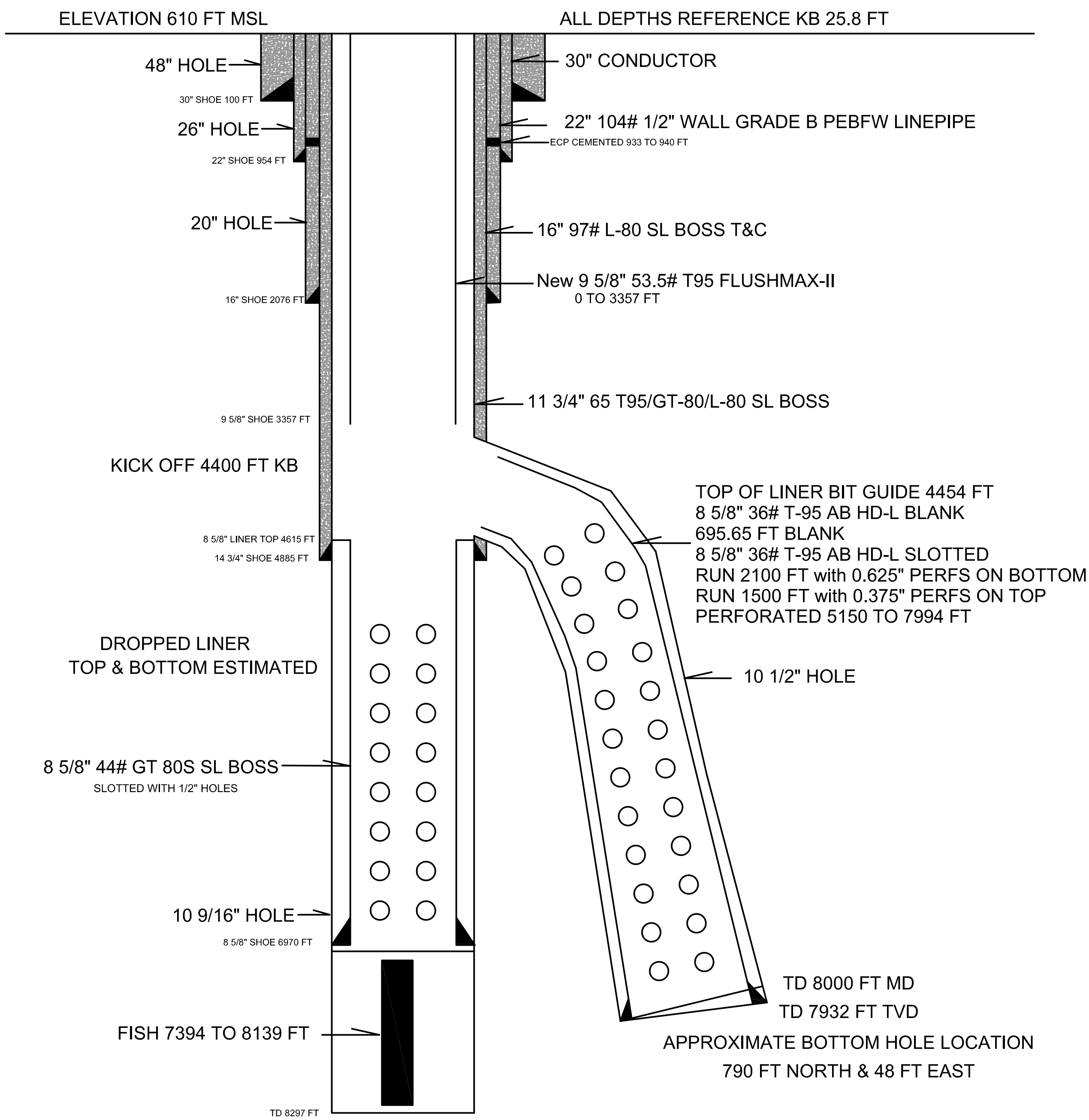
Time	Wellhead Data (Local Readings)				Recorder Data (MCC Building)		
	Temperature (PI-2411E2)	Pressure (PI-2411E2)	Annulus Pressure (PI)	Annulus (PT-2411E2)	Annulus (Green Pen %)	Flow Rate (Red Pen %)	Injection Line (Blue Pen %)
12:00	92	10	910	898			
12:10	98	10	910	899			
12:20	96	10	910	899			
12:30	95	10	910	898			
12:40	96	10	910	899			
12:50	95	10	910	898			
13:30	98	10	910	899			
14:00	98	10	910	899			
14:30	95	10	910	899			
15:00	94	10	910	899			
15:30	90	10	908	899			
16:00	88	10	905	898			
16:30	88	10	908	898			
17:00	88	10	910	898			

Comments:

FINAL COMPLETION DIAGRAM
KS-13 with MULTI-LEG COMPLETION
KS-13 ML-1

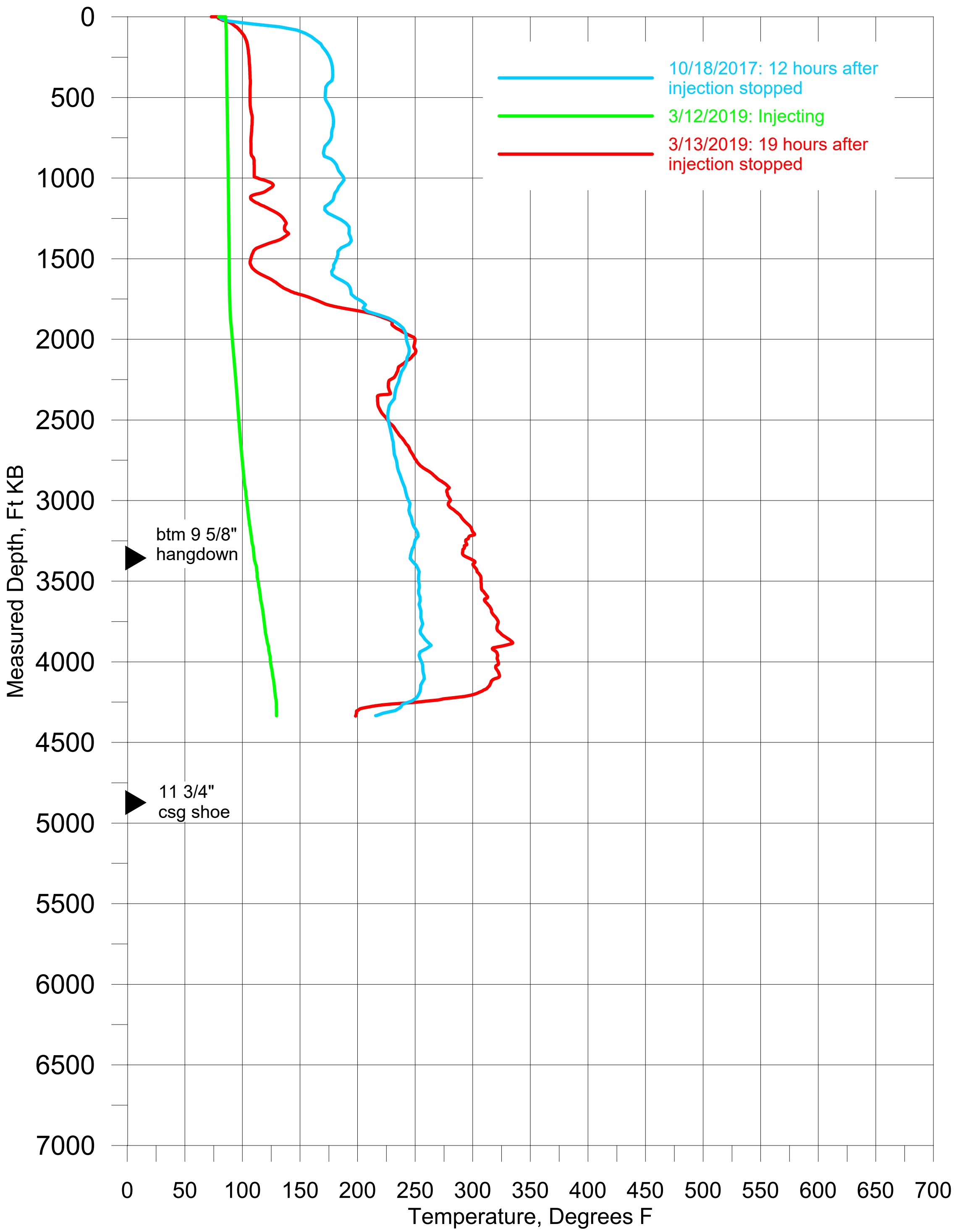
LATITUDE: 19º 28' 39" N   LONGITUDE: 154º 53' 23.9" W

PUNA FIELD, HAWAII



NOT DRAWN TO SCALE
PUNA GEOTHERMAL VENTURE
JUNE 14, 2016

FIGURE 2
PUNA GEOTHERMAL VENTURE
KS-13 TEMPERATURE SURVEY:
MECHANICAL INTEGRITY TEST: MARCH 2019



Appendix A

TEMPERATURE / PRESSURE SURVEY DATA

Puna Geothermal Venture Well KS-13 Temperature / Pressure Survey During Injection March 12, 2019		
Depth (feet)	Temperature (˚F)	Pressure (psig)
50	85.6	-13.0
100	85.9	-13.0
250	86.2	-12.4
500	86.6	-10.2
750	87.2	-7.4
1000	87.7	15.3
1250	88.0	122.1
1500	88.4	230.2
1750	89.0	337.9
2000	91.1	445.2
2250	94.2	550.5
2500	96.8	660.2
2750	99.8	768.4
3000	103.7	874.1
3250	108.2	982.9
3500	113.4	1089.4
3750	118.8	1195.0
4000	124.2	1301.4
4250	129.4	1407.6
4335	129.5	1439.6

Puna Geothermal Venture Well KS-13 March 12, 2019 Well Shut- in @ 16:34 hours Tool hung at 1500 feet		
Time	**Temperature (ºF)**	**Pressure (psig)**
16:34	90.3	233.1
16:35	90.3	234.5
16:36	90.3	234.1
16:38	90.4	233.3
16:40	90.4	234.4
16:45	90.5	234.2
16:50	90.6	243.4
16:55	90.6	309.3
17:00	90.0	342.0
17:05	90.4	343.7
17:10	90.6	349.0
17:15	90.9	353.0
17:19	91.1	361.2
17:25	91.5	361.2
17:30	91.7	364.0
17:35	92.0	364.7
17:40	92.2	367.7
17:45	92.4	372.1
17:50	92.6	377.1
17:55	92.8	374.1
18:00	92.9	378.2
18:05	93.0	539.2
18:10	93.2	623.8
18:15	93.5	645.1
18:20	93.8	652.2
18:25	94.3	657.5
18:30	94.6	660.7
18:35	94.8	662.4
18:45	94.8	665.2
18:55	95.0	363.3
19:05	95.2	174.3
19:15	95.4	146.5
19:25	95.6	140.9
19:35	95.8	139.3
19:45	95.9	139.1

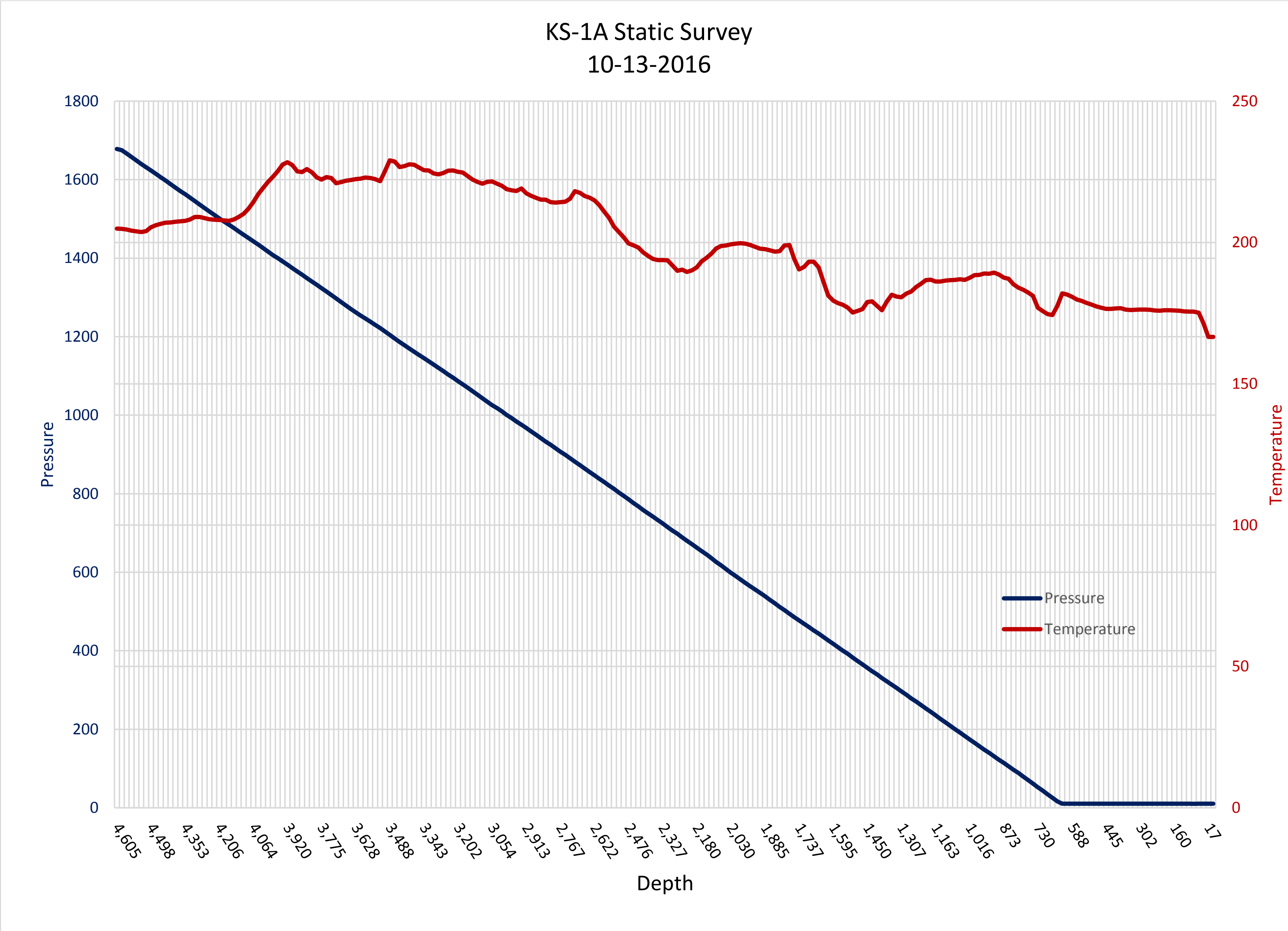
Puna Geothermal Venture Well KS-13 Static Temperature / Pressure Survey		
March 13, 2019, 19 hours after injection stopped		
Depth (feet)	Temperature (˚F)	Pressure (psig)
50	92.3	-12.8
100	99.6	-12.8
250	105.7	-13.0
500	106.6	-13.3
750	107.4	-13.4
1000	113.3	-13.4
1250	135.4	95.7
1500	107.3	202.0
1750	161.9	308.6
2000	249.8	411.8
2250	228.3	514.0
2500	226.0	617.1
2750	250.9	719.4
3000	280.6	820.5
3250	293.8	920.2
3500	307.1	1019.7
3750	322.0	1117.6
4000	322.1	1215.2
4250	251.0	1313.8

Appendix B

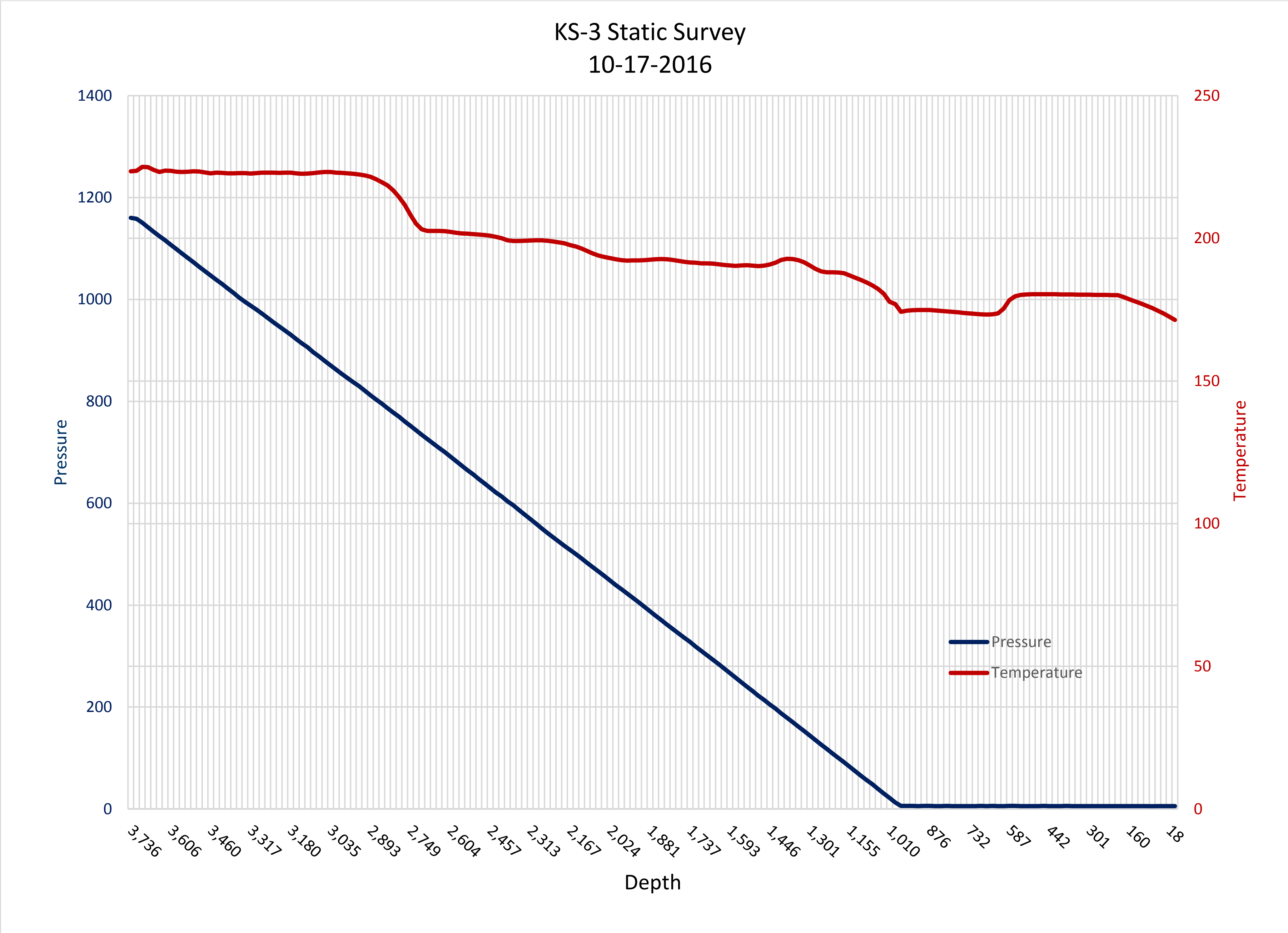
ECHOMETER RECORD

Well	KS-13 Dual Leg
Date	3/15/2019
Time	15:59
Calculated PS	1160
Annulas PSI	900
WHP	10
WHT	200
Flow Rate	0
Seconds	5.06
Velosity	1326.8
Fluid Depth	3357

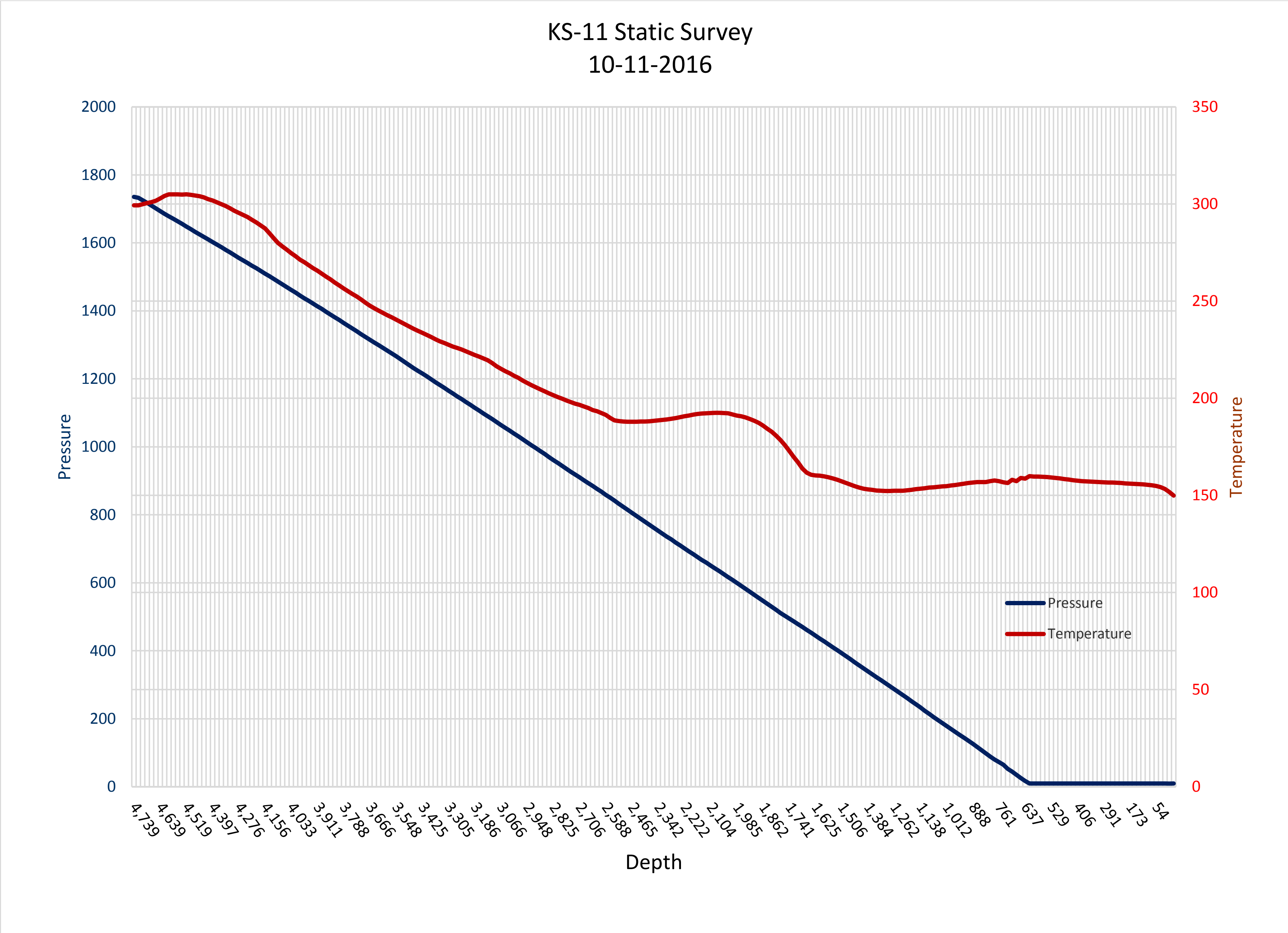
Nitrogen U-tubed at 910 psi



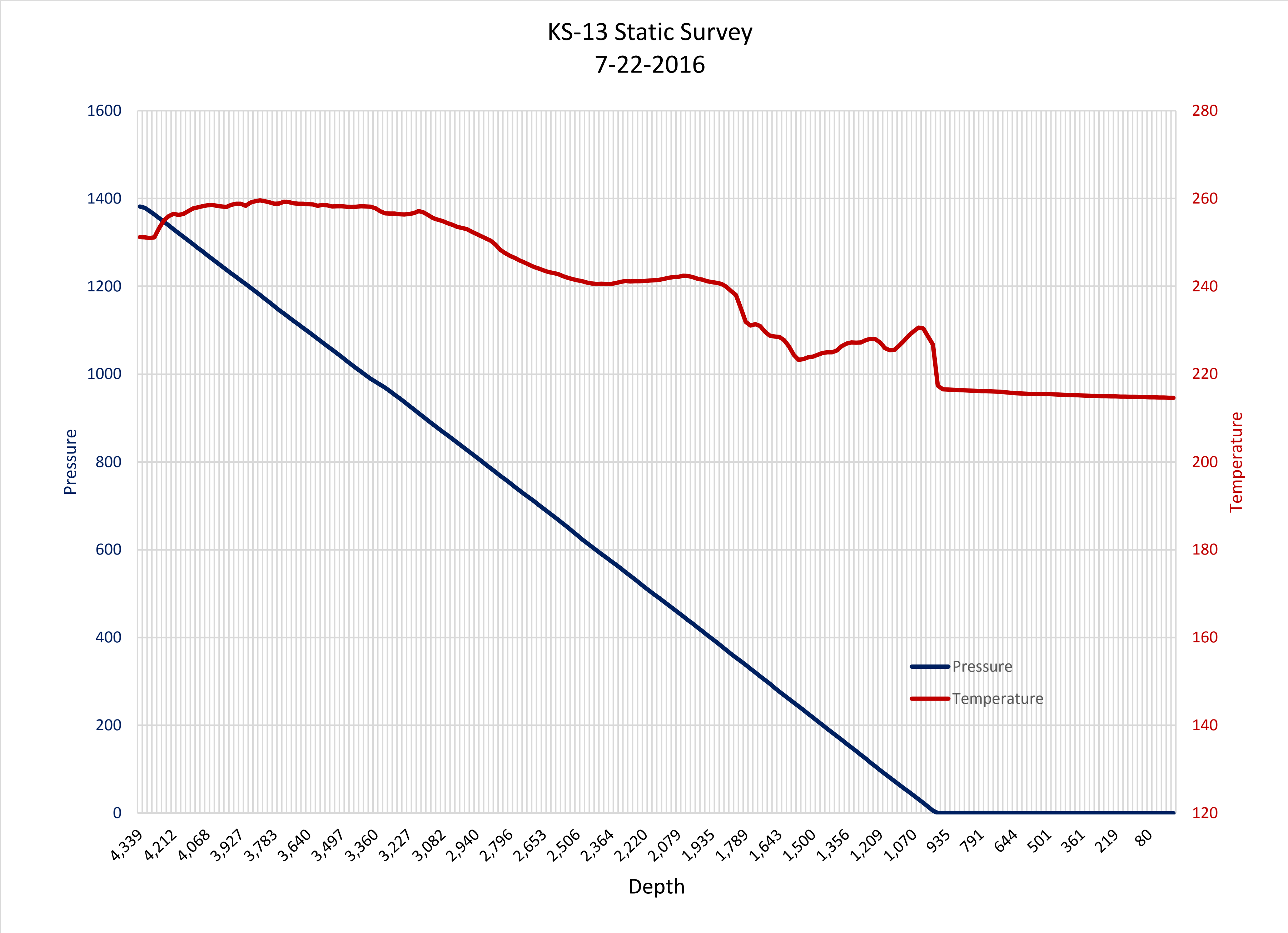
KS-1A Static Survey
10-13-2016
Pressure
Temperature
Depth
1800
1600
1400
1200
1000
800
600
400
200
0
250
200
150
100
50
0
4,605
4,498
4,353
4,206
4,064
3,920
3,775
3,628
3,488
3,343
3,202
3,054
2,913
2,767
2,622
2,476
2,327
2,180
2,030
1,885
1,737
1,595
1,450
1,307
1,163
1,016
873
730
588
445
302
160
17
Pressure
Temperature



KS-3 Static Survey
10-17-2016
Pressure
Temperature
Depth
1400
1200
1000
800
600
400
200
0
250
200
150
100
50
0
3,736
3,606
3,460
3,317
3,180
3,035
2,893
2,749
2,604
2,457
2,313
2,167
2,024
1,881
1,737
1,593
1,446
1,301
1,155
1,010
876
732
587
442
301
160
18
Pressure
Temperature



KS-11 Static Survey
10-11-2016
Pressure
Temperature
Depth
2000
1800
1600
1400
1200
1000
800
600
400
200
0
350
300
250
200
150
100
50
0
4,739
4,639
4,519
4,397
4,276
4,156
4,033
3,911
3,788
3,666
3,548
3,425
3,305
3,186
3,066
2,948
2,825
2,706
2,588
2,465
2,342
2,222
2,104
1,985
1,862
1,741
1,625
1,506
1,384
1,262
1,138
1,012
888
761
637
529
406
291
173
54
Pressure
Temperature


KS-13 Static Survey
7-22-2016
Pressure
Temperature
Depth
1600
1400
1200
1000
800
600
400
200
0
280
260
240
220
200
180
160
140
120
4,339
4,212
4,068
3,927
3,783
3,640
3,497
3,360
3,227
3,082
2,940
2,796
2,653
2,506
2,364
2,220
2,079
1,935
1,789
1,643
1,500
1,356
1,209
1,070
935
791
644
501
361
219
80
Pressure
Temperature

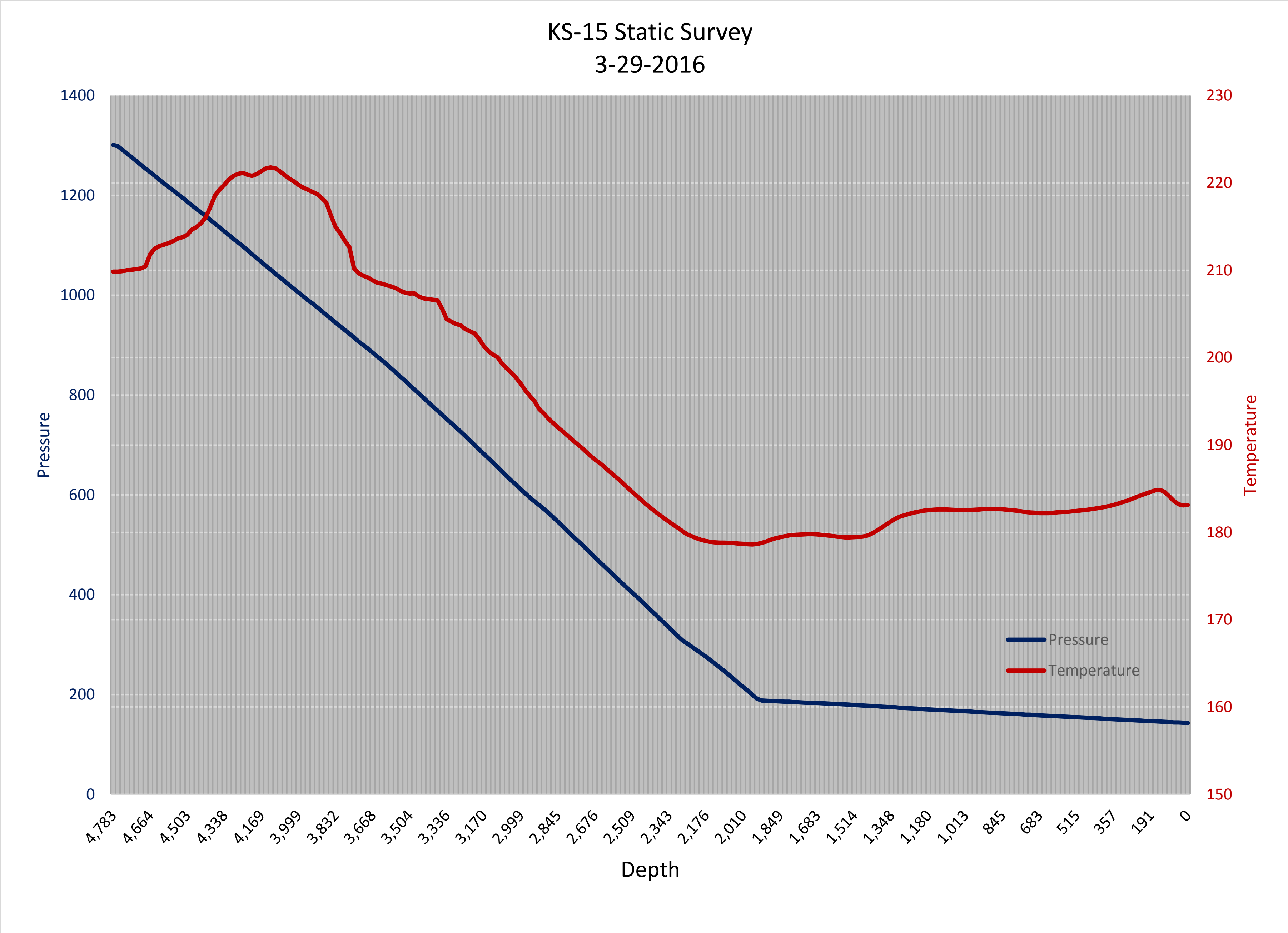

KS-15 Static Survey
3-29-2016
Pressure
1400
1200
1000
800
600
400
200
0
Temperature
230
220
210
200
190
180
170
160
150
Depth
4,783
4,664
4,503
4,338
4,169
3,999
3,832
3,668
3,504
3,336
3,170
2,999
2,845
2,676
2,509
2,343
2,176
2,010
1,849
1,683
1,514
1,348
1,180
1,013
845
683
515
357
191
0
Pressure
Temperature

Table C-2

RESERVOIR PRESSURE DATA OF EXISTING INJECTION WELLS

SINCE PROJECT START-UP

WELL	Static Reservoir Pressure Before Project Startup		1995-1996 Shut-In Pressure Data			2004-2005 Shut-In Pressure Data*			2009-2010 Shut-In Pressure Data**			2015 Shut-In Pressure Data			2019 Shut-In Pressure Data			Well Avg.	WELL
	Date	Pressure (psig)	Date	Hours Shut-in	Pressure (psig)	Date	Hours Shut-in	Pressure (psig)	Date	Hours Shut-in	Pressure (psig)	Date	Hours Shut-in	Pressure (psig)	Date	Hours Shut-in	Pressure (psig)	Pressure (psig)	
KS-1A	03/20/92	2355.6	10/27/95	34	2457.4	10/22/04	36	2436	12/08/09	12	2433	04/10/15	12	2323	03/18/19	7656	2255	2376.7	KS-1A
KS-3	01/31/91	2390.1	10/31/95	34	2327	10/18/04	36	2446	12/10/09	12	2365	04/29/15	12	2257	03/15/19	7584	2231	2336.0	KS-3
KS-4	01/13/93	2306	06/24/96	39	2387.6	10/20/04	36	2449	NA***									2380.9	KS-4
KS-11	10/24/04	2323				10/24/04	36	2323	01/14/10	12	2312	04/28/15	12	2288	NA****			2311.5	KS-11
KS-13	11/30/05	2419				11/30/05	36	2419	12/28/09	12	2354	05/01/15	12	2308	03/13/19	24	2260	2352.0	KS-13
KS-15												06/06/13	NA	1544	03/20/19	7704	2246	1895.0	KS-15
Avg.		2358.7			2390.7			2414.6			2366.0			2294.0			2248.7	2364.8	Avg.
Avg. w/15		NA			NA			NA			NA			2144.0			2248.1	2144.0	Avg. w/15

Pressures are corrected to datum at -5,880 feet MSL (6,500 feet vertical below ground level)

* Shut-in pressure data calculated from 36-hour shut-in surveys in 2004.
** Shut-in pressure data calculated from 12-hour shut-in surveys from 2008
*** KS-4 Converted to Production 11-30-06, Plugged and Abandoned 5-19-10
**** KS-11 wellhead was damaged by lava and has not been repaired yet.

ATTACHMENT C-1 – RECORDS OF PLUGGING AND ABANDONMENT

KS-1 P & A HISTORY

LOCATION: 8942' N & 9838' E OF THE KALIU BENCHMARK
ELEVATION: 613' ABOVE MSL. ALL DEPTHS RKB, 25' ABOVE G.L.

05/01/93 Depth 7290'
Moved in and rigged up Parker Drilling Company Rig #231.

05/07/93 Depth 7290'
Rigged up. Rig on day rate at 2300 hours. Function tested blow out prevention equipment. Ran in hole picking up 3½" drill pipe.

05/08/93 Depth 7290'
Ran in hole picking up 3½" drill pipe to top of cement plug at 1721'. Attempted to fill hole with water. Water level remaining at 650'. Rigged up Halliburton and pumped 10 barrels of water ahead followed by 50 cubic feet of Hawaiian cement premixed with 40% SSA-1, 0.65% CFR-3 and 3% calcium chloride. Displaced with 6 barrels of water. Pulled out of hole and waited on cement 4 hours. Ran in hole to top of cement at 1497'. Pulled out of hole. Removed blowout prevention equipment and expansion spool. Removed bit guide, packing and casing centralizer. Inspected cement around 7" casing. Unable to pull 7" casing. Reinstalled expansion spool and blowout prevention equipment. Halliburton pumped from surface 20 barrels of water ahead followed by 200 cubic feet Hawaiian cement premixed with 40% SSA-1, 0.65% CFR-3 Displaced with 5 barrels water. Shut in wellhead pressure was -4 psi (vacuum). Waited on cement.

05/09/93 Depth 7290'
Ran in hole with open ended drill pipe to 1497'. Pulled out of hole. Fluid level at 350'. Pumped 50 barrels of water. Fluid level at 240'. Closed blind rams. Halliburton pumped from surface 3 barrels of water and 250 ft^3 of Hawaiian cement premixed 40% SSA-1, 0.65% CFR-3 and 2% $CACL_2$. Displaced with 3 barrels of water. Waited on cement. Ran in hole with open ended drill pipe to 1497'. Pulled out of hole. Fluid level at 240'. Filled hole with 10 barrels of water. Waited on cement. Closed blind rams. Howco pressure tested casing to 1500 psi, pressure bled to 0 in 15 minutes. Ran in hole with open ended drill pipe to 218'. Howco spotted 25 cubic feet Hawaiian cement with 40% SSA-1, 0.65% CFR-3 and 2% $CaCl_2$ from 218' to 102'. Pulled out of hole. Closed blind rams and squeezed 4 barrels of cement with maximum pressure of 1500 psi and final pressure 900 psi. Pressure bled to 20 psi in 15 minutes. Shut in well. Waited on cement.

05/10/92 Depth 7290'

Pressure tested casing to 500 psi. Serviced leaks in 3" wing valve and 10" master valve. Pressure tested blow out prevention equipment and plug to 1500 psi, OK. Made up drilling assembly and ran in hole. Cleaned out cement from 223' to 324'. Ran in hole to 1497'. Tested casing to 500 psi surface pressure, OK. Cleaned out cement from 1497' to 1632'.

05/11/93 Depth 7290'

Cleaned out cement from 1632' to 1721'. Circulated hole clean with full returns. Performed casing integrity test to 500 psi surface pressure. Pressure bled off in 5 minutes. Tripped for open ended drill pipe to 1716'. Halliburton mixed and pumped 50 cubic feet of Hawaiian cement premixed with 40% SSA-1, 0.65% CFR-3 and 3% $CACL_2$. Displaced cement with 9 barrels of water and pulled 7 stands of drill pipe. Attempted to squeeze 7 barrels away. Pulled out of hole and waited on cement. Ran in hole and tagged top of cement at 1312' (calculated fill with no cement squeezed out). Pulled open ended drill pipe to 529'. Halliburton mixed and pumped 50 cubic feet of Hawaiian cement premixed with 40% SSA-1, 0.65% CFR-3 and 3% $CACL_2$. Displaced cement with 1 barrel of water. Pulled out of hole. Closed blind rams and squeezed 3 barrels away at 500 psi surface pressure. Waited on cement.

05/12/93 Depth 7290'

Mixed 10.5 PPG kill mud with cotton seed hulls. Cleaned out cement stringers from 371' to 500'. Cleaned out solid cement from 500' to 731'. Cleaned out cement from 1503' to 1742'. Circulated hole clean. Reconfigured pipe rams for snubbing operation. Rigged up power swivel.

05/13/93 Depth 7290'

Rigged up and tested power swivel. Cleaned out cement from 1742' to 1901' with power swivel and 10.5 PPG mud. Hit collapsed casing at 1901'. Tripped for 6" concave mill. Unable to pass 233' with mill. Tripped for 3⅞" concave mill. Milled pilot hole from 1901' to 1931'. Tripped for 5⅞" tapered mill. Cleaned out collapsing casing and pilot hole from 1811' to 1901'.

05/14/93 Depth 7290'

Milled out tight spot in 9⅝" casing from 1901' to 1903' with power swivel and 10.5 PPG mud. Cleaned out cement to 1911' with 5⅞" tapered mill. Tripped for 5⅞" bit. Cleaned out cement from 1911' to 2312' with power swivel and 10.5 PPG mud. Ran in hole to top of 7" perforated liner at 3874'. Circulated hole. Had sulphur water at surface with 75 ppm H_2S and 14,000 ppm CO_2. Shut in well and rigged up to abate using Halliburton to pump caustic through wing valve at ⅛ BPM. Circulated hole through choke. Opened rams and circulated hole clean. Tripped for open ended drill pipe and circulated hole. Had no H_2S at surface.

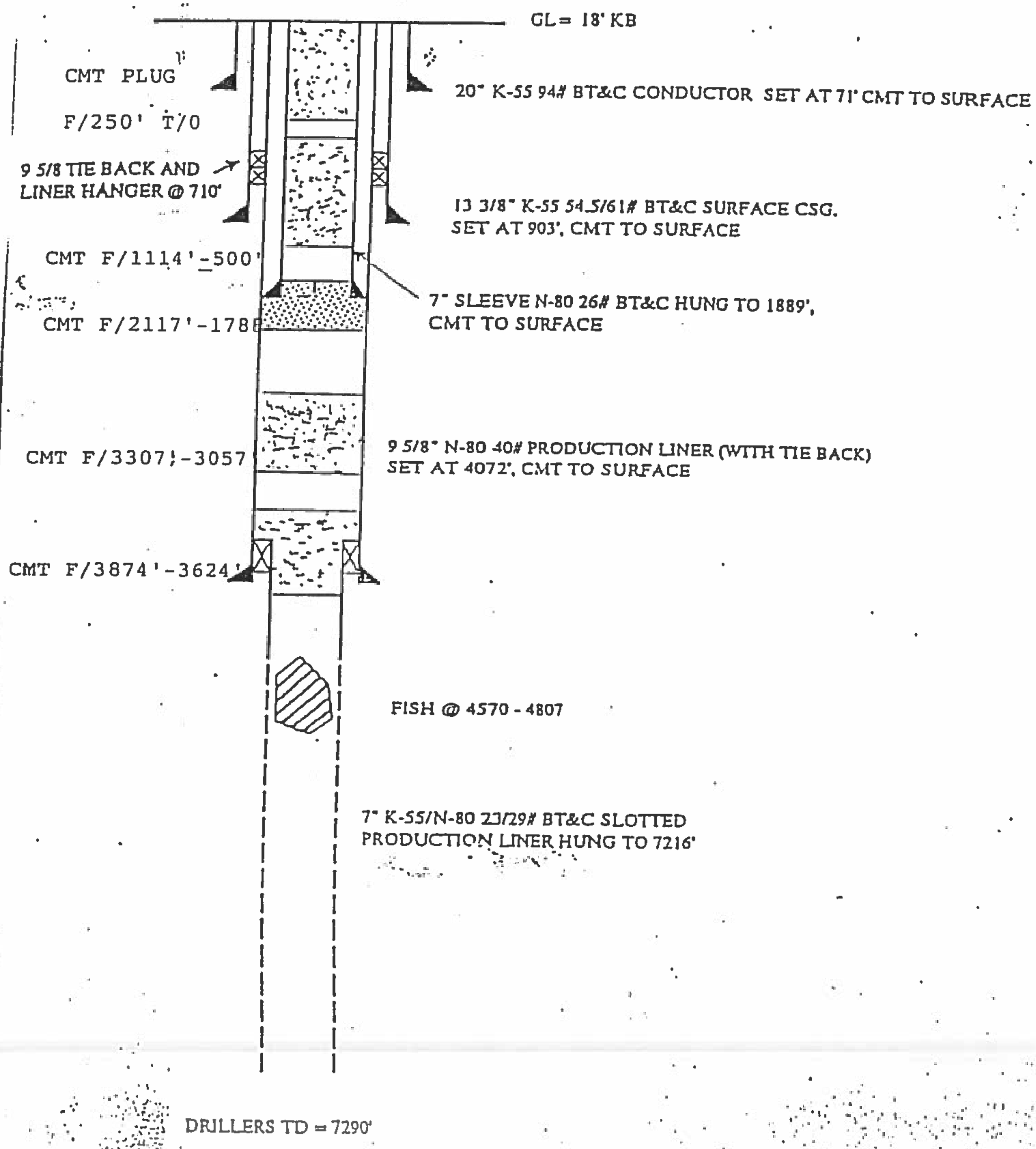
05/15/93 P.B. Depth 3307'
With open ended drill pipe at 3874', Halliburton pumped 5 barrels of water ahead followed by 106 cubic feet of Hawaiian cement premixed with 40% SSA-1 and 0.65% CFR-3. Displaced cement with 5 barrels of water and 22 barrels of mud. Pulled 7 stands. Shut well in and squeezed 2 barrels down hole at 1200 psi surface pressure. Waited on cement. Conditioned mud in storage tanks. Ran in hole to solid plug of barite and gel (calcium alumna silicate) at 3307'. Plugged pipe. Tripped to unplug 3½" saw tooth single. Circulated and conditioned mud at 3307'. Ran pressure and temperature survey to 3290'. Pressure gradient was normal and the temperature at bottom was 187 degrees F.

05/16/93 P.B. Depth 500'
With pipe hung at 3307', Halliburton pumped 5 barrels of water ahead followed by 85 cubic feet of Hawaiian cement premixed with 40% SSA-1, 0.65% CFR-3 and 3% calcium chloride. Displaced cement with 5 barrels of water and 19.5 barrels of mud. Pulled drill pipe to 2117'. Halliburton pumped 86 cubic feet of Hawaiian cement premixed with 40% SSA-1, 0.65% CFR-3 and 3% calcium chloride. Displaced cement with 10 barrels of mud. Laid down excess drill pipe. Waited on cement. Tagged top of cement at 1788'. Pulled to 1114'. Halliburton pumped 2 barrels of water ahead followed by 129 cubic feet of Hawaiian cement premixed with 40% SSA-1, 0.65% CFR-3 and 3% calcium chloride. Displaced cement with ½ barrel water and 1½ barrels of mud. Laid down drill pipe and tools. Waited on cement. Tagged top of cement at 500'. All plug settings witnessed by Eric Tanaka, DLNR.

05/17/93 P.B. Depth Surface
Nippled down BOPE and master valve. Ran in hole with 3½" drill pipe to 250'. Halliburton pumped 50 cubic feet of Hawaiian cement premixed with 40% SSA-1, 0.65% CFR-3 and 3% calcium chloride. Had good cement returns to surface. Pulled out of hole. Halliburton filled well bore with Hawaiian cement premixed with 40% SSA-1, 0.65% CFR-3 and 3% $CaCl_2$ slurry to surface. Nippled down equipment and cleaned mud tanks. Released rig at 2400 hours. The P & A will be completed by cutting off the wellhead and welding a plate on the casing and removing then backfilling the cellar.

P+A

PGV WELL KS-11



KS-02 P & A HISTORY

LOCATION:	9,589' N & 10,974' E. OF THE KALIU BENCHMARK.
ELEVATION:	712' ABOVE MSL. ALL DEPTHS FROM RKB, 25' ABOVE G.L.

05/23/93 Depth 8005'
Moved in and rigged up Parker Drilling Company Rig #231 on KS-2.

05/24/93 Depth 8005'
Rig on day rate at 0000 hours. Function tested blow out preventer equipment to 1500 psi, OK. Rigged up and ran spinner survey to 2984'. Survey showed no flow, indicating no Leaks. Pressure tested 9⅝" casing to 1600 psi surface pressure. Had very slow bleed off through a leaking wing valve. Tripped in hole with 8½" bit to the top of cement at 3001'. Conditioned mud in pits to 9.4 ppg.

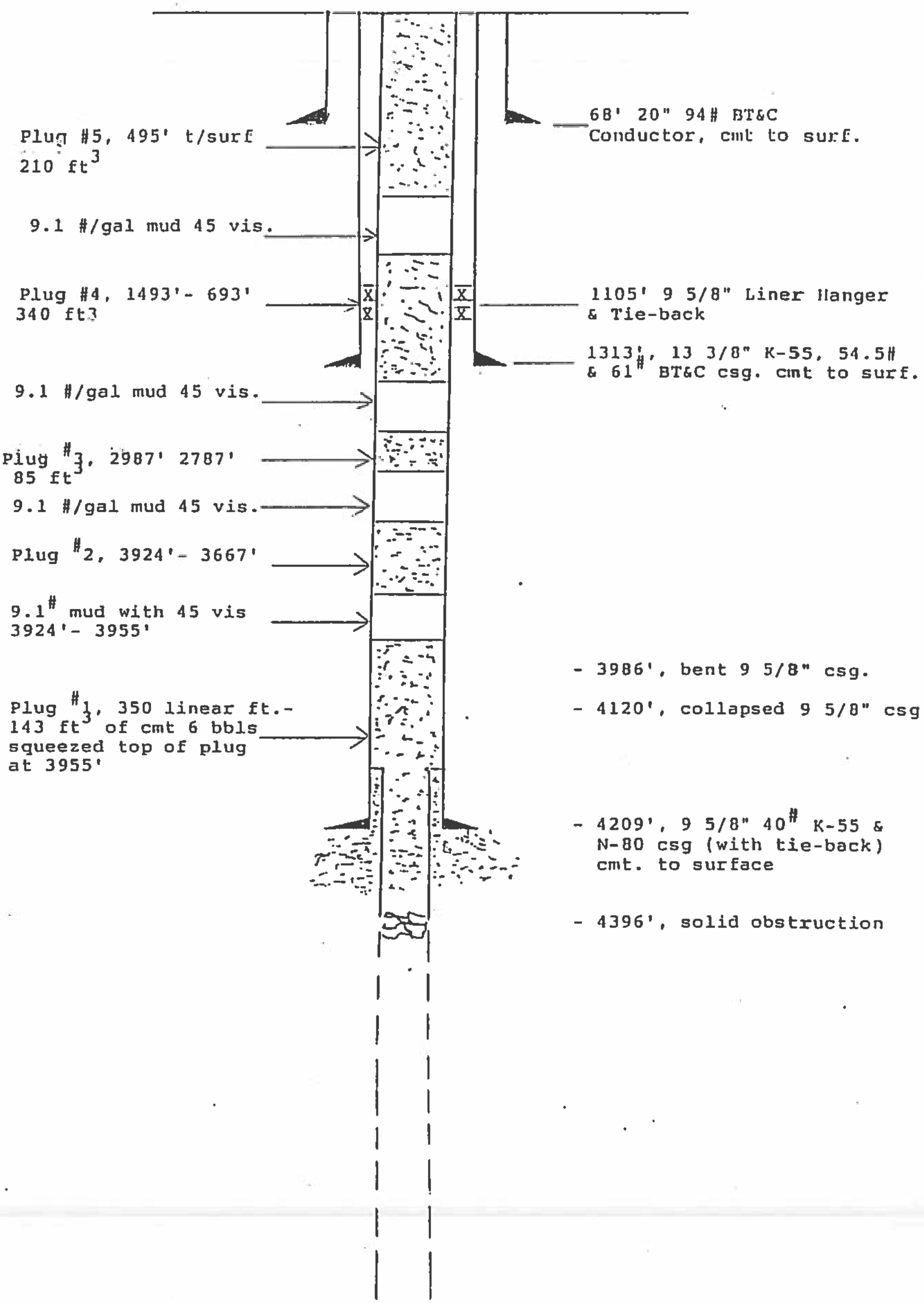
05/25/93 P.B. Depth 3955'
Displaced 180 barrels water out of hole with 9.4 ppg mud. Had 40,000 ppm hydrogen, 500 ppm CO_2 and no H_2S gas in the water. Cleaned out cement from 3001' to 3180'. Ran in hole to 3258'. Closed in well and displaced water out of casing into formation with mud from surface. Tripped in hole to 3986' and circulated through choke. Monitored gasses and abated H_2S with ⅛ BPM caustic pumped by Howco into wing valve. Tripped for open ended drill pipe. Hit obstruction at 4120'. Circulated through choke. Monitored gasses, had no H_2S and 400 ppm CO_2. Rigged up Howco. Hung pipe at 4110'. Howco pumped 10 barrels water followed by 143 ft^3 Hawaiian cement premixed 40% SSA-1 and 0.65% CFR-3. Displaced with 2 barrels water and 20 barrels mud. Tripped out of hole 10 stands and squeezed away 11¼ barrels cement. Held 800 psi final squeeze pressure for 2 hours.

05/26/93 P.B. Depth Surface
Ran in hole with open ended drill pipe to the top of cement at 3955'. Rigged up and ran pressure temperature survey to 3910'. Pressure was 2065 psia and temperature was 208°F. Had no cross flow or up flow. Circulated at 3995'. Halliburton pumped 10 barrels water followed by 110 cubic feet of Hawaiian cement premixed with 40% SSA-1 and 0.65% CFR-3. Displaced with 2 barrels of water and 20 barrels of mud. Pulled out of hole to 3267'. Waited on cement 4 hours. Ran in hole to top of cement at 3667'. Pulled to 2987'. Halliburton pumped 10 barrels of water ahead followed by 85 cubic feet Hawaiian cement premixed with 40% SSA-1, and 0.65% CFR-3. Displaced

cement with 2 barrels water and 6 barrels mud. Pulled out of hole to 1493'. Waited on cement. Tagged top of cement at 2789'with wire line. Through open ended drill pipe at 1493', Halliburton pumped 10 barrels of water ahead followed by 340 cubic feet of Hawaiian cement premixed with 40% SSA-1 and 0.65% CFR-3. Displaced cement with 2 barrels of water and 2 barrels of mud. Pulled out of hole to 493'. Waited on cement. Tagged top of cement at 691' with wire line. Through pipe hung at 493' Halliburton pumped 10 barrels of water ahead followed by 210 cubic feet of Hawaiian cement premixed with 40% SSA-1 and 0.65% CFR-3. Displaced cement with 1 barrel of water. Pulled out of hole. Waited on cement Laid down drill pipe and tools. Nippled down Blowout prevention equipment.

05/27/93 P.B. Depth Surface
Nippled down and cleaned pits. Released rig at 1200 hours 5/27/93. The P & A will be completed by cutting off the casing head, welding a plate on the casing and removing then backfilling the cellar.

KS-02 P & A
KB = 25'



Plug #5, 495' t/surf
210 ft^3
9.1 #/gal mud 45 vis.
Plug #4, 1493'- 693'
340 ft3
9.1 #/gal mud 45 vis.
Plug #3, 2987' 2787'
85 ft^3
9.1 #/gal mud 45 vis.
Plug #2, 3924'- 3667'
9.1# mud with 45 vis
3924'- 3955'
Plug #1, 350 linear ft.-
143 ft^3 of cmt 6 bbls
squeezed top of plug
at 3955'
68' 20" 94# BT&C
Conductor, cmt to surf.
1105' 9 5/8" Liner Hanger
& Tie-back
1313', 13 3/8" K-55, 54.5#
& 61# BT&C csg. cmt to surf.
- 3986', bent 9 5/8" csg.
- 4120', collapsed 9 5/8" csg.
- 4209', 9 5/8" 40# K-55 &
N-80 csg (with tie-back)
cmt. to surface
- 4396', solid obstruction

KS-07 WORKOVER HISTORY

LOCATION: 8367' N AND 10728' E OF THE KALIU BENCHMARK
ELEVATION: 620' ABOVE MSL. ALL DEPTHS PKB, 25' ABOVE G.L.

03/15/93 Depth 1678'
Moved in and rigged up Cudd 600 hydraulic unit and associated equipment. Tested blowout prevention equipment to 2000 psi with test plug and tested casing to 350 psi surface pressure. Test witnessed and approved by E. Tanaka, DLNR. Ran in hole with 12¼" bottom hole assembly to top of cement at 710'. Held safety meeting and tested H_2S monitors. Cleaned out cement from 710' to 755'. Secured well for night.

03/16/93 Depth 1678'
Cleaned out cement from 755' to 975'. Secured well for night.

03/17/93 Depth 1678'
Cleaned out cement from 975' to 1068'. Had increasing amounts of carbonized lost circulation material in samples, CO_2 increased from 500 ppm to 1000 ppm. Cement quality had deteriorated. Cement was powdery and soft. Pulled to shoe. Pressured up well bore to 300 psi surface pressure with no leak off. Pulled out of hole. Secured well for night.

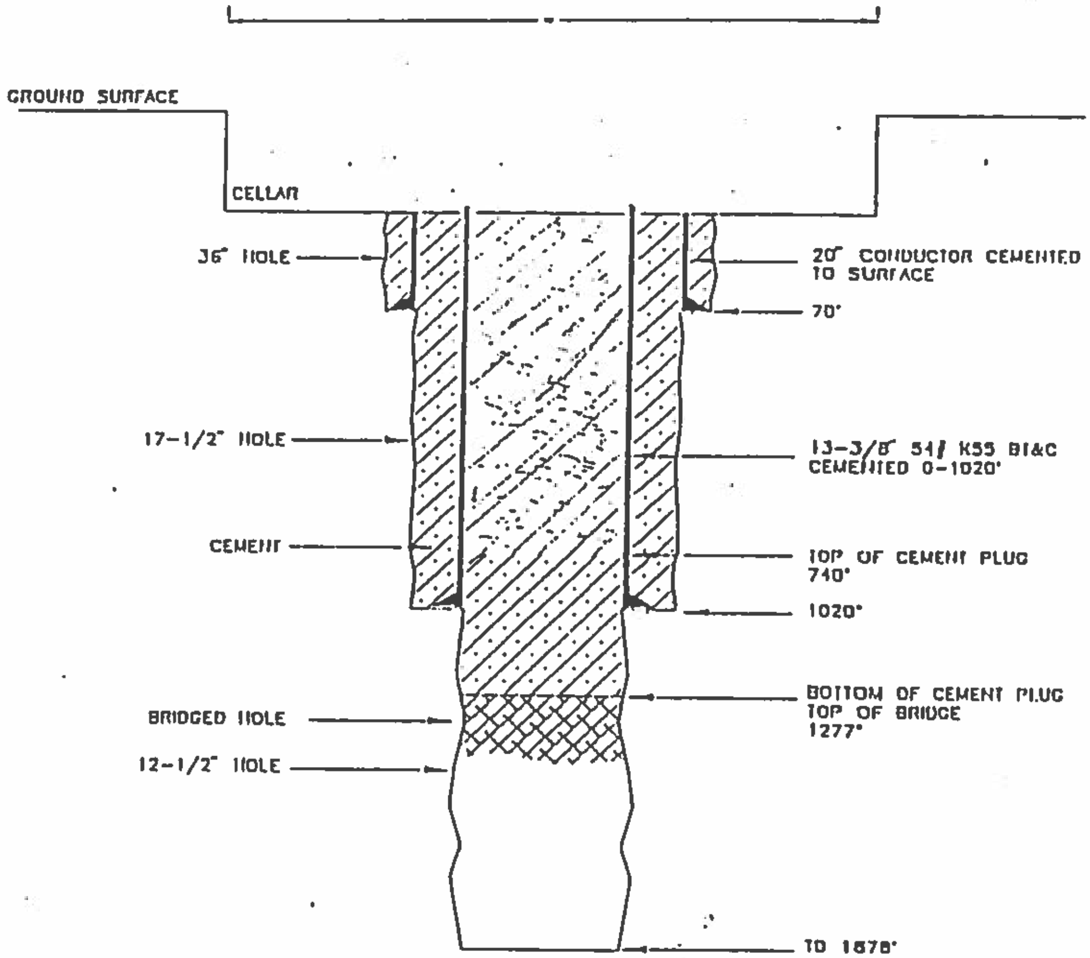
03/18/93 Plug Back Depth 900'
Laid down drill collars and tools. Ran in hole with open ended drill pipe to 1058'. Washed out fill to 1068'. Howco displaced a balanced plug consisting of 150 ft^3 Hawaiian cement premixed with 40% SSA-1 and 0.65% CFR-3. Pulled up to 700'. Squeezed away 23 ft^3 of cement at 550 psi surface pressure. Tripped for 13⅜" EZSV bridge plug. Secured well for night.

03/19/93 Plug Back Depth 490'
Circulated hole clean. Checked CO_2, had normal readings. Tagged top of cement at 900'. Set 13⅜" EZSV at 890'. Tested cement plug below packer to 500 psi surface pressure, OK. Pulled out of packer. Tested casing above packer to 500 psi surface pressure, OK. Howco displaced a balanced plug consisting of 250 ft^3 Hawaiian cement premixed with 40% SSA-1 0.65% CFR-3. Theoretical top of cement at 490'. Pulled out of hole laying down drill pipe. Secured well. Prepared Cudd unit for move to KS-09. Suspended operations.

03/20/93 to 04/02/93 No activity.

04/03/93 Depth - Plugged back to surface
Rigged up crane. Installed work platform on casing head. Ran in hole with 2⅞" tubing to top of cement at 465' ground level (490' KB). Hung tubing at 463' ground level. Howco cemented as follows: Pumped 3 barrels water followed by 287 ft^3 neat Hawaiian cement plus 150 ft^3 Hawaiian cement premixed 40% SSA-1 and 0.65% CFR-3. Did not displace. Had good cement returns to surface. Pulled out of hole. Plug setting witnessed by E. Tanaka, DLNR. Rigged down. Waited on cement.

04/04/93 Depth Plugged Back to Surface
Cut off wellhead and welded plate to cover top of casing. Plug and Abandon will be completed by removing cellar to 6' below ground level and back filling to ground level.



PUNA GEOTHERMAL VENTURE

PLUGGED &
ABANDONED
4/4/93

DATE 12/23/92		REV. 1
BY W. TEPLOW	FILE: PGV\ KS7SUSP.DWG	FIGURE NO. 6

KS-8 REMEDIAL/P & A HISTORY

LOCATION: 8879' N & 10568' E OF THE KALIU BENCHMARK
ELEVATION: 629' ABOVE MSL. ALL DEPTHS RKB, 25' ABOVE G.L.

11/3/92 through 11/4/92

REMARKS: A meeting was held on 11/03/92 at 0900 11/3/93 hours and it was decided to kill and plug KS-8 until further diagnostics could be performed. Men and equipment were mobilized into position and the kill procedure was implemented as follows. Halliburton started pumping water at 1/4 barrel per minute with 1800 psi for one hour. Wellhead pressure dropped to 1500 psi during that time. During the second hour the pump rate was increased to 1/2 barrel per minute and the pressure slowly dropped to 1300 psi. Pump rate was then increased to 3/4 barrels per minute for one hour and pressure continued to drop to 1000 psi. Rate was increased to 1 barrel per minute for the 4th hour and the wellhead pressure dropped to 700 psi. The pump rate was increased to 3 barrels per minute at 700 psi pressure for 30 minutes. Halliburton then pumped 100 barrels of 13.2 ppg mud with 10 ppb LCM. The mud was immediately followed by cement. HOWCO pumped 600 cubic feet Hawaiian cement premixed 40% SSA-1, 2% CFR-3, 1.75% Halad 22-A and 0.75% LWL. Displaced cement with 116 barrels of 13.2 ppg mud with 10 ppb LCM and 10 barrels water. Final displacement pressure was 0 psi. CIP at 0300 hours, November 4, 1992. Well temporarily suspended. All operations observed by Eric Tanaka of DLNR.

11/5/92 Rigged and ran sinker bars to 400'. Unable to go deeper due to the viscous dense mud in the well. Suspended operations.

11/06/92 to 11/11/92 No activity.

04/12/93 Depth 3488'
Moved Parker rig #231 from KS-10 to KS-08 for plug and abandonment. Rigged up.

04/13/93 Depth 3488'
Rig on day rate at 0000 hours. Ran in hole to 550' with 8½" bit. Circulated hole clean. Washed hole from 550' to obstruction in well bore at 586'. Tripped for 6" bit Unable to pass obstruction at 586'. Tripped for 3½" saw tooth single. Unable to pass obstruction at 586'. Tripped for 6½" impression block. Tagged obstruction and

pulled out of hole. Impression block indicated collapsed 9⅝" casing. Ran in hole with open ended 2⅜" drill pipe to obstruction at 586'. Unable to pass. Tripped for 1" tubing to 738'. Had no obstruction. Tripped for 2" mill. Encountered obstruction at 647'. Pulled out of hole. Ran 1⅞" sinker bar on wireline. Unable to pass obstruction at 586'. Ran in hole with 4¼" tapered mill.

04/14/93 Depth 3488'
Milled on 9⅝" liner with 4¼" tapered mill from 586' to 587'. Tripped for tapered 4¼" mill. Milled on 9⅝" liner at 587'. Tripped for 1" tubing. Found obstruction at 586'. Tripped for 6" concave junk mill. Cleaned up mud rings and tight casing from 512' to 587'. Milled on 9⅝" casing from 587' to 589'.

04/15/93 Depth 3488'
Milled with 6" concave mill from 589' to 594'. Circulated hole clean. Tripped for 1" tubing. Circulated bottoms up at 585' and 1381'. Pulled out of hole. Rigged up and ran temperature-pressure survey to 1351'. Maximum temperature 90°F. Ran minimum inside diameter tool to 1350'. Log indicated damaged 9⅝" casing from 550' to 600' with minimum ID of 4½" at 590'. Ran in hole with 8½" junk mill. Milled on 9⅝" casing from 590' to 596'. Ran in hole.

04/16/93 Depth 3488'
Cleaned out birds nest from 1350' to top of liner hanger at 1381'. Circulated hole clean. Tripped for 4¼" junk mill. Circulated hole clean at 1395'. Pulled out of hole. Rigged up and ran 31 joints of 7", 29#, L-80, SLHC and buttress casing, with bottom of casing at 1239'. Howco mixed and pumped 300 ft^3 Hawaiian cement premixed 40% SSA-1, 0.65% CFR-3, 3% gel and 2% $CACL_2$. Displaced with 238 ft^3 of water. Had good returns to surface. Bled back 8½ ft^3 of displacement fluid and shut in 7" casing at surface. Waited on cement. Monitored 7" casing pressure.

04/17/93 Depth 3488'
Backed off two landing joints of 7" casing at 77'. Ran in hole with 6" bit. Cleaned out cement from 1052' to 1156'. Tested casing to 2000 psi surface pressure OK. Cleaned out cement from 1156' to 1239' and circulated hole clean. Washed 9⅝" casing from 1239' to 1394' and swept hole clean. Tripped for 4¼" junk mill.

04/18/93 Depth 3488'
Cleaned out 5" casing with 4¼" junk mill from 1394' to 1605'. Pulled out of hole. Ran sinker bar (1⅞" OD bar). Sinker bar stopped at 1609'. Ran in hole with 4¼" junk

mill. Attempted to clean out 5" casing at 1605' with no progress. Tripped to change mills. Milled on junk at 1605'.

04/19/93 Depth 3488'
Milled on junk at 1604'. Tripped for open ended drill pipe. Reverse circulated hole clean. Tripped for 4" junk mill. Milled on junk at 1605'. Had no drill off, indicating that junk was turning under mill. Tripped for open ended drill pipe to 1605'. Howco displaced 6 ft^3 Hawaiian cement with 40% SSA-1, 0.65% CFR-3 and 2% $CACL_2$, to consolidate loose junk. Tripped for 4" mill tooth bit. Waited on cement. Cleaned out cement from 1514' to 1605'. Worked bit on junk. Washed and worked inside of 5" casing from 1605' to 1667'.

04/20/93 Depth 3488'
Tripped for 4" junk mill. Milled on junk from 1667' to 1668'. Pulled out of hole. Secured rig and well for flow test of KS-09. Remained shut down for 8 hours. Ran in hole with open ended drill pipe to 1668'. Howco displaced 6 ft^3 Hawaiian cement with 40% SSA-1, 0.65% CFR-3 and 2% $CACL_2$ to consolidate loose junk. Tripped for bit. Waited on cement.

04/21/93 Depth 3488'
Cleaned out hard cement from 1588' to 1668'. Pulled out of hole and made up 4" concave mill. Ran in hole and milled on 5" casing at 1668'. Tripped for 4" tapered mill. Milled and reamed 5" casing from 1668' to 1807'.

04/22/93 Depth 3488'
Pulled out of hole. Left mill, bit sub and twisted off float sub in hole, length of fish 4.73'. Tripped in hole to top of fish at 1803'. Pulled out of hole. Secured well and waited on slim shot grapple.

04/23/93 Depth 3488'
Waited on slim hole overshot. Ran in hole with 3⅝" grapple in overshot. Unable to engage fish. Tripped to clean out overshot. Engaged fish at 1803. Pulled out of hole with fish to tight spot at 1668'. Attempted to work through tight spot and dropped fish. Tripped to replace broken grapple.

04/24/93 Depth 3488'
Unable to work over fish with 3½" grapple. Tripped for 4" magnet, recovered metal shavings. Tripped for stiff milling assembly. Encountered no obstructions to 1803'. Circulated hole clean. Pulled out of hole. Secured well. Waited on fishing tools.

04/25/93 Depth 3488'
Reran magnet. Recovered broken piece of grapple. Waited on fishing tools. Ran in hole with 3¾" grapple in overshot to 1803'. Worked over end engaged fish. Pulled out of hole. Pulled through tight spot at 1668' with 4,000# drag. Recovered fish. Ran in hole with milling assembly consisting of 3¾" concave mill and 2 - 4¼" string mills. Milled from 1807' to 1808'. Cleaned out from 1808' to 1965'.

04/26/93 PB Depth 2159'
Cleaned out from 1965' to 2621' with milling assembly. Pulled out of hole. Ran temperature survey to 2617'. Maximum temperature was 324°F, indicating no cross flow. Attempted to run 3 arm caliper log with no success. Ran in hole with open ended drill pipe to 2621' and circulated bottoms up. Howco 22 ft^3 Hawaiian cement premixed 40% SSA-1 and 0.65% CFR-3. Displaced with 12.5 barrels water. Pulled out of hole to 2343'. Howco pumped 22 ft^3 Hawaiian cement premixed 40% premixed SSA-1, 0.65% CFR-3 and 3% $CaCl_2$. Displaced with 10.7 barrels water. Pulled out of hole to 2163'. Circulated hole clean. Pulled out of hole. Waited on cement. Ran in hole to cement top at 2159'.

04/27/93 PB Depth 2159'
Tripped for 5" RTTS. Set RTTS packer at 1400'. Tested 5" casing below packer to 500 psi, O.K. Tested annulus above packer to 500 psi, had small leak off in annulus above packer. Released packer. Tripped for open ended drill pipe to liner top at 1381'. Rigged up wireline unit. Waited on permit to transport and use explosives to perforate.

04/28/93 PB Depth 2159'
Waited on permits. Rigged up lubricator and perforated with 8 holes from 2133' to 2135'. Attempted to reperforate from 2143' to 2145', perforating charges misfired. Rigged down loggers. Tripped for 5" RTTS. Set 5" RTTS at 1417'. Tested annulus above packer to 500 psi, O.K. Tested 5" casing. Perforations broke down at 1000 psi. Pumped 2 bpm water at 1600 psi through perforations. Tripped for 7" EZSV.

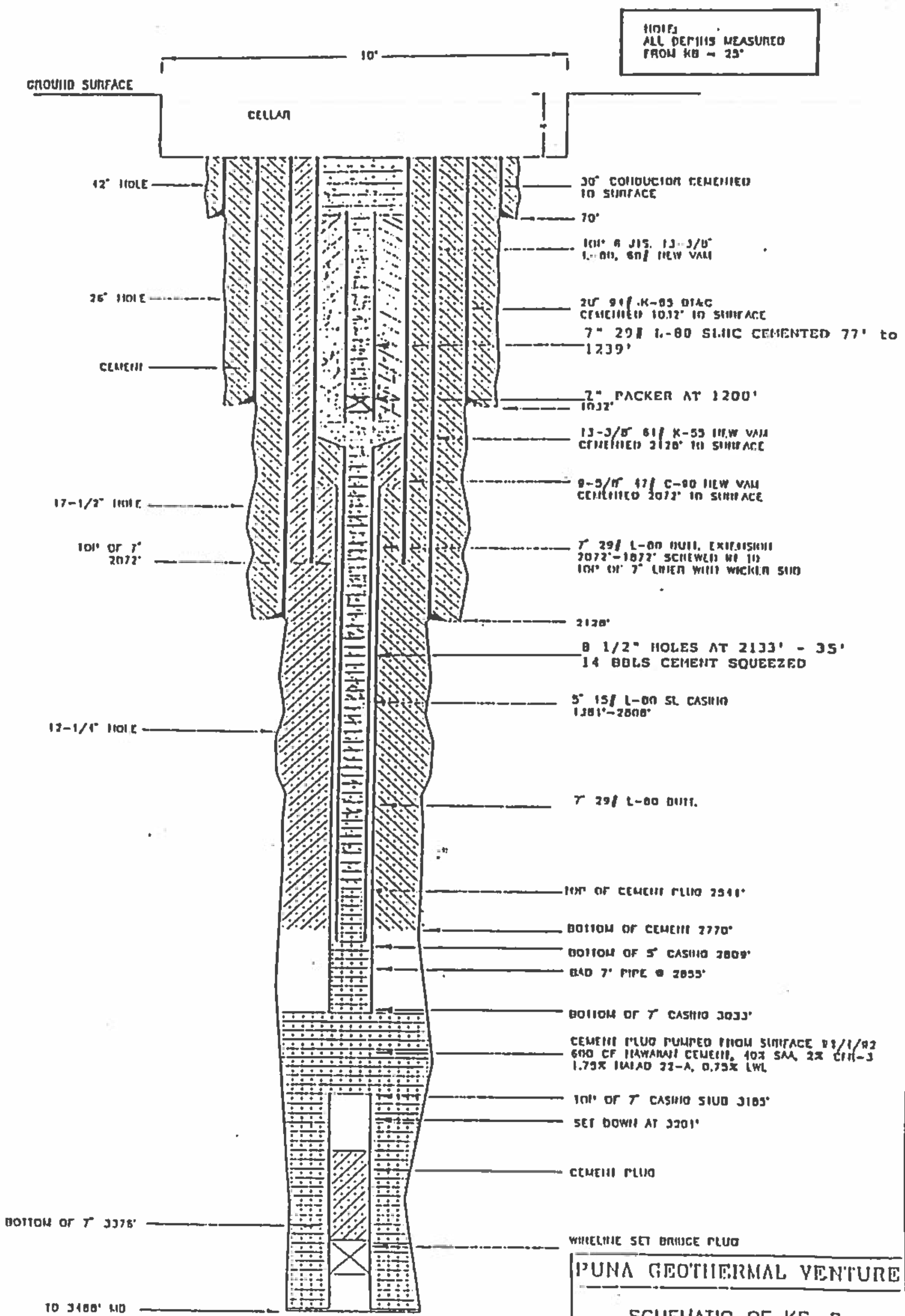
04/29/93 PB Depth 101'
Set EZSV packer at 1200'. Howco pumped through packer 50 bbls Hawaiian cement premixed 40% SSA-1 and 0.65% CFR-3. Squeezed 16 barrels into formation through perforations from 2133' to 2135' at 2500 psi final squeeze pressure. Pulled out of EZSV. Howco mixed and pumped an additional 13 bbls Hawaiian cement with 40% SSA-1 and 0.65% CFR-3. Displaced with 7 barrels water. Pulled out of hole to

820'. Howco mixed and pumped 13 bbls of Hawaiian cement with 40% SSA-1 and 0.65% CFR-3. Displaced with 3 barrels water. Pulled out of hole to 475'. Howco mixed and pumped 15 bbls Hawaiian cement with 40% SSA-1 and 0.65% CFR-3. Displaced with 1 barrel water. Pulled out of hole to 90' and circulated cement out of hole. Waited on cement. Laid down drill pipe. Cleaned mud pits. Tagged top of cement at 101' with wireline. Nippled down blow out prevention equipment.

04/30/93 PB Depth 101'
Nippled down blow out prevention equipment. Cut off well head. Rigged down. Released rig at 1000 hours 4/30/93 for move to KS-1.

05/01/93 PB Depth Surface
Cut off casing head. Filled casing to surface with 1 yard ready mix concrete. P & A will be completed by welding plate on casing and removing then back filling cellar.

P & A



PUNA GEOTHERMAL VENTURE

SCHEMATIC OF KS-8
AS OF 11/4/92

DATE 12/23/92		REV. 1
BY W. TEPLOW		FIGURE NO. 7

Geothermal Resource Group
TAPPING THE EARTH'S ENERGY

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Kapoho State 4 Plug and Abandon – Final Report

For

Puna Geothermal Venture
14-3860 Kapoho Pahoa Road
Pahoa, Hawaii 96778

By

Wm. M. Rickard
Geothermal Resource Group, Inc.
June, 2010

Contents

Geothermal Resource Group

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Well History Report

Well Summary Report

CONFIDENTIAL - G R G Inc

Well ID: KS-4 RD CO 2 | Well Name: KS-4RD Clean Out

Field: Kilauea East Rift Zone | County: Hawaii State: HI Country: United States

Operator: Puna geothermal Venture | Working Interest:

AFE Nos: KS-4 RD CO 2

API No: | Spud Date: 21-May-10

Location: 9360.90' E and 8289.03' N of the Kaliu BM, Kapoho, Puna District

Reports for 00:00 on date shown

19-May-10 Current Depth (ft): 0

Comments: Moved rig off KS-6. Moved and set BOPE stack. Moved equipment and rig onto well. Shut down for night.

20-May-10 Current Depth (ft): 0

Comments: Raised derrick and dressed the same. Nippled up and function tested 11"-5M BOPE. Rigged up pumps, lines and floor. Installed 5" liners in rig mud pump. Held pre-spud meeting. Filled pits.

21-May-10 Current Depth (ft): 2,811

Comments: Broke tour. Completed nipple up and tested BOPE to 1000 psi, test approved by Eric Tanaka (DLNR). RIH with 6" BHA, picking up pipe to obstruction at 2811'. Unable to work past metal obstruction. Tripped for concave mill.

22-May-10 Current Depth (ft): 3,874

Comments: RIH with 6" concave mill. Milled thru metal obstruction from 2811' to 2813' with partial returns. RIH. Cleaned out soft scale from 3618' to 3640'. Picked up drill pipe to 4-1/2" liner top at 3784'. Tripped for test packer. Set BOT retrievable packer at 2230'. Attempted to test 9-5/8" by 7" lap with annular closed and had significant leak off. Reset packer at 2215' and tested against pipe rams to 1000 psi with PGV rig pump and had slow leak off on third attempt. RIH and set packer at 2897' (below milled up obstruction). Established establish injection rate above packer of 4 3 bpm at 264 psi. POH.

23-May-10 Current Depth (ft): 3,874

Comments: POH with retrievamatic packer. Picked up and RIH 95 joints of 2-3/8" tubing to 2975' and flushed the tubing. TOH. Made up 3-7/8" bit and 2-7/8" mud motor. TIH to 3341'.

24-May-10 Current Depth (ft): 3,892

Comments: RIH to 3791'. Cleaned out 4-1/2" liner with 3-7/8" PDC bit and 2-7/8" motor to 3892' loosing over 100 barrels per hour. POH due to high pump pressure. Cleaned filter, picked up high torque motor and RIH.

25-May-10 Current Depth (ft): 5,423

Comments: RIH to 3892'. Cleaned out 4-1/2" liner with 3-7/8" PDC bit and 2-7/8" motor to 4208', loosing over 100 barrels per hour. Laid down working pipe and RIH to tight spot. Cleaned out hard scale at 5277' and cleaned out as above to 5423', pumping sweeps every 15 minutes due to cuttings balling up above tools and causing string to pull tight on connections.

26-May-10 Current Depth (ft): 5,509

Comments: Clean out 4-1/2" liner with 3-7/8" PDC bit and 2-7/8" motor from 5423' to 5509' with parial returns. Making very poor progresd, short tripped with no fill. Tripped for conventional 3-3/4" milling BHA.

27-May-10 Current Depth (ft): 5,454

Comments: RIH with 3-3/4" conventional milling BHA. Reamed through bad spot from 5232' to 5236' and RIH to 5441'. Cleaned out in 4-1/2" liner with 3-3/4" mill to 5454' with near full return's. Tripped for OEDP. Laid down tools.

28-May-10 Current Depth (ft): 5,454

Comments: RIH open ended to 5454'. Circulated with 40 bph losses. Pulled above liner top to 3754' and secured well, installing safety valve and closing pipe rams. Kept well dead with water from surface. Waited on approval to P&A. Performed rig maintenance.

29-May-10 Current Depth (ft): 5,454

Comments: Well secured (with pipe at 3754'). Kept dead with water from surface. Waited on approval to plug and abandon. Performed rig maintenance.

30-May-10 Current Depth (ft): 5,454

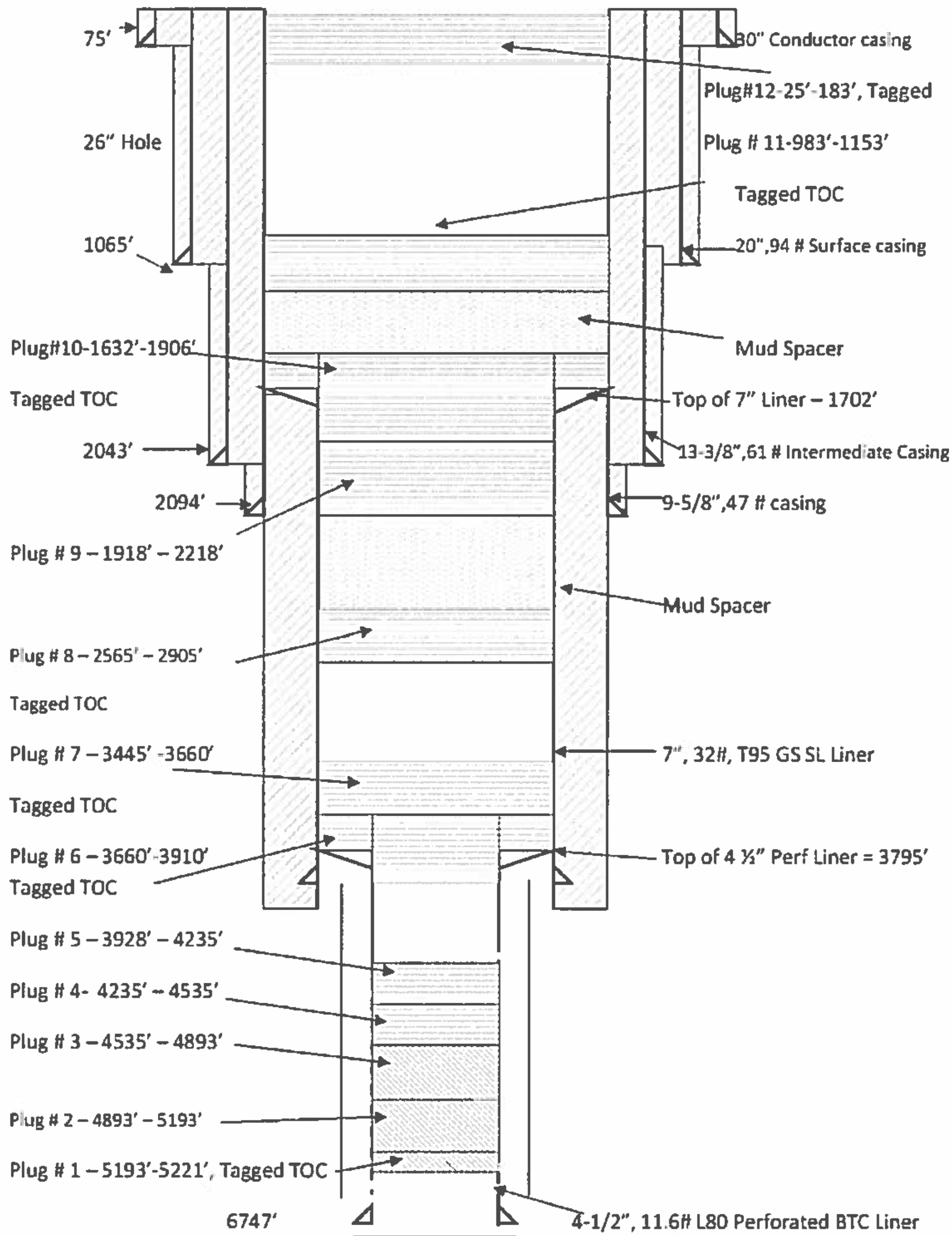
Comments: Kept well dead with water from surface. Waited for approval from DLNR to plug and abandon well. Cleaned and serviced rig and drilling tools in warehouse stock.

31-May-10 Current Depth (ft): 5,454

Comments: Kept well dead with water from surface. Waited for approval from DLNR to plug and abandon well. Cleaned and serviced rig and drilling tools in warehouse stock.

01-Jun-10	Current Depth (ft):	5,454
	Comments:	Kept well dead with water from surface. Waited for approval from DLNR to plug and abandon well. Cleaned and serviced rig and drilling tools in warehouse stock.
02-Jun-10	Current Depth (ft):	5,454
	Comments:	Kept well dead with water from surface. Waited for approval from DLNR to plug and abandon well. RIH from 3757' Tag up on bad spot at 5235', Rig and run Kuster P/T survey to 5224', 496 F @ 5224', POOH to 5160', Close and lock pipe rams, Kept well dead with water from surface. Wait for approval from DLNR to plug and abandon well.
03-Jun-10	Current Depth (ft):	5,221
	Comments:	Waiting on permits for P&A, RIH to 5380'. (Tool joints hanging up in bad spots below 5232'), POOH to 5224', Circ and monitored well while waiting on permits Received the approval for the P & A. Rigged up Halliburton cementing and set plug #1 6.0 barrels retarded 15 ppg tail cement at 5221', POOH to 3725', WOC.
04-Jun-10	Current Depth (ft):	2,905
	Comments:	WOC,RIH, tagged top of cement at 5193'. Pumped plug #2 4.5 barrels retarded 15 ppg tail cement at 5193', CIP @ 02:45 Hrs. Pulled out to 4848', Set plug #3 4.5 barrels retarded 15 ppg tail cement at 4848', CIP @ 03:10 Hrs. Pulled out to 4535', cleared pipe. Set plug # 4 4.5 barrels accelerated 15 ppg tail cement at 4535', CIP @ 04:05 Hrs. Pulled out to 4223'.Set plug #5 5.0 barrels accelerated 15 ppg tail cement at 4223', CIP @ 04:27 Hrs. Pulled out to 3910', Clear pipe, Set plug #6 8.0 barrels accelerated 15 ppg tail cement at 3910', CIP @ 05:20 Hrs. WOC, RIH tagged top of cement at 3660'. Pump plug #7 4.5 barrels accelerated 15 ppg tail cement at 3627', CIP @ 12:15 Hrs, WOC. RIH tagged top of cement at 3445'. Spot 34 Bbls Mud spacer, pulled out to 2905'. Set plug # 8 4.5 barrels accelerated 15 ppg tail cement at 2905', CIP @ 18:30 Hrs. WOC.
05-Jun-10	Current Depth (ft):	15
	Comments:	RIH tagged top of cement at 2565', Spot 15 barrel mud spacer, Pulled out to 2218', Set plug #9 4.5 barrels accelerated 15 ppg tail cement at 2218', CIP @ 03:05 Hrs, Pulled out to 1906', Set plug #10 4.5 barrels accelerated 15 ppg tail cement at 1906', CIP @ 03:25 Hrs. WOC, RIH, tagged top of cement at 1632', Spotted 35 barrel mud spacer, Pulled out to 1153', Set plug #11 4.5 barrels accelerated 15 ppg tail cement at 1153', CIP @ 11:53 Hrs. WOC, RIH tagged top of cement at 983', Displaced hole with high vis mud. Set plug #12 18 barrels accelerated tail cement from 183' to surface, CIP @ 23:30 Hrs.
06-Jun-10	Current Depth (ft):	15
	Comments:	Nippled down Bop's, Preped and lowered derrick.
07-Jun-10	Current Depth (ft):	15
	Comments:	Rig down and move rig off well. Cut off well head and welded on plate.
08-Jun-10	Current Depth (ft):	15
	Comments:	Stack rig in lay down yard, Pressure washed and cleaned equipment for shipping.

KS 4 RD2 PLUG AND ABANDONMENT WELL BORE SCHEMATIC as on 6/6/10



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Bit Record & BHA Reports

Bit Summary Report

Well ID: KS-4 RD CO 2
Field: Kilauea East Rift Zone

CONFIDENTIAL - G R G Inc
Well Name: KS-4RD Clean Out
County: Hawaii State: HI Country: United States

No	Run No	Diam	Manuf.	Model	Serial No	Nozzles - 1/32 in	TFA	Date/Time In	Depth - ft In	Depth - ft Out	Hole Made	Hrs	ROP	WOB	RPM	Flow	MWt	Grading In	Grading Out	Grading Major	Grading Loc	Grading Brg	Grading Gge	Grading Oth	Pull
Well ID: KS-4 RD CO 2						Well Name: KS-4RD Clean Out																			
1	1	6.000	HTC	MX-18	5167420	20 20 20	0.920	21-May-10 10:00	2811	2811	0		0.0				8.30	1	2	NO	A	E	0	CT	BHA
2	1	3.875	B HUGHE	HC405Z	7014501		0.000	23-May-10 16:30	3785	3892	107	11.0	9.7	1000	20	212	8.60								
2	2	3.875	B HUGHE	HC405Z	7014501	10 10 10 10 10	0.383	24-May-10 17:00	3892	5509	1617	33.0	49.0	1000	50	100	8.60	1	7	LT	G	X	2	BT	BHA
3	1	3.750	WEATH	Junk Mill	19088			27-May-10 00:10	5454	5454	0	8.5	0.0	1	25	165	8.60	0	4	RG	S	X	1	WG	OTH

BHA Report	CONFIDENTIAL - G R G Inc
Well ID: KS-4 RD CO 2	Well Name: KS-4RD Clean Out
Field: Kilauea East Rift Zone	County: Hawaii State: HI Country: United States

BHA No: 4 — **Original Well Bore**

BHA Length (ft):	3,341.52			
	Weights in Air	Buoyed Weight at Mud Wt of (lbs/gal):		8.30
BHA Wt:	20,367	17,783		
Drillstring Wt:	20,367	17,783		
Wt Above Jars:	20,045	17,502		
Wt Below Jars:	208	182		
	In	Out		
Depth (ft):	3,785	3,892		
Date/Time:	18-May-10 16:30	24-May-10 13:00		
Inclination:				
Azimuth:				
Average RPM:		Drilling Hrs.:	11	
Build Rate:		Walk Rate:		
WOB - Avg (lbs):		WOB - Max (lbs):		
Comments:	Clean out 4 1/2" liner			

BHA Component Details

Item	No. Jnts	Length	O.D.	I.D.	Weight	Grade	Top Connection	P/B	Comment
BIT	1	0.62	3.875				2.375REG	Pin	PDC mill, 5 ports S/No: 7014501
XO	1	0.42	2.875	1.000	19.4		2.375PAC	Pin	WFT S/No: 222999
MMTR	1	8.72	2.875	1.500	16.1		2.375PAC	Box	Mac temp vane S/No: 235829

Mud Motor:	Type:	Manufacturer:	WEATH	Model:	Mac
Lobe Configuration:		Speed:	5 Stages:	Torque:	480 ft lbs
Dir. Company:		Bend Setting:		Distance:	ft
Bearing Stab. OD:	ins	☐ Motor Pad	☐ Motor Failure	Failure Time:	
Comments:	Mac drill motor, high temp vane motor. Positive displacement.				

Item	No. Jnts	Length	O.D.	I.D.	Weight	Grade	Top Connection	P/B	Comment
JARS	1	5.86	2.875	1.000	19.4		2.375PAC	Box	Directional jar, wft S/No: 02880029
OTHER	1	1.33	2.875	1.063	19.0		2.375PAC	Box	Dual flapper check valve S/No: 261556
FISUB	1	6.45	2.875	1.000	19.4		2.375PAC	Box	Down hole filter S/No: 258460
XO	1	0.39	2.875	1.000	19.4		2.375REG	Box	WFT S/No: 300740
SAFETY	1	1.89	3.063	1.250	20.9		2.375REG	Box	BOT S/No: CDoo-996
XO	1	0.99	2.875	1.000	19.4		2.375EUE	Box	BOT S/No: 2873
TUBG	94	2,944.73	2.375	1.990	4.5		2.375EUE	Box	S/No: Rig
XO	1	2.05	4.750	1.990	49.7		3.5IF	Box	BOT
HWDP	12	368.07	3.500	2.370	17.7		3.5IF	Box	S/No: Rig
Total :		3,341.52							

BHA Report

CONFIDENTIAL - G R G Inc

Well ID: KS-4 RD CO 2 | Well Name: KS-4RD Clean Out

Field: Kilauea East Rift Zone | County: Hawaii State: HI Country: United States

BHA No: 5 | **Original Well Bore**

BHA Length (ft):	3,341.52			
	Weights in Air	Buoyed Weight at Mud Wt of (lbs/gal):		8.30
BHA Wt:	20,367	17,783		
Drillstring Wt:	20,367	17,783		
Wt Above Jars:	20,045	17,502		
Wt Below Jars:	208	182		
	In	Out		
Depth (ft):	3,892	5,509		
Date/Time:	24-May-10 17:00	26-May-10 21:00		
Inclination:				
Azimuth:				
Average RPM:	50	Drilling Hrs.:	33	
Build Rate:		Walk Rate:		
WOB - Avg (lbs):	1	WOB - Max (lbs):	6	
Comments:				

BHA Component Details

Item	No. Jnts	Length	O.D.	I.D.	Weight	Grade	Top Connection	P/B	Comment
BIT	1	0.62	3.875				2.375REG	Pin	PDC mill, 5 ports S/No: 7014501
XO	1	0.42	2.875	1.000	19.4		2.375PAC	Pin	WFT S/No: 222999
MMTR	1	8.72	2.875	1.500	16.1		2.375PAC	Box	Mac temp vane S/No: 235829

Mud Motor: Type: Manufacturer: WEATH Model: Mac

Lobe Configuration: Speed: 5 Stages: Torque: 480 ft lbs

Dir. Company: Bend Setting: Distance: ft

Bearing Stab. OD: ins ☐ Motor Pad ☐ Motor Failure Failure Time:

Comments: Mac drill motor, high temp vane motor. Positive displacement.

Item	No. Jnts	Length	O.D.	I.D.	Weight	Grade	Top Connection	P/B	Comment
JARS	1	5.86	2.875	1.000	19.4		2.375PAC	Box	Directional jar, wft S/No: 02880029
OTHER	1	1.33	2.875	1.063	19.0		2.375PAC	Box	Dual flapper check valve S/No: 261556
FISUB	1	6.45	2.875	1.000	19.4		2.375PAC	Box	Down hole filter S/No: 258460
XO	1	0.39	2.875	1.000	19.4		2.375REG	Box	WFT S/No: 300740
SAFETY	1	1.89	3.063	1.250	20.9		2.375REG	Box	BOT S/No: CDoo-996
XO	1	0.99	2.875	1.000	19.4		2.375EUE	Box	BOT S/No: 2873
TUBG	94	2,944.73	2.375	1.990	4.5		2.375EUE	Box	S/No: Rig
XO	1	2.05	4.750	1.990	49.7		3.5IF	Box	BOT
HWDP	12	368.07	3.500	2.370	17.7		3.5IF	Box	S/No: Rig
Total :		3,341.52							

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Operations Analysis & Summary

Operations Time Analysis

CONFIDENTIAL - G R G Inc

Well ID: KS-4 RD CO 2 | Well Name: KS-4RD Clean Out

Field: Kilauea East Rift Zone | County: Hawaii State: HI Country: United States

Geo Drill #4		Total Hrs	% of Total
DRILL			
Milling		1.00	0.2
	Total	1.00	0.2
MOB			
Mob/Demob		12.00	2.7
	Total	12.00	2.7
TRIP			
Tripping pipe		12.00	2.7
	Total	12.00	2.7
DRILL			
Circulate/Condition Mud		21.00	4.7
Reaming/Underreaming		55.00	12.4
Running Survey Tools		2.50	0.6
	Total	78.50	17.7
MOB			
Move Rig/Rig Up/Rig Down		12.00	2.7
	Total	12.00	2.7
TRIP			
Tripping Out		35.50	8.0
Tripping in		62.00	14.0
	Total	97.50	22.0
BOPOPS			
BOP Nipple Down		11.00	2.5
BOP Nipple Up		2.00	0.5
BOP Testing		1.00	0.2
	Total	14.00	3.2
CEMENT			
Cement Plug Operations		8.50	1.9
Waiting On Cement		32.00	7.2
	Total	40.50	9.1
MOB			
Rigging Down		18.00	4.1
Rigging Up		12.00	2.7
	Total	30.00	6.8
OTHER			
Other Activity		135.50	30.5
Rig Service		2.50	0.6
	Total	138.00	31.1
PROBLM			
Rig Repairs		1.00	0.2
	Total	1.00	0.2
TRIP			
BHA Operations		7.50	1.7
	Total	7.50	1.7

Geo Drill #4	Total Hrs	% of Total
Total Elapsed Time for Well	444.00	
Total Non-Productive Time for Well	68	15.3
Total Productive Time for Well	376	84.7

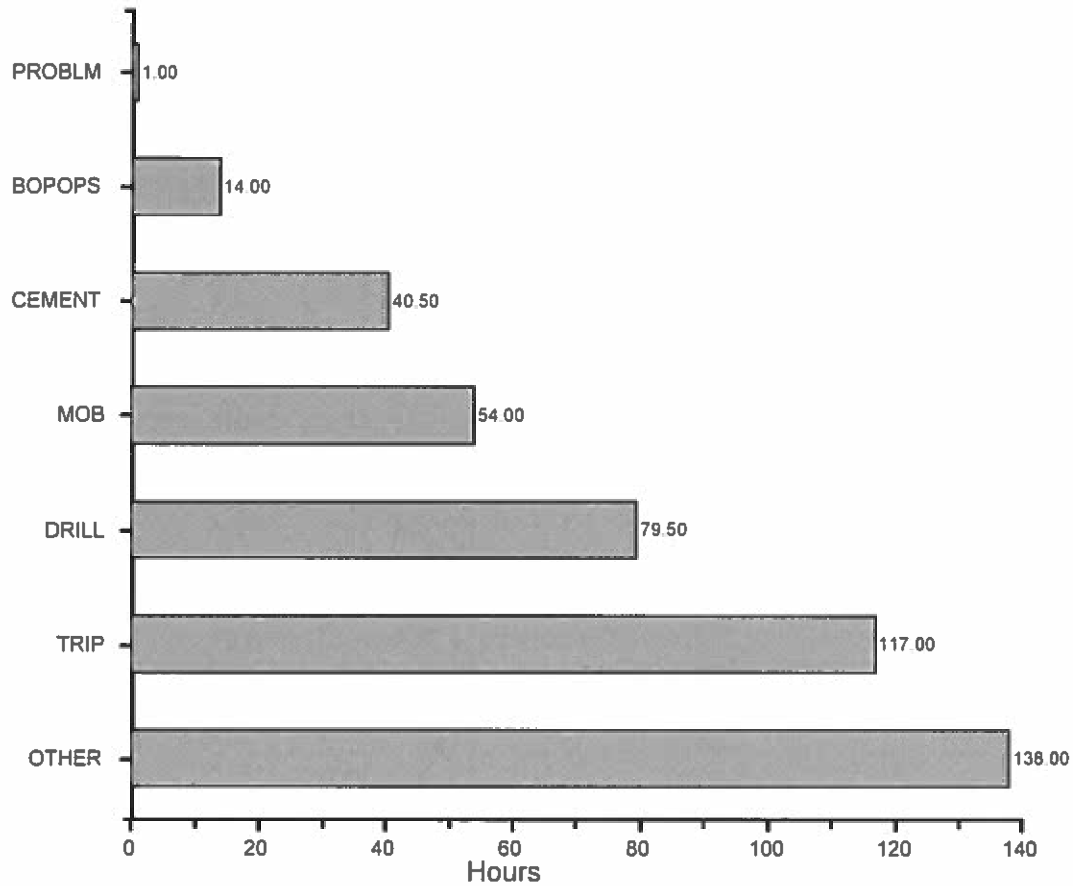
Operations Time Graph

CONFIDENTIAL - G R G Inc

Well ID: KS-4 RD CO 2 | Well Name: KS-4RD Clean Out

Field: Kilauea East Rift Zone | County: Hawaii State: HI Country: United States

Operations Analysis Type: **Analysis by Group Totals**

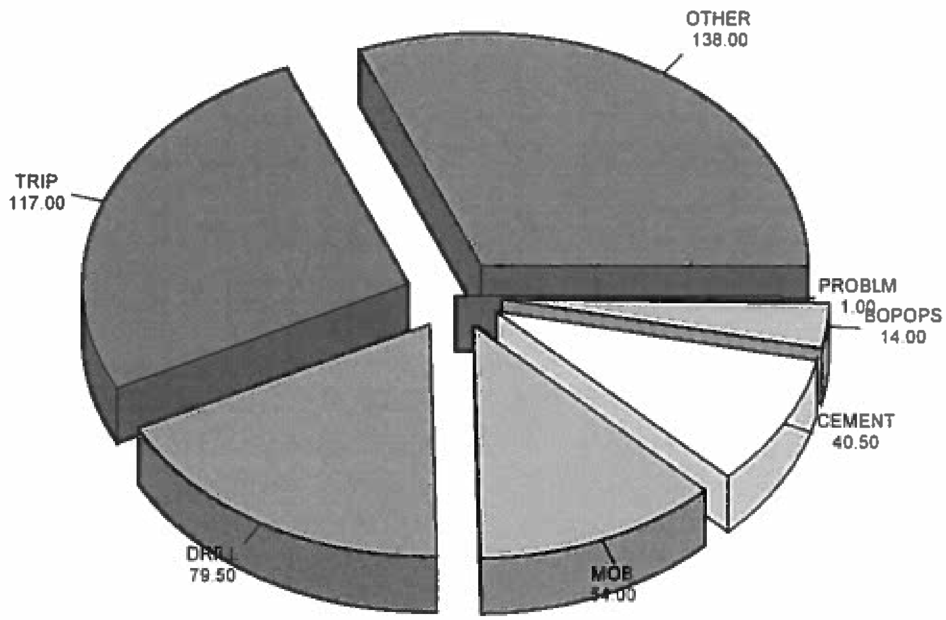


Operations Time Details

Description	Time (hrs)	%
Other Activity	138.00	31.1%
TRIP	117.00	26.4%
DRILL	79.50	17.9%
Mob/Demob	54.00	12.2%
CEMENT	40.50	9.1%
BOPOPS	14.00	3.2%
PROBLM	1.00	0.2%
Total Time:	444.00 hrs	

Operations Time Graph	CONFIDENTIAL - G R G Inc
Well ID: KS-4 RD CO 2	Well Name: KS-4RD Clean Out
Field: Kilauea East Rift Zone	County: Hawaii State: HI Country: United States

Operations Analysis Type: Analysis by Group Totals

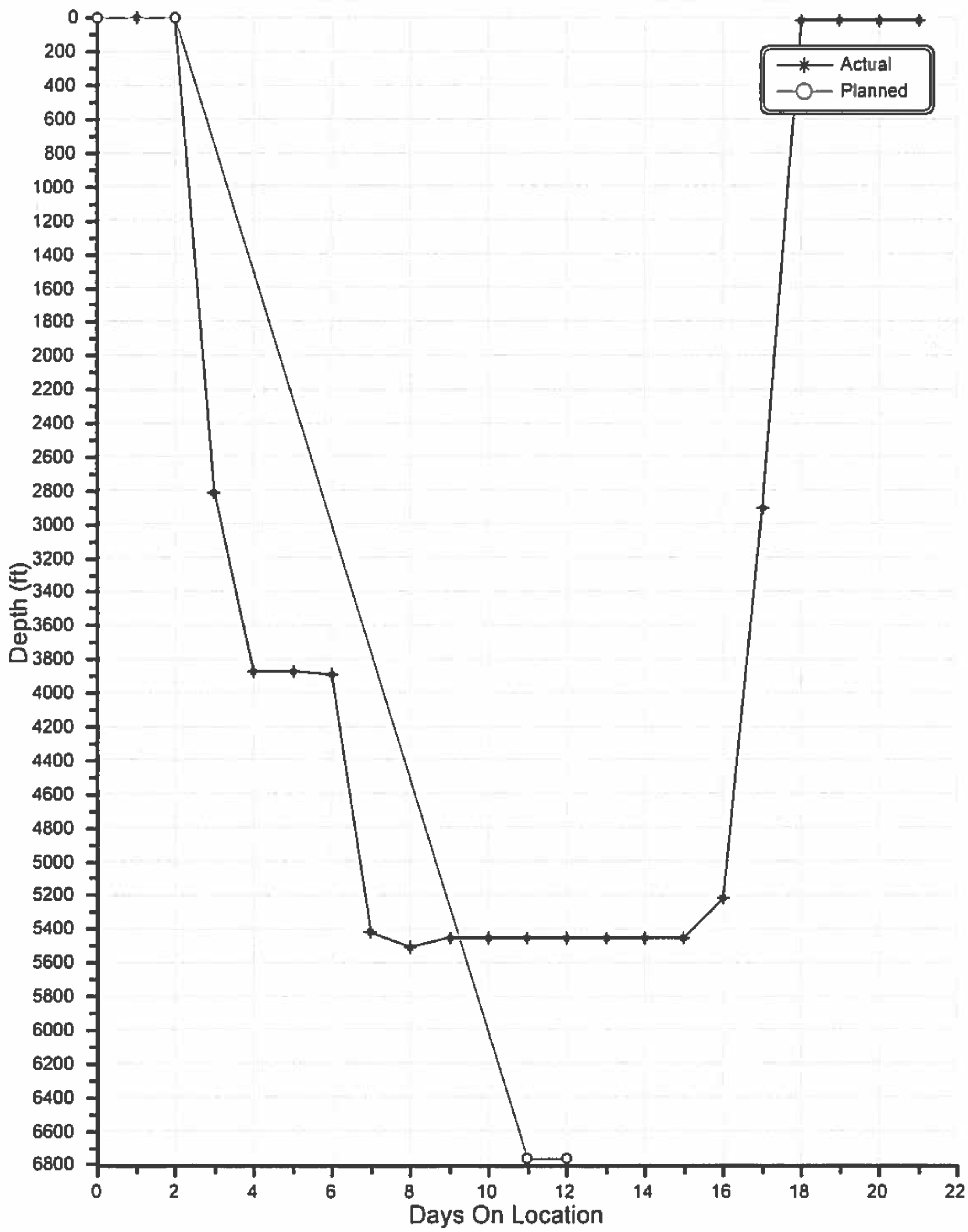


Operations Time Details

Description	Time (hrs)	%
Other Activity	138.00	31.1%
TRIP	117.00	26.4%
DRILL	79.50	17.9%
Mob/Demob	54.00	12.2%
CEMENT	40.50	9.1%
BOPOPS	14.00	3.2%
PROBLM	1.00	0.2%
Total Time:	444.00 hrs	

	Days Vs Depth	**CONFIDENTIAL - G R G Inc**
	Well ID: KS-4 RD CO 2	Well Name: KS-4RD Clean Out
	Field: Kilauea East Rift Zone	County: Hawaii State: HI Country: United States

Well Bore: All Well Bores



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Management & Cost Summary Report

Well Information Report

CONFIDENTIAL - G R G Inc

Well ID: KS-4 RD CO 2 | Well Name: KS-4RD Clean Out
Field: Kilauea East Rift Zone | County: Hawaii State: HI Country: United States

Operator:	Puna geothermal Venture	Division:	Hawaii
Classification:	Production ☐ Tight Hole	Working Interest:	
On/OffShore:	Onshore	API No:	
Latitude:	19 deg 28.518'N	Longitude:	154deg 53.4971'W
Location:	9360.90' E and 8289.03' N of the Kaliu BM, Kapoho, Puna District		
Field:	Kilauea East Rift Zone	State: HI County:	Hawaii
Orig. RKB Elev (ft):	25.60	Ground Elev (ft):	619.00
Casing Head Elev (ft):		Tubing Head Elev (ft):	
Other Datum Point:	Rig RKB	Other Datum Elev (ft):	15.60
		Spud Date:	21-May-10
		Rig Tel No:	
Date On Locn:	19-May-10		
Engineer(s):	Rickard, Spielman		

Well Bore: Original Well Bore

Proposed TD (ft): 6,767 ID No: 0

Hole Section Information

Section Plan: MOVE

Time/Cost Estimates:		Size Hole:	4.500	Btm Depth MD:	0	TVD:	
Drill Days:		Drill Cost:		Case/Eval Days:	2	Case/Eval Cost:	
Casing Plan:	Type:	O.D:		Top MD:		Top TVD:	
Weight:	Grade:	Thread:		Btm MD:		Btm TVD:	
Notes:							

Section Plan: PROD

Time/Cost Estimates:		Size Hole:	7.000	Btm Depth MD:	6,767	TVD:	
Drill Days:	9	Drill Cost:		Case/Eval Days:	1	Case/Eval Cost:	
Casing Plan:	Type:	O.D:		Top MD:		Top TVD:	
Weight:	Grade:	Thread:		Btm MD:		Btm TVD:	
Notes:							

Actual Data:	TD Date	MD (ft)	TVD (ft)	Status
		6,767		PRODGEO

AFE Information

AFE No.	Description	Amount $
KS-4 RD CO 2		

Actual Costs vs AFE Costs Report — CONFIDENTIAL - G R G Inc

Well ID: KS-4 RD CO 2 | Well Name: KS-4RD Clean Out

Field: Kilauea East Rift Zone | County: Hawaii State: HI Country: United States

AFE Number: KS-4 RD CO 2

Code	Account Description	AFE	Well Total	Difference	%Spent
10250	Drill String/Bits		41,381	(41,381)	N/A
10601	Mud		8,544	(8,544)	N/A
10853	Rig Maintenance - Rentals		10,638	(10,638)	N/A
	Total for AFE Number: KS-4 RD CO 2 $		60,563	(60,563)	N/A

AFE Number: None

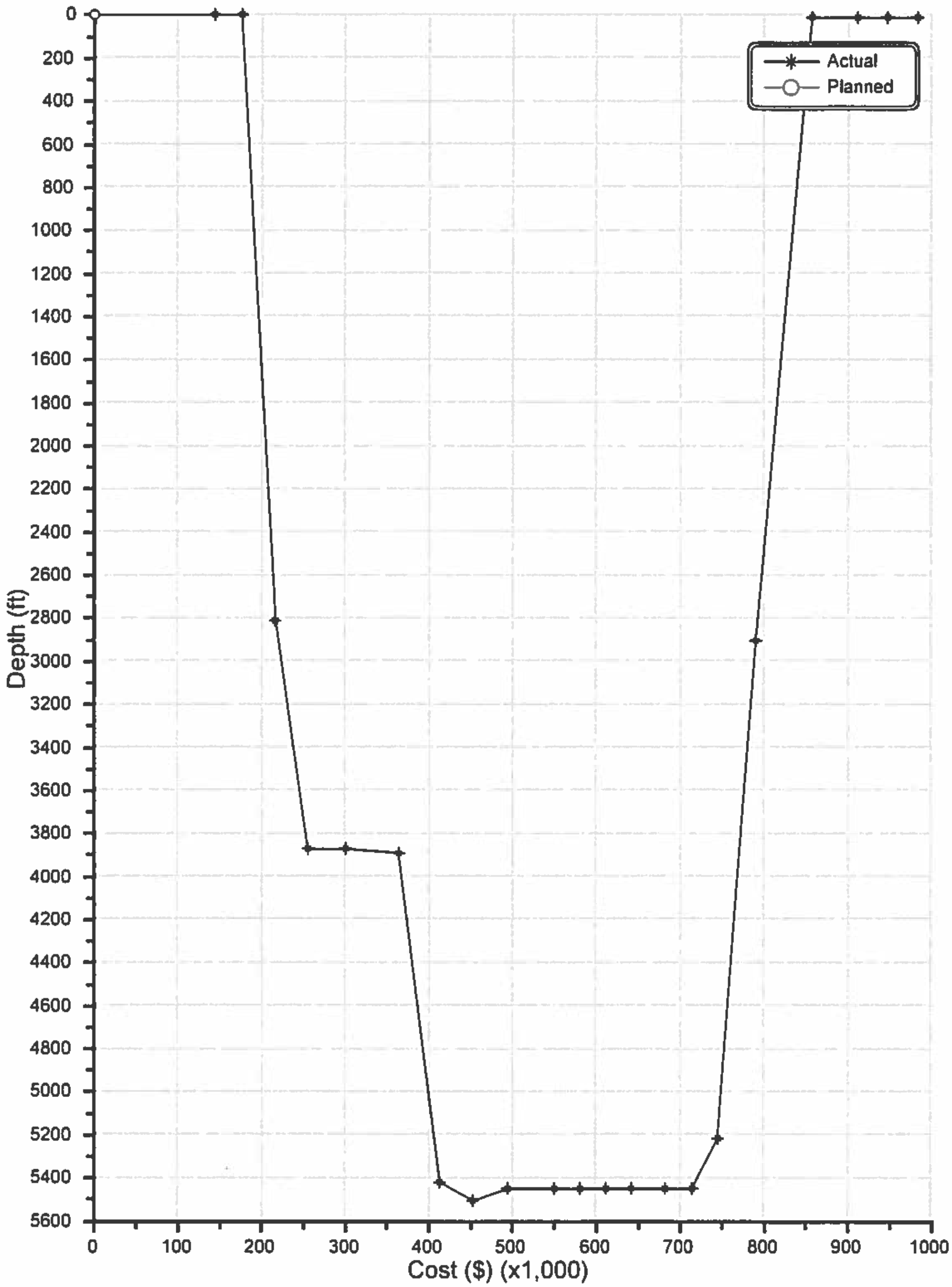
Code	Account Description	AFE	Well Total	Difference	%Spent
10106	Engineering & Studies		14,700	(14,700)	N/A
10121	Office Equipment		4,200	(4,200)	N/A
10143	Sanitation & Disposal		1,260	(1,260)	N/A
10250	Drill String/Bits		178,711	(178,711)	N/A
10350	BOPE		18,090	(18,090)	N/A
10420	Trucking		5,435	(5,435)	N/A
10521	Daywork Operating		281,226	(281,226)	N/A
10601	Mud		37,018	(37,018)	N/A
10641	Mud Logging		67,200	(67,200)	N/A
10660	Cementing		72,243	(72,243)	N/A
10660	Cement jobs		58,585	(58,585)	N/A
10840	Supervision		94,500	(94,500)	N/A
10841	Labor		56,112	(56,112)	N/A
10851	Rig Maintenance - Service		687	(687)	N/A
10852	Rig Maintenance - Supplies		561	(561)	N/A
10880	Misc. daily		3,640	(3,640)	N/A
10880.	Misc.		21,012	(21,012)	N/A
10884	Rentals		7,287	(7,287)	N/A
	Total for AFE Number: None $		922,467	(922,467)	N/A
	Total All Costs $	0	983,030	(983,030)	N/A

Cost Vs Depth

CONFIDENTIAL - G R G Inc

Well ID: KS-4 RD CO 2 | Well Name: KS-4RD Clean Out

Field: Kilauea East Rift Zone | County: Hawaii State: HI Country: United States



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Cement and Casing

Cementing Report

CONFIDENTIAL - G R G Inc

Well ID: KS-4 RD CO 2 | Well Name: KS-4RD Clean Out

Field: Kilauea East Rift Zone | County: Hawaii State: HI Country: United States

CEMENT JOB INFORMATION

Start Date/Time:	04-Jun-10 02:30	Well Bore:	Original Well Bore
Job Type:	PLUG	Cementing Engineer:	Juan Lozano
Cementing Co:	HALLBTN		

PLUG JOB DETAIL

Plug Type:	Abandament				
Plug: Top (ft):	4,893	Bottom (ft):	5,193	Length (ft):	300
Calc. Displacement Vol (bbls):	25.000	Hole Size at Plug (ins):	3.875		

	Volume (bbls)	Pump Time	Rate (bbls/min)	Volume (psi)
Conditioning Data:		2	4.5	1,330
Cement Data:	4.5	1	4.5	1,280
Displacement Data:	24.6	6	4.5	1,180

SLURRY INFORMATION

Type	Density	Yield	Sacks	Volume	Rate	Additives
FLUSH	8.30			10.0	4.5	Water
TAIL	15.00	1.77	16	4.5	4.5	Hawaiian type 1-11 Cement with 35% SSA-1,+ 5% Microlite,+ .65% Halad-322,+.5% USC,+ .10%GPS SCR100
DISPLACE	8.30			24.6	4.5	Water.

POSTJOB INFORMATION

Actual Top of Cmt (ft):		Job Success?	Yes
Misc. Comments:	Plug # 2, CIP @ 02:45 Hrs.		

Cementing Report

CONFIDENTIAL - G R G Inc

Well ID: KS-4 RD CO 2 | Well Name: KS-4RD Clean Out

Field: Kilauea East Rift Zone | County: Hawaii State: HI Country: United States

CEMENT JOB INFORMATION

Start Date/Time:	04-Jun-10 03:00	Well Bore:	Original Well Bore
Job Type:	PLUG	Cementing Engineer:	Juan Lozano
Cementing Co:	HALLBTN		

PLUG JOB DETAIL

Plug Type:	Abandament				
Plug: Top (ft):	4,535	Bottom (ft):	4,848	Length (ft):	313
Calc. Displacement Vol (bbls):	24.000	Hole Size at Plug (ins):	3.875		

	Volume (bbls)	Pump Time	Rate (bbls/min)	Volume (psi)
Conditioning Data:		2	4.5	1,300
Cement Data:	4.5	1	4.5	1,330
Displacement Data:	24.0	5	4.5	1,250

SLURRY INFORMATION

Type	Density	Yield	Sacks	Volume	Rate	Additives
FLUSH	8.30			10.0	4.5	Water
TAIL	15.00	1.77	16	4.5	4.5	Hawaiian type 1-11 Cement with 35% SSA-1,+ 5% Microlite,+ .65% Halad-322,+.5% USC,+ .10%GPS SCR100
DISPLACE	8.30			24.0	4.5	Water

POSTJOB INFORMATION

Actual Top of Cmt (ft):		Job Success?	Yes
Misc. Comments:	Plug # 3, CIP @ 03:10 Hrs.		

Cementing Report

CONFIDENTIAL - G R G Inc

Well ID: KS-4 RD CO 2 **Well Name:** KS-4RD Clean Out

Field: Kilauea East Rift Zone **County:** Hawaii **State:** HI **Country:** United States

CEMENT JOB INFORMATION

Start Date/Time:	03-Jun-10 17:30	Well Bore:	Original Well Bore
Job Type:	PLUG	Cementing Engineer:	Juan Lozano
Cementing Co:	HALLBTN		

PLUG JOB DETAIL

Plug Type:	Abandonment				
Plug: Top (ft):	4,821	Bottom (ft):	5,221	Length (ft):	400
Calc. Displacement Vol (bbls):	25.630	Hole Size at Plug (ins):	3.875		

	Volume (bbls)	Pump Time	Rate (bbls/min)	Volume (psi)
Conditioning Data:		3	4.5	1,740
Cement Data:	6.0	2	4.5	1,648
Displacement Data:	25.0	5	4.5	1,480

SLURRY INFORMATION

Type	Density	Yield	Sacks	Volume	Rate	Additives
FLUSH	8.30			10.0	4.5	Water.
TAIL	15.00	1.77	19	6.0	4.5	Hawaiian type 1-11 Cement with 35% SSA-1,+ 5% Microlite,+ .65% Halad-322,+.5% USC,+ .10%GPS SCR100
DISPLACE	8.30			25.0	4.5	Water.

POSTJOB INFORMATION

Actual Top of Cmt (ft):	5,193	Job Success?	Yes
Misc. Comments:	Plug # 1, CIP @ 18:00 Hrs.		

Cementing Report

CONFIDENTIAL - G R G Inc

Well ID: KS-4 RD CO 2 | Well Name: KS-4RD Clean Out
Field: Kilauea East Rift Zone | County: Hawaii State: HI Country: United States

CEMENT JOB INFORMATION

Start Date/Time:	04-Jun-10 03:55	Well Bore:	Original Well Bore
Job Type:	PLUG	Cementing Engineer:	Juan Lozano
Cementing Co:	HALLIBTN		

PLUG JOB DETAIL

Plug Type:	Abandament				
Plug: Top (ft):	4,235	Bottom (ft):	4,535	Length (ft):	300
Calc. Displacement Vol (bbls):	21.000	Hole Size at Plug (ins):	3.875		

	Volume (bbls)	Pump Time	Rate (bbls/min)	Volume (psi)
Conditioning Data:		2	4.5	1,470
Cement Data:	4.5	1	4.5	1,440
Displacement Data:	21.0	4	4.5	1,280

SLURRY INFORMATION

Type	Density	Yield	Sacks	Volume	Rate	Additives
FLUSH	8.30			10.0	4.5	Water
TAIL	15.00	1.77	16	4.5	4.5	Hawaiian type 1-11 Cement with 35% SSA-1,+ 5% Microlite,+ .65% Halad-322,+.5% USC, 1% CaCl2
DISPLACE	8.30			21.0	4.5	Water

POSTJOB INFORMATION

Actual Top of Cmt (ft):		Job Success?	Yes
Misc. Comments:	Plug # 4, CIP @ 04:05 Hrs.		

Cementing Report — CONFIDENTIAL - G R G Inc

Well ID: KS-4 RD CO 2 — Well Name: KS-4RD Clean Out

Field: Kilauea East Rift Zone — County: Hawaii State: HI Country: United States

CEMENT JOB INFORMATION

Start Date/Time:	04-Jun-10 04:15	Well Bore:	Original Well Bore
Job Type:	PLUG	Cementing Engineer:	Juan Lozano
Cementing Co:	HALLBTN		

PLUG JOB DETAIL

Plug Type:	Abandament				
Plug: Top (ft):	3,923	Bottom (ft):	4,223	Length (ft):	300
Calc. Displacement Vol (bbls):	19.000	Hole Size at Plug (ins):	3.875		

	Volume (bbls)	Pump Time	Rate (bbls/min)	Volume (psi)
Conditioning Data:		2.5	4.5	1,240
Cement Data:	5.0	1	4.5	1,256
Displacement Data:	19.0	4	4.5	1,280

SLURRY INFORMATION

Type	Density	Yield	Sacks	Volume	Rate	Additives
FLUSH				10.0	4.5	Water
TAIL	15.00	1.77	16	5.0	4.5	Hawaiian type 1-11 Cement with 35% SSA-1,+ 5% Microlite,+ .65% Halad-322,+.5% USC, 1% CaCl2
DISPLACE				19.0	4.5	Water

POSTJOB INFORMATION

Actual Top of Cmt (ft):		Job Success?	Yes
Misc. Comments:	Plug # 5, CIP @ 04:27 Hrs		

Cementing Report	**CONFIDENTIAL - G R G Inc**
Well ID: KS-4 RD CO 2	Well Name: KS-4RD Clean Out
Field: Kilauea East Rift Zone	County: Hawaii State: HI Country: United States

CEMENT JOB INFORMATION

Start Date/Time:	04-Jun-10 05:15	Well Bore:	Original Well Bore
Job Type:	PLUG	Cementing Engineer:	Jaun Lozano
Cementing Co:	HALLBTN		

PLUG JOB DETAIL

Plug Type:	Abandament				
Plug: Top (ft):	3,610	Bottom (ft):	3,910	Length (ft):	300
Calc. Displacement Vol (bbls):	17.000	Hole Size at Plug (ins):	3.875		

	Volume (bbls)	Pump Time	Rate (bbls/min)	Volume (psi)
Conditioning Data:		2	4.5	1,240
Cement Data:	8.0	2	4.5	1,250
Displacement Data:	17.0	3	4.5	990

SLURRY INFORMATION

Type	Density	Yield	Sacks	Volume	Rate	Additives
FLUSH	8.30			10.0	4.5	Water
TAIL	15.00	1.77	25	8.0	4.5	Hawaiian type 1-11 Cement with 35% SSA-1,+ 5% Microlite,+ .65% Halad-322,+.5% USC, 1% CaCl2
DISPLACE	8.30			17.0	4.5	Water

POSTJOB INFORMATION

Actual Top of Cmt (ft):	3,660	Job Success?	Yes
Misc. Comments:	Plug # 6, CIP @ 05:20 Hrs		

Cementing Report | **CONFIDENTIAL - G R G Inc**

Well ID: KS-4 RD CO 2 | Well Name: KS-4RD Clean Out

Field: Kilauea East Rift Zone | County: Hawaii State: HI Country: United States

CEMENT JOB INFORMATION

Start Date/Time:	04-Jun-10 12:00	Well Bore:	Original Well Bore
Job Type:	PLUG	Cementing Engineer:	Juan Lozano
Cementing Co:	HALLBTN		

PLUG JOB DETAIL

Plug Type:	Abandament				
Plug: Top (ft):		Bottom (ft):	3,627	Length (ft):	3,627
Calc. Displacement Vol (bbls):	16.000	Hole Size at Plug (ins):	6.094		

	Volume (bbls)	Pump Time	Rate (bbls/min)	Volume (psi)
Conditioning Data:		2	4.5	990
Cement Data:	11.0	3	4.5	845
Displacement Data:	16.0	4	4.5	570

SLURRY INFORMATION

Type	Density	Yield	Sacks	Volume	Rate	Additives
FLUSH	8.30			10.0	4.5	Water
TAIL	15.00	1.77	35	11.0	4.5	Hawaiian type 1-11 Cement with 35% SSA-1,+ 5% Microlite,+ .65% Halad-322,+.5% USC, 1% CaCl2
DISPLACE	8.30	1.77		16.0	4.5	Water.

POSTJOB INFORMATION

Actual Top of Cmt (ft):	3,445	Job Success?	Yes
Misc. Comments:	Plug # 7, CIP @ 12:15 Hrs.		

Cementing Report

CONFIDENTIAL - G R G Inc

Well ID: KS-4 RD CO 2 | Well Name: KS-4RD Clean Out

Field: Kilauea East Rift Zone | County: Hawaii State: HI Country: United States

CEMENT JOB INFORMATION

Start Date/Time:	05-Jun-10 02:55	Well Bore:	Original Well Bore
Job Type:	PLUG	Cementing Engineer:	Juan Lozano
Cementing Co:	HALLBTN		

PLUG JOB DETAIL

Plug Type:	Abandament				
Plug: Top (ft):	1,918	Bottom (ft):	2,218	Length (ft):	300
Calc. Displacement Vol (bbls):	13.000	Hole Size at Plug (ins):	6.366		

	Volume (bbls)	Pump Time	Rate (bbls/min)	Volume (psi)
Conditioning Data:		2	4.5	435
Cement Data:	11.0	2.5	4.5	230
Displacement Data:	13.0	3	4.5	420

SLURRY INFORMATION

Type	Density	Yield	Sacks	Volume	Rate	Additives
FLUSH	8.30			10.0	4.5	Water.
TAIL	15.00	1.77		11.0	4.5	Hawaiian type 1-11 Cement with 35% SSA-1,+ 5% Microlite,+ .65% Halad-322,+.5% USC, 2% CaCl2
DISPLACE	8.30			13.0	4.5	Water.

POSTJOB INFORMATION

Actual Top of Cmt (ft):		Job Success?	Yes
Misc. Comments:	Plug # 9, CIP @ 03.05 Hrs.		

Cementing Report

CONFIDENTIAL - G R G Inc

Well ID: KS-4 RD CO 2 | Well Name: KS-4RD Clean Out

Field: Kilauea East Rift Zone | County: Hawaii State: HI Country: United States

CEMENT JOB INFORMATION

Start Date/Time:	04-Jun-10 18:15	Well Bore:	Original Well Bore
Job Type:	PLUG	Cementing Engineer:	Juan Lozano
Cementing Co:	HALLBTN		

PLUG JOB DETAIL

Plug Type:	Abandament				
Plug: Top (ft):	2,605	Bottom (ft):	2,905	Length (ft):	300
Calc. Displacement Vol (bbls):	16.000	Hole Size at Plug (ins):	6.094		

	Volume (bbls)	Pump Time	Rate (bbls/min)	Volume (psi)
Conditioning Data:		2	4.5	360
Cement Data:	11.0	2.5	4.5	350
Displacement Data:	16.0	4	4.5	366

SLURRY INFORMATION

Type	Density	Yield	Sacks	Volume	Rate	Additives
FLUSH	8.30			10.0	4.5	Water
TAIL	15.00	1.77		11.0	4.5	Hawaiian type 1-11 Cement with 35% SSA-1,+ 5% Microlite,+ .65% Halad-322,+.5% USC, 2% CaCl2
DISPLACE	8.30			16.0	4.5	Water

POSTJOB INFORMATION

Actual Top of Cmt (ft):	2,565	Job Success?	Yes
Misc. Comments:	Plug # 8, CIP @ 18:30 Hrs.		

Cementing Report

CONFIDENTIAL - G R G Inc

Well ID: KS-4 RD CO 2 — **Well Name: KS-4RD Clean Out**

Field: Kilauea East Rift Zone — **County: Hawaii State: HI Country: United States**

CEMENT JOB INFORMATION

Start Date/Time:	05-Jun-10 03:15	Well Bore:	Original Well Bore
Job Type:	PLUG	Cementing Engineer:	Juan Lozano
Cementing Co:	HALLBTN		

PLUG JOB DETAIL

Plug Type:	Abandament				
Plug: Top (ft):	1,606	Bottom (ft):	1,906	Length (ft):	300
Calc. Displacement Vol (bbls):	12.000	Hole Size at Plug (ins):	6 366		

	Volume (bbls)	Pump Time	Rate (bbls/min)	Volume (psi)
Conditioning Data:		2	4 5	433
Cement Data:	15.0	4	4.5	132
Displacement Data:	12.0	3	4 5	249

SLURRY INFORMATION

Type	Density	Yield	Sacks	Volume	Rate	Additives
FLUSH	8 30			10 0	4.5	Water
TAIL	15 00	1.77		15 0	4.5	Hawaiian type 1-11 Cement with 35% SSA-1,+ 5% Microlite,+ .65% Halad-322,+.5% USC, 2% CaCl2
DISPLACE	8 30			12 0	4 5	Water

POSTJOB INFORMATION

Actual Top of Cmt (ft):	1,632	Job Success?	Yes
Misc. Comments:	Plug # 10, CIP @ 03 25 Hrs.		

Cementing Report

CONFIDENTIAL - G R G Inc

Well ID: KS-4 RD CO 2 | **Well Name: KS-4RD Clean Out**

Field: Kilauea East Rift Zone | **County: Hawaii State: HI Country: United States**

CEMENT JOB INFORMATION

Start Date/Time:	05-Jun-10 23:10	Well Bore:	Original Well Bore
Job Type:	PLUG	Cementing Engineer:	Juan Lozano
Cementing Co:	HALLBTN		

PLUG JOB DETAIL

Plug Type:	Abandament				
Plug: Top (ft):	25	Bottom (ft):	186	Length (ft):	161
Calc. Displacement Vol (bbls):	2.000	Hole Size at Plug (ins):	8.687		

	Volume (bbls)	Pump Time	Rate (bbls/min)	Volume (psi)
Conditioning Data:		2	2.0	90
Cement Data:	18 0	10	2.0	60
Displacement Data:	0.0	0	0.0	0

SLURRY INFORMATION

Type	Density	Yield	Sacks	Volume	Rate	Additives
FLUSH	8 30			2.0	2.0	water
TAIL	15 00	1.77		18.0	2.0	Hawaiian type 1-11 Cement with 35% SSA-1,+ 5% Microlite,+ .65% Halad-322,+.5% USC, 3% CaCl2
DISPLACE	8 30			0.0	0.0	

POSTJOB INFORMATION

Actual Top of Cmt (ft):	25	Job Success?	Yes
Misc. Comments:	Cement plug #12 CIP@ 23:21, back to bottom of cellar		

Cementing Report

CONFIDENTIAL - G R G Inc

Well ID: KS-4 RD CO 2

Well Name: KS-4RD Clean Out

Field: Kilauea East Rift Zone

County: Hawaii State: HI Country: United States

CEMENT JOB INFORMATION

Start Date/Time:	05-Jun-10 11:07	Well Bore:	Original Well Bore
Job Type:	PLUG	Cementing Engineer:	Juan Lozano
Cementing Co:	HALLBTN		

PLUG JOB DETAIL

Plug Type:	Abandament				
Plug: Top (ft):	953	Bottom (ft):	1,153	Length (ft):	200
Calc. Displacement Vol (bbls):	10.000	Hole Size at Plug (ins):	8.687		

	Volume (bbls)	Pump Time	Rate (bbls/min)	Volume (psi)
Conditioning Data:		1	4.5	140
Cement Data:	15.0	3	4.5	120
Displacement Data:	7.5	1	4.5	0

SLURRY INFORMATION

Type	Density	Yield	Sacks	Volume	Rate	Additives
FLUSH	8.30			10.0		water
TAIL	15.00	1.77		15.0	4.5	Hawaiian type 1-11 Cement with 35% SSA-1,+ 5% Microlite,+ .65% Halad-322,+.5% USC, 3% CaCl2
DISPLACE	830.00			7.5	4.5	water

POSTJOB INFORMATION

Actual Top of Cmt (ft):	983	Job Success?	Yes
Misc. Comments:	Cement plug # 11, CIP@11:13 Hrs		

ATTACHMENT D
UNDERGROUND SOURCE OF DRINKING WATER

The PGV Project area is located in the Lower East Rift Zone (LERZ) on the eastern flank of Kilauea Volcano. The LERZ is a conduit for lateral migration of basaltic magma flowing east-northeast from the caldera at the summit. The magma in this subsurface conduit provides the heat source for the high temperature Puna geothermal reservoir, which naturally affects the groundwater resources in the area. Underground injection at the PGV Project will essentially be a reinjection of the geothermal fluids which are withdrawn from the geothermal reservoir and used in the production of electricity. The geothermal fluids will be injected back into the geothermal reservoir at depths of approximately 4000+ feet, which is beneath an impermeable caprock which separates the geothermal reservoir from an upper groundwater zone. As a result of the 2018 Eruption in the LERZ, water wells MW-1, MW-2 and MW-3 were covered by the lava flows. In June 2019 a new well MW-4 was completed to a depth of 850 ft. and currently provides 1200 gpm of non-potable water for operation and drilling activities at PGV. A detailed report on MW-4 water chemistry and additional background geology/hydrology at PGV is provided in the attached "Semi-Annual Hydrologic Monitoring Program Report" by Cardno (August 2019). Maps and cross sections characterizing the features of the geology/hydrology under the PGV project are provided in Attachment F.

The vertical depth of the groundwater extends from the top of the impermeable caprock to the water table, approximately 580 to 700 feet below the surface near the elevation of mean sea level. As generally seen on Hawaiian oceanic islands, the groundwater exists as a lense-shaped body of fresh, meteoric-derived water, known as basal water, floating on denser saline ocean-derived groundwater. This hydrologic condition is described at the Ghyben-Heraberg principle (Fetter 1980). The near surface hydrology in the East Rift Zone is characterized by high recharge rates and rapid subsurface flow (Thomas 1987). The highly permeable subaerial basalt flows, composed of thin, highly fractured and often rubblized basalt flows, allow nearly 100% of the rainfall to infiltrate down to the basal aquifers. Groundwater transmissivities were measured by 5 X 10^4 darcies and groundwater residence times are only 10 to 20 years (Thomas 1987; Iovenitti 1990). Recharge from rainfall exceeds 120 inches per year in the LERZ and penetration of the meteoric water is essentially complete as evidenced by the absence of stream run-off and standing bodies of water.

Within the LERZ, the groundwater distribution is modified by the occurrence of near-vertical to steeply dipping dikes which act as localized semipermeable dams to groundwater flow. These physical barriers create a sub-parallel series of permeable compartments that allow the dike-controlled and dike-confined groundwater aquifers to rise significantly higher than mean sea level. Because these compartments are isolated from one another by semipermeable dikes, disparate water levels may be observed between compartments and associated water chemistries may display extreme ranges of compositions (Fetter 1980; Thomas 1987; Iovenitti 1990).

Hydrology studies by Druecker and Fan (1976) demonstrated that the dike swarms in the LERZ impacted the regional flow of groundwater. A dike is a vertical body intruding into the older lava flow; swarms refer to a number of these dikes emanating from one magma chamber. Meteoric groundwater originating north of the rift flows southerly along topographic gradients, until it is impeded by the dikes which divert the groundwater flow northeast toward the ocean. Transverse flow across the rift, therefore, is limited. Within the rift zone, groundwater flow is controlled by the en echelon dike swarms. Here, water moves down-rift parallel to the dikes toward the ocean to the northeast. Groundwater encountered south of the rift flows southerly to the ocean conforming to the local topography. Since the volume of fresh water south of the rift is relatively low, coastal waters have saline chemistries due to salt water mixing and, to a lesser degree, natural contamination by geothermal waters.

The depth to groundwater and the flow characteristics of the four monitoring wells drilled on the PGV leased property demonstrate the hydrologic characteristics described above. Historically, each monitoring well encountered the water table at different depths. The location of these monitoring wells is described in Attachment P-3, (Figure P3-1) and Attachments B & F. In MW-1, water was initially encountered at a depth of 8 feet above sea level, MW-2 encountered water at a depth of 16 feet above sea level and MW-3, drilled only 250 feet northwest of MW-1, encountered water at a depth of 14 feet above sea level. The pump test of MW-3 showed no evidence of a gradual draw down with time and both MW-3 and MW-1 displayed almost instantaneous recoveries at the conclusion of their respective pump and flow tests. These parameters are indicative of aquifers with extremely high transmissivities. MW-4 commissioned in June 2019 is located on Pad B (near KS-15) has a ground elevation of 718 ft. msl encountered the water table about 10 ft. above sea level. A pump test of MW-4 indicated a drawdown of about 14 ft.

Chemical analyses of waters from MW-1 and MW-2 exhibit disparate characters (see Table D-1). MW-2, located at the southern boundary of the known geothermal field, has a chemistry high in sodium and chloride and low in sulfate and silica. Naturally occurring total dissolved solids (TDS) typically range from 950 to 1150 mg/l. MW-1, located on the northern portion of the lease, has a chemistry high in silica and sulfate but very low in sodium and chloride. TDS concentrations in MW-1 typically range from 450 to 550 mg/l. Temperatures also differ. MW-2 displays bottom hole temperatures that fluctuate about 10ºF per day, from the high 120sºF to the high 130sºF. These fluctuations are cyclical with a 24-hour period, indicating that they are caused by tidal effects. MW-1, however, shows no diurnal temperature fluctuations as fluid temperature measurements are steady at approximately 106ºF. Fluid temperature at MW-4 measures about 128ºF at surface. Chemical analysis of MW-4 fluid indicate decreased water pH levels, increased sulfate and alkalinity (resulting from increases in H_2S and carbon dioxide (CO_2) from geothermal steam and increased concentrations of dissolved silica, chloride, and major cations (sodium, potassium, and calcium.), see Table D-1.

Water samples from wells and springs throughout the LERZ exhibit similar extreme ranges in temperature and chemistries (Cox and Thomas 1979; Thomas 1987, Iovenitti 1990). The observed variations in chemistry and temperatures are indicative of the mixing of groundwaters and geothermal waters within the rift zone. The mixing may be from four sources: cold meteoric, cold sea water, hydrothermally altered meteoric water and hydrothermally modified sea water. The observed characteristics of MW-1 and MW-2 are typical of geothermally modified groundwaters (Thomas 1987). When compared to the waters from the GTW-III or Malama Ki wells, which have higher fluid temperatures and very high concentrations of sodium, chloride, and silica, it is evident that the degree of natural mixing with geothermal sources in MW-1 and MW-2 is relatively modest.

MW-2 possesses a greater natural geothermal component than MW-1, as evidenced by higher sodium, chloride, and silica levels. These levels are similar to the waters from the GTW-III and Malama Ki monitoring wells, which are clearly affected by upwelling geothermal fluids. As evidenced by the observed temperature fluctuations, MW-2 is in communication with the groundwater south of the rift zone which is in equilibrium with the ocean. These observations indicate that the natural upwelling geothermal fluids are mixing with meteoric waters in the near surface unconfirmed aquifer beneath MW-2. The mixed fluid (groundwater) then flows southerly toward the sea. Similar interpretations were suggested by Iovenitti (1990) and Thomas (1987).

MW-1, located north of Puu Honuaula, but more significantly, north of the Rift Zone, exhibits temperature and chemical characteristics indicating that the well is isolated from the deeper geothermal reservoir. The higher than normative silica and sulfate concentrations and the elevated fluid temperatures are indicative that the groundwater is modified by geothermal mixing, but not by the leakage of the highly saline fluid typical of the producing reservoir. The absence of diurnal temperature fluctuations infers that the well is not in communication with the sea. It can be concluded from this evidence that the groundwater in MW-1 (and MW-3) probably represents meteoric water sweeping down-rift, parallel to the PGV geothermal reservoir but isolated from it by intervening dikes.

MW-4 is composed of warm saline water heated by geothermal steam from below. The geothermal steam contains elevated levels of H_2S, contributing to high sulfate levels in MW-4.

REFERENCES:

Cox, M. and Thomas D., 1979, Cl/Mg ratio of Hawaiian ground water as a regional geothermal indicator in Hawaii, Hawaii Institute of Geophysics Technical Report, HIG-79-9, 51 p.

Druecker, M., and Fan, P., 1976, Hydrology and chemistry of ground water in Puna, Hawaii, Groundwater, V. 14, No. 5, pp. 328-338.

Fetter, C., 1980, Applied Hydrogeology, Merrill Publishing Co., Columbus, Ohio, pp. 299-301, 155-153.

Iovenitti, J., 1990, Shallow Ground Water Mapping in the Lower East Rift Zone Kilauea Volcano, Hawaii, Geothermal Resources Council Transactions, V. 14, Part 1, pp. 699-703.

Thomas, D., 1987, A Geochemical Model of the Kilauea East Rift Zone, in Volcanism in Hawaii, USGS Professional Paper 1350, pp. 1507-1525.

Table D-1
QUALITY OF SHALLOW GROUNDWATER

	Pahoa (1991)	Kapoho (1991)	MW-1 (1991)	MW-2 (1991)	GTW-III (1991)	Malama Ki (1991)	MW-4 (2019)
Sodium	18.0	86.0	41.2	320.0	2430.0	2420.0	1170
Potassium	*2.3	7.0	12.0	19.7	238.0	142.0	104
Magnesium	3.0	30.0	11.9	15.9	167.0	210.0	59.8
Calcium	4.0	53.0	23.1	25.2	197.0	128.0	94.8
Silica	55.0	54.0	102.0	34.8	234.0	120.0	143
Alkalinity	*44.0	*61.0	29.0	52.0	34.0	*215.0	32.5
Chlorides	5.0	116.0	19.5	583.0	5225.0	5000.0	2380
Sulfates	*21.0	*55.4	184.0	52.8	620.0	*681.0	342
Total Dissolved Solids	125.0	533.0	480.0	1170.0	10200.0	8800.0	4270
pH	7.91	7.35	7.7	8.5	7.7	7.11	6.93
	*1960	*1961				*1960	

Semi-Annual Hydrologic Monitoring Program Report

Puna Geothermal Venture

August 2019 – First Sampling Event of 2019

Cardno

Shaping the Future

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Appendices

1 INTRODUCTION

Puna Geothermal Venture (PGV) operates a geothermal well field and electrical generation facility near the town of Pahoa, Hawaii. PGV's Geothermal Resource Permit Number 87 1, Condition 10, establishes guidelines for a hydrologic monitoring program that identifies and evaluates potential impacts of facility operations on nearby groundwater. The PGV project site is located in the Lower East Rift Zone (LERZ) of the Kilauea Volcano where the basal groundwater table, located approximately 600 feet (ft) below ground surface (bgs) in the PGV geothermal well field, is classified by the United States Environmental Protection Agency (USEPA) as a potential resource for drinking water. However, routine sampling indicates the basal groundwater in the LERZ is characterized by poor water quality and elevated temperatures. There are no public drinking water supply wells located in the LERZ and the County of Hawaii Department of Water Supply does not currently draw on the basal groundwater body in the LERZ for community water needs.

The objective of the Hydrologic Monitoring Program (HMP) is to monitor the basal groundwater in the vicinity of the power plant and well fields. The geothermal steam used to produce power at the PGV 38-megawatt (Mw) capacity power plant is derived from production wells drilled to depths of 4,000 to 4,500 ft bgs. During the power generation process, geothermal steam is used to drive the turbines that turn the electric generators. Then, the condensed steam and brine are reinjected into the ground to depths of 6,000 to 7,000 ft bgs via injection wells. These injection wells are operated under an Underground Injection Control (UIC) permit issued by the State of Hawaii Department of Health (HDOH). The HMP was designed to monitor any impacts of deep reinjection of geothermal fluids on basal groundwater in the vicinity of the water table.

Reports published by the United States Geological Survey (USGS) and the University of Hawaii (UH) summarize the potential impacts that leakage of geothermal fluids are expected to have on the shallow basal groundwater body (Thomas, 1987; USGS, 1994; Sorey and Colvard, 1994). Potential indicators include lowered pH values and increased water temperature, electrical conductivity, and salinity. Other chemical changes in the basal waters that would indicate geothermal fluid contamination include elevated levels of total dissolved solids (TDS), chloride, dissolved silica, bicarbonate (HCO_3^-), and sulfate (SO_4^{2-}). The semi-annual groundwater monitoring program measures these parameters, as well as additional dissolved inorganic constituents present in geothermal fluids. HDOH also requires PGV to monitor groundwater samples for volatile organic compounds (VOCs) and semi-volatile organic compounds (SVOCs), which are not expected to be present in geothermal brines.

The methodology for addressing potential basal water contamination by geothermal steam and brines was developed by Science Applications International Corporation (SAIC) in the PGV HMP of April 1990 (SAIC 1990). HDOH approved the HMP for use at PGV in May of 1990, which included the following tasks:

- identify and access appropriate monitoring locations;
- complete on-site monitoring wells;
- rehabilitate adjacent water wells;
- determine an initial background groundwater sampling profile; and

- conduct semi-annual monitoring, with semi-annual reports.

A summary of historical information relating to the HMP from 1990 to present is included in Appendix A, "Puna Geothermal Venture Project Profile."

In January of 2001, a hydrologic monitoring program was instituted as outlined in the USEPA, Region 9 UIC Permit, Class V Injection Permit No. HI598002. Appendix A of this permit requires sampling twice a year, once in January and once in July. Monitoring Wells (MWs) MW-1 and MW-2 were designated as the primary monitoring wells, with well MW-3 designated as the back-up well to be sampled in the event the primary wells could not be sampled.

In February of 2006, the HDOH UIC Permit Number UH-1529 renewal application was approved. Appendix A of this permit also required sampling twice a year, once in January and once in July. The sampling requirements are the same as those outlined in the USEPA Region 9 UIC permit.

A USEPA, Region 9 UIC permit modification action (Permit Number HI596002) was issued on September 9, 2009 and took effect on October 15, 2009, which also requires semi-annual groundwater sampling as stated in the 2006 HDOH UIC Permit renewal and the 2001 USEPA, Region 9 UIC Permit.

1.1 LAVA EVENT MAY 2018

On 30 April 2018, the Pu'u 'Ō'ō crater floor began to collapse, triggering earthquakes in the vicinity of PGV as the magma from Pu'u 'Ō'ō began to flow down the east rift zone. On 2 May 2018, cracks began to be reported from residents on roads in Leilani Estates. On Friday 4 May 2018, two large earthquakes struck the south flank of Kilauea volcano and fissures began to release lava in the Leilani Estates and Lanipuna Gardens subdivisions. The initial fissures were located southwest of the groundwater wells. On 6 May 2018 fissure 6 was located approximately 2,500 feet south of MW-2 (see Figure 1-1). Figures 1-1 through 1-5 depict the fissure development and proximities to the groundwater wells throughout the month of May 2018. Well MW-2 was consumed by lava on 18 May 2018 (Figure 1-3). Wells MW-1 and MW-3 were consumed by lava on 29 May 2018 (Figure 1-5).

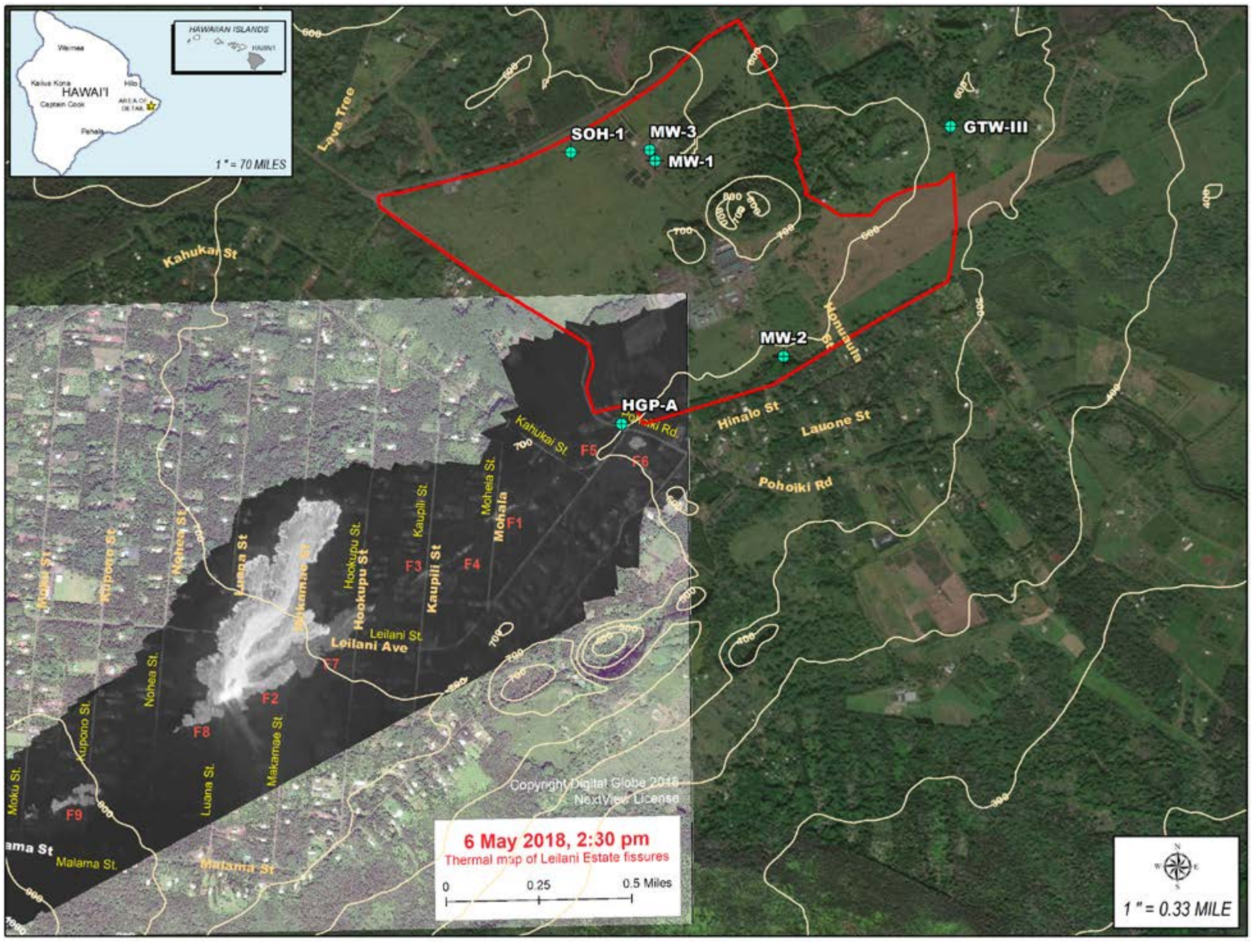

Figure 1-1 Well Location Proximity to Fissures 6 May 2018

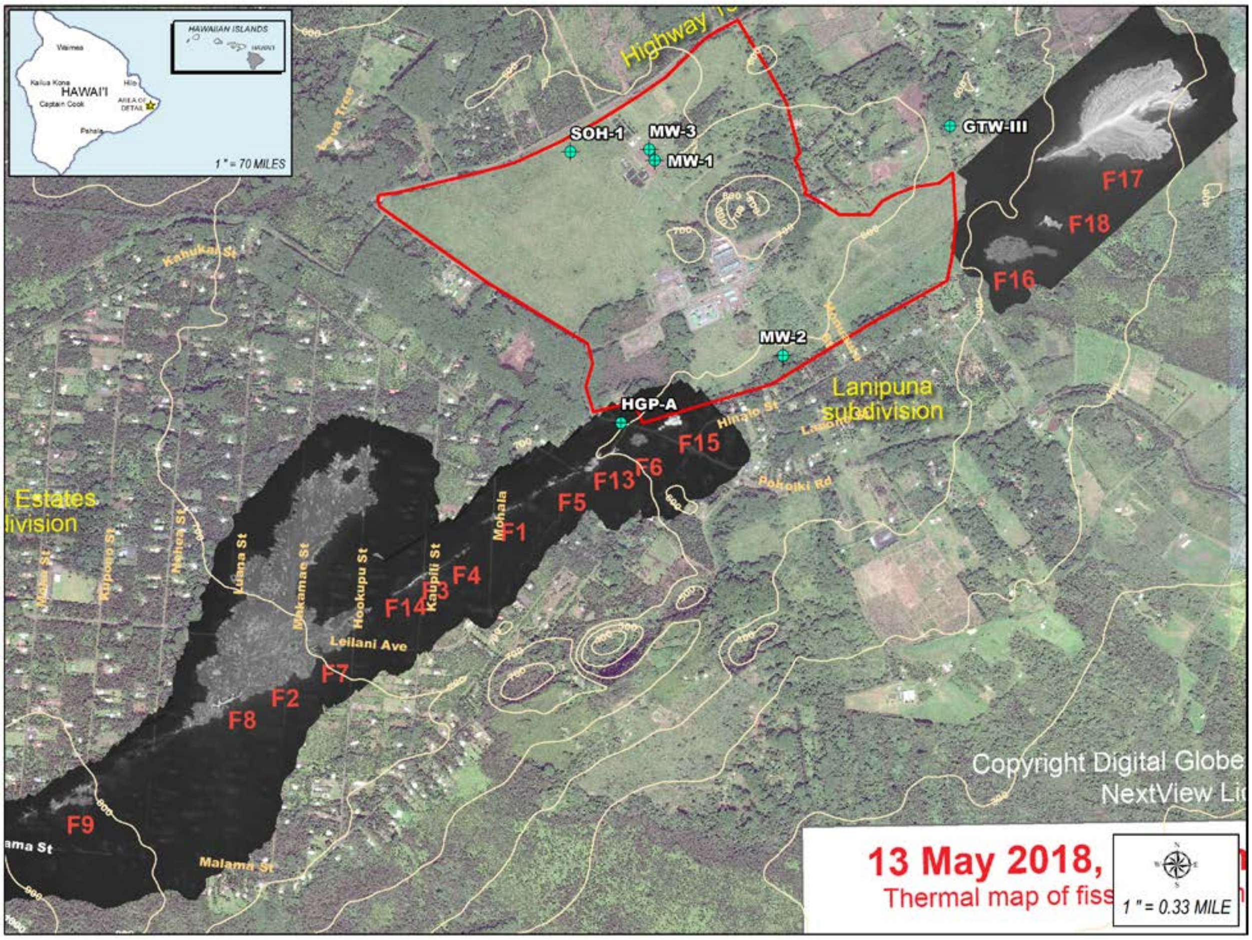

Figure 1-2 Well Location Proximity to Fissures 13 May 2018

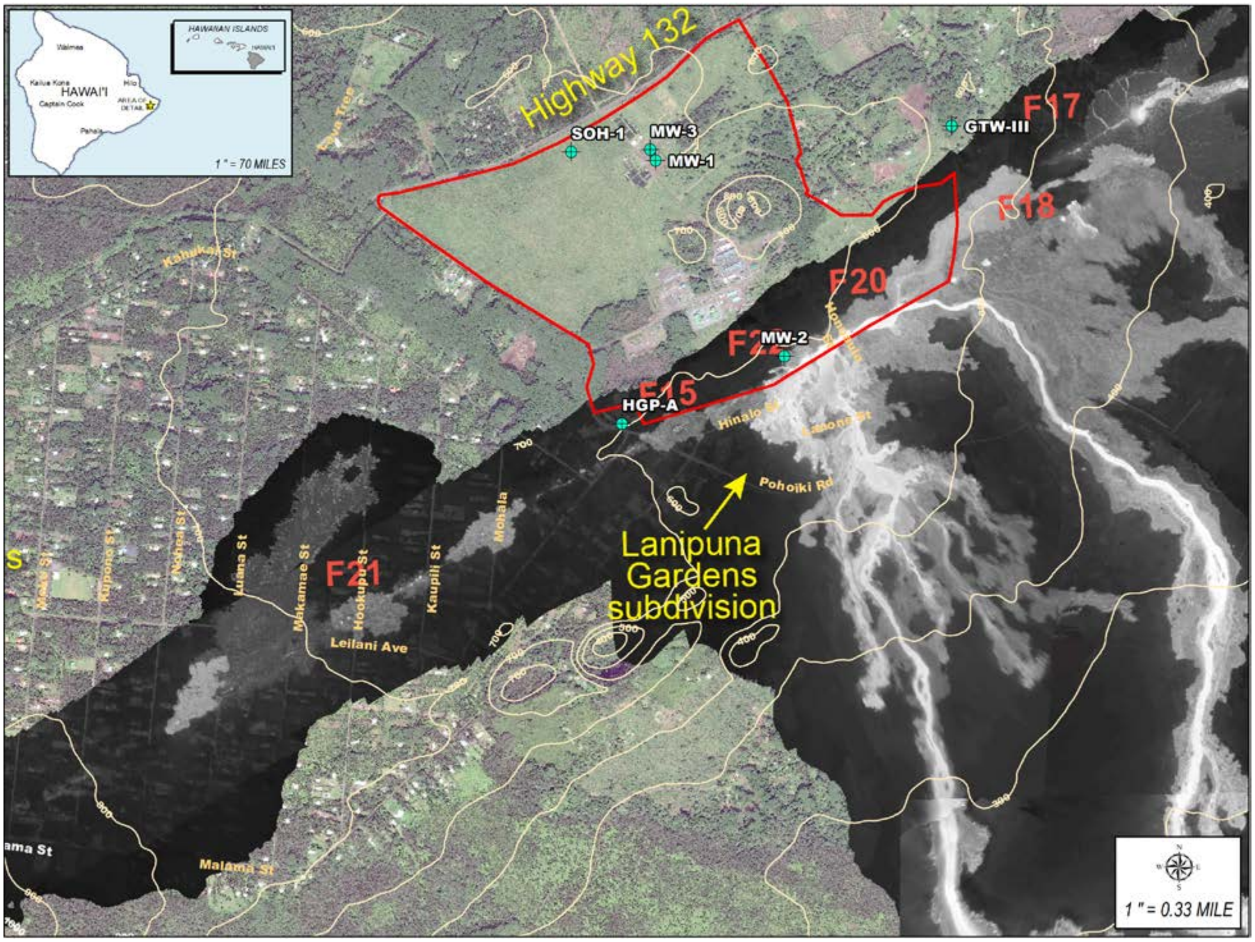

Figure 1-3 Well Location Proximity to Fissures 19 May 2018

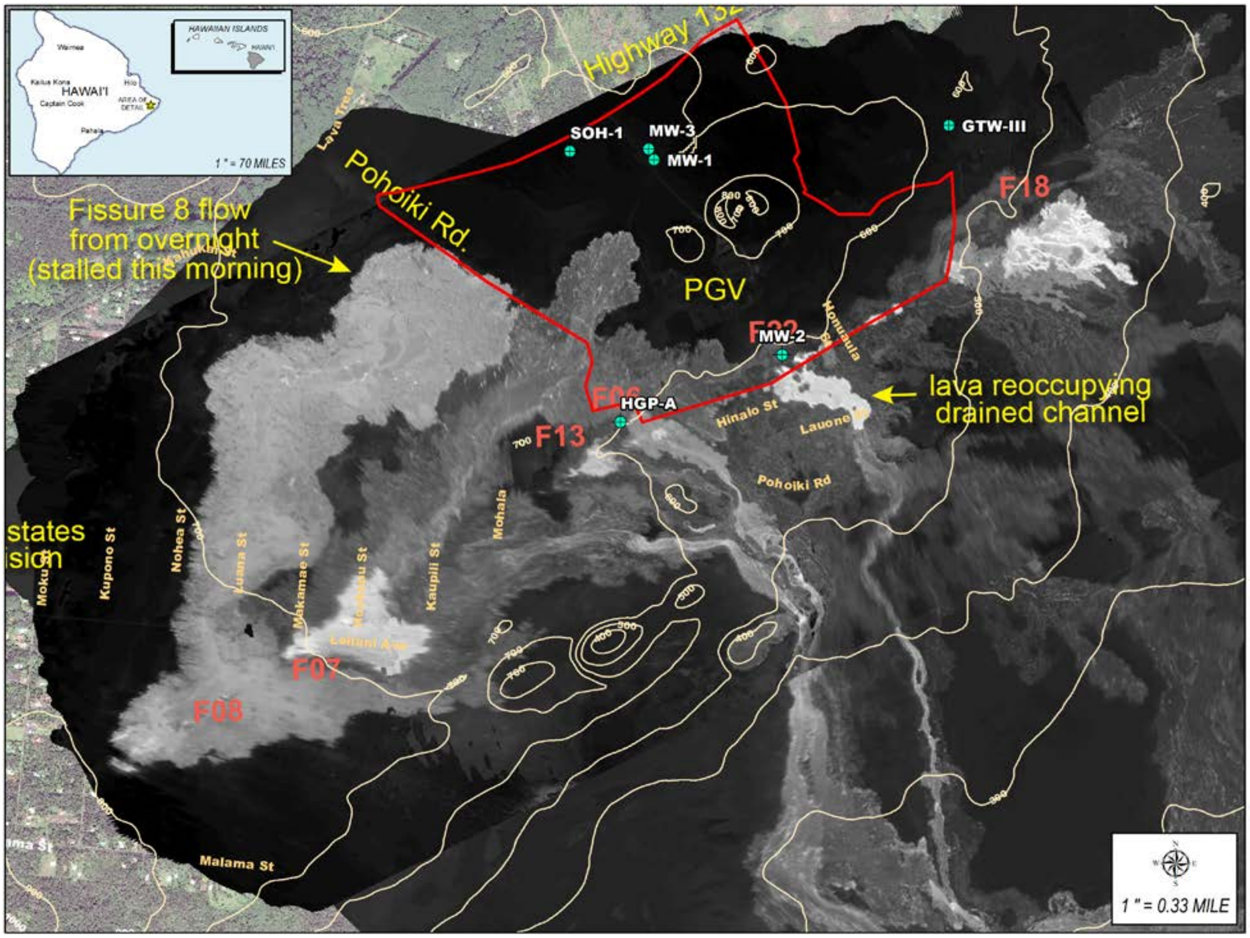

Figure 1-4 Well Location Proximity to Fissures 28 May 2018

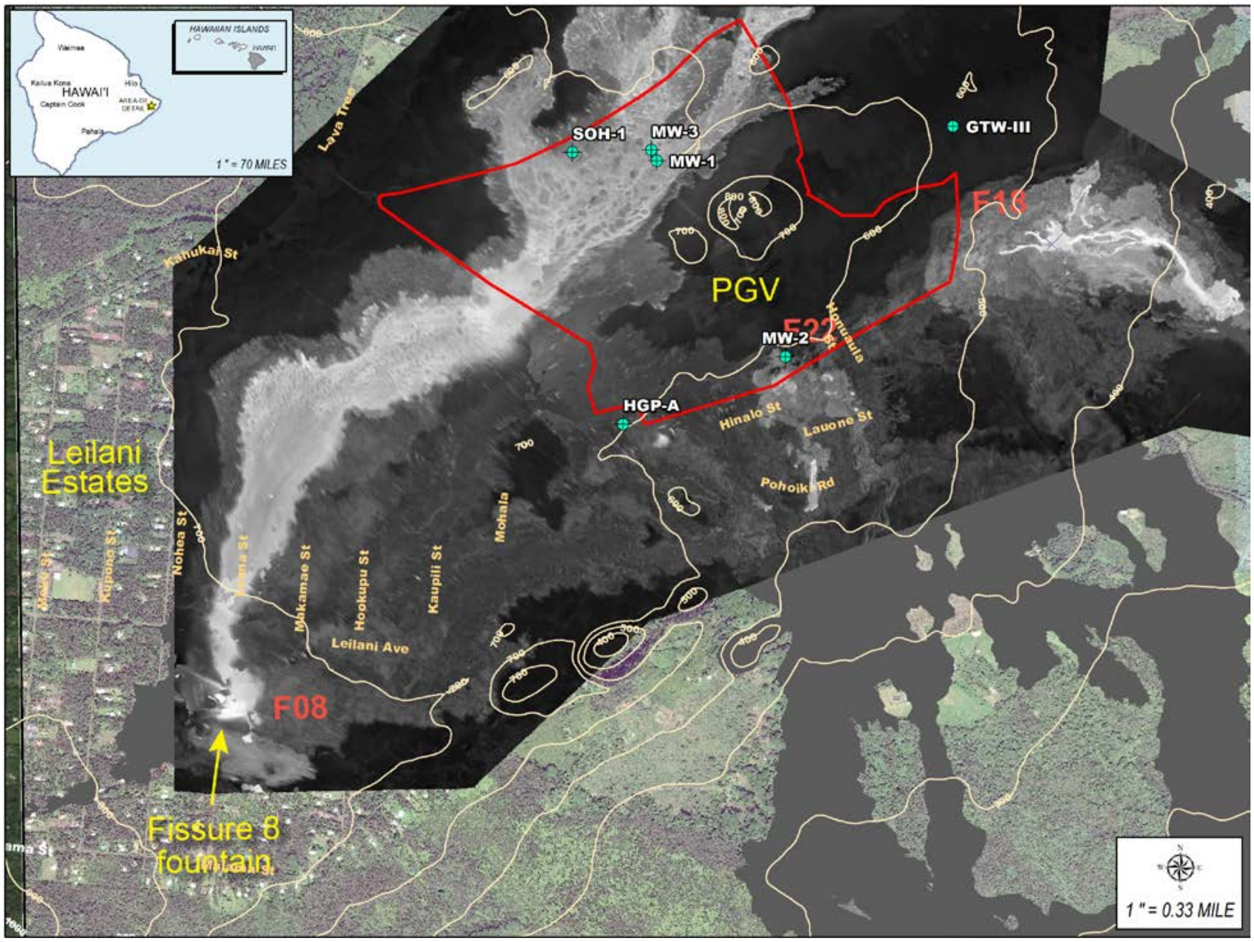

Figure 1-5 Well Location Proximity to Fissures 30 May 2018

1.2 PGV PLANT OPERATIONAL WELL MW-4

Due to the May 2018 lava event, all water wells on the PGV property were compromised (Figure 1-5). On 11 January 2019, Well Construction Permit for PGV MW-4 (Well No.8-2883-009) was approved. Well MW-4 was constructed to provide water to PGV for plant use, construction, and drilling activities. The well was drilled on 25 January 2019 and fully commissioned on 12 June 2019. The UIC wells related to MW-4 are not yet in operation; therefore, results of this sampling event represent baseline conditions prior to the UIC restart operations after the May 2018 lava event.

This semi-annual report summarizes the HMP observations and groundwater analytical results for the first sampling event of 2019 from MW-4. Section 2.0 of this report includes an overview of the sample identification numbers, the type of samples collected, and the sampling procedures used during these sampling events. Section 3.0 summarizes the specific sampling activities and findings from this sampling event. To aid in interpreting these results, an overview of the PGV environmental setting is provided in Appendix A; Chain of Custody records are provided in Appendix B; analytical laboratory data reports are provided in Appendix C.

Cardno GS, Inc. (Cardno) collected HMP field measurements and groundwater samples for the first sampling event of 2019 on 3 June 2019. Emax Laboratories Inc., in Torrance, California, provided analytical services. Since the HMP was initially developed in 1990, a number of different organizations have participated in its implementation at the PGV facility. A summary of the environmental monitoring contractors is provided in Table 1-1, below.

Table 1-1. Summary of Environmental Monitoring Contractors

Quarter	Environmental Contractor	Reporting Organization
Prior to 3rd Quarter 1994	SAIC, UH, and PGV	SAIC
3rd Quarter 1994 to 4th Quarter 1996	INTECH, Inc., UH, and PGV	INTECH, Inc.
3rd and 4th Quarters 1996	INTECH, Inc.	TEC
1997 to 2015	Cardno (TEC)	Cardno (TEC)
2016 to 2017	Lyons Associates, Inc.	LYON
2018 to present	Cardno GS, Inc.	Cardno

2 SAMPLING OVERVIEW

One groundwater-monitoring well (MW) was sampled on June 3, 2019 for the first sampling event of 2019, pursuant to UIC Permit Number UH-1529: MW-4.

MW-4 was constructed at Latitude 19° 28' 42.149 North, Longitude 154° 53' 7.246 West at the benchmarked elevation of 720.35 feet above mean sea level.

Well location is shown in Figure 2-1 Monitoring Well Location Map, below.

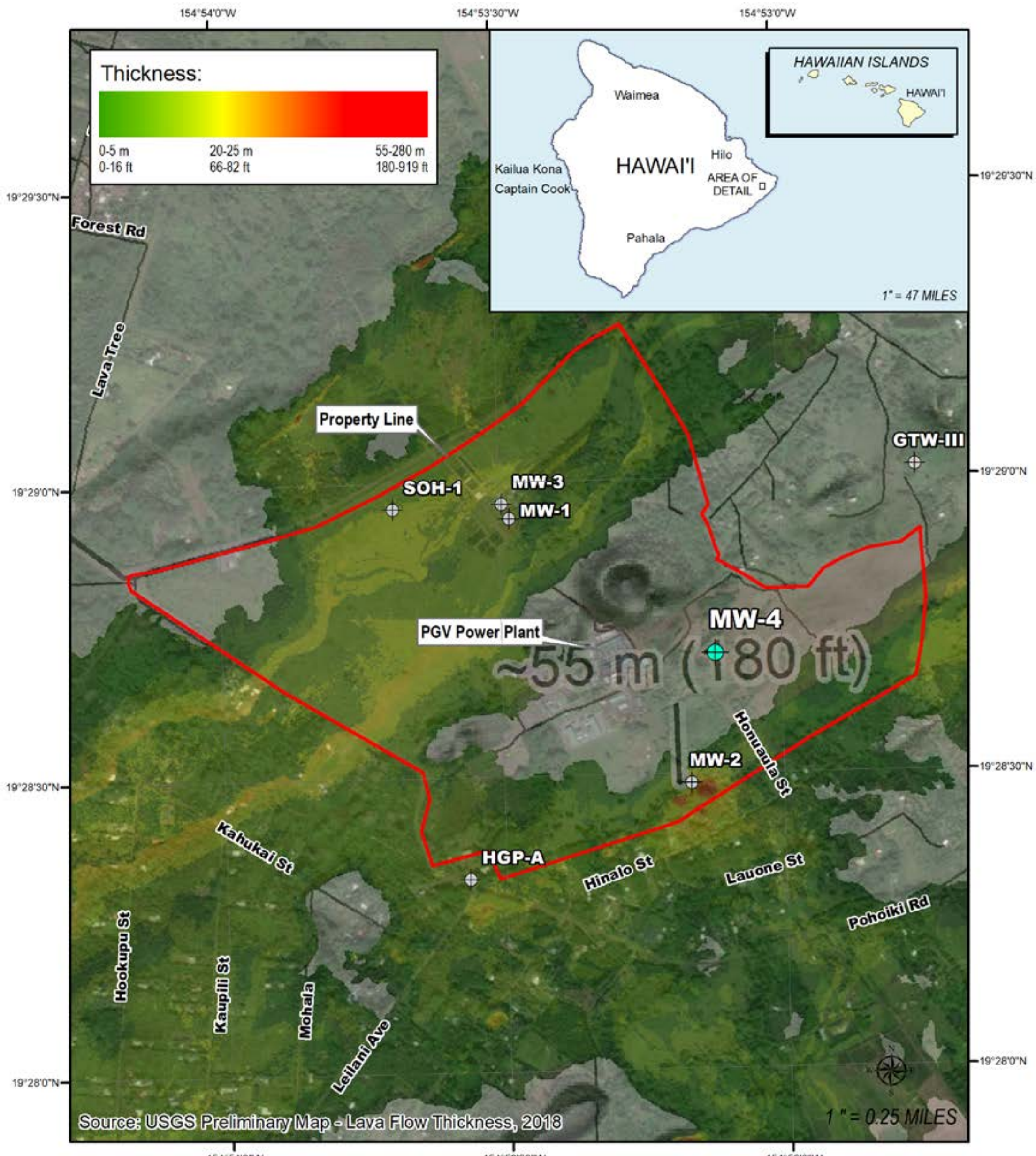

Figure 2-1 Monitoring Well Location Map

Quality control (QC) samples included a trip blank and a blind duplicate sample. Since only non-dedicated equipment was used when sampling these wells, equipment rinsate blanks were not submitted. Sample identification numbers, types, and analyses are summarized in Table 2-1.

Table 2-1. Monitoring Well Sampling Summary

Location	MW 4	MW 4 Duplicate	Trip Blank
Sample Number	**190104**	**190107**	**190108**
Sample Date	**06/03/19**	**06/03/19**	**06/03/19**
Field Measurements	X	X	
Specific Conductivity 120.1	X	X	
pH (Corrosivity) 150.1	X	X	
Bicarbonate Alkalinity 2320B	X	X	
Total Alkalinity 310.1	X	X	
Mercury 7470A	X	X	
Metals 6010B	X	X	
Silica 4500-SiO2C	X	X	
Reactive Sulfide SW846	X	X	
Reactive Cyanide SW846	X	X	
Ignitability SW1010	X	X	
TCLP Mercury 7470A	X	X	
TCLP Metals 1311/2011A/6010B	X	X	
Oil and Grease 1664	X	X	
Total Dissolved Solids 2540C	X	X	
Total Suspended Solids 2540D	X	X	
VOCs SW8260	X	X	X
TCLP Volatile Organics 1311	X	X	

Groundwater samples from the monitoring well were analyzed for a suite of selected inorganic and organic constituents. Inorganic compounds included 28 constituents, 16 of which have primary or secondary USEPA Maximum Contaminant Levels (MCLs) for community water systems (40 CFR 141.11). The remaining inorganic constituents required by the UIC permit are listed in the next section in Table 3-1. These inorganic constituents are included in the HMP because they are considered to be naturally associated with geothermal reservoirs and therefore serve as indicators of geothermal influence on groundwater quality. Organic analyses were conducted as well to measure VOCs and SVOCs as required by the HDOH.

2.2 SAMPLE COLLECTION PROCEDURES

This section briefly summarizes the sampling activities and methodology. Unless otherwise noted in this report, all field measurements and samples were collected using procedures defined in the approved HMP (SAIC 1990).

2.2.1 Water Level Measurements

Water level was not collected at monitoring well MW-4 because this well has a permanently installed pump, which prevents a water level measurement probe from being lowered down the well bore.

2.2.2 Water Quality Sampling and Analysis

MW-4 was sampled during the first monitoring event of 2019 to measure physical and chemical characteristics identified in the HMP. Sampling was conducted in accordance with USEPA protocols for groundwater sampling. The well is equipped with a down-hole pump. The well was sampled from a port on the corresponding pump's discharge line after a purge period in order to provide a representative sample of the formation groundwater. The stability of field parameters was verified by repeated field measurements. After purging, pH, electrical conductivity, temperature, and salinity were measured with a YSI ProPlus multi-parameter water quality meter, which was calibrated the night before sampling. The chloride content was estimated in the field from electrical conductivity using a function derived by a linear regression of historical chloride concentrations from laboratory analysis and electrical conductivity measurements. Sampling information and field measurements were recorded on field log forms. The sample aliquots to be analyzed for dissolved metals were filtered at the time of sampling by attaching a 0.45-micron filter directly to the well sampling port. Unless otherwise noted on the Chain of Custody form, in which case filtering was performed at the analytical laboratory.

Water samples were collected in the appropriate containers that were provided by the contract laboratory. Sample containers were labeled with the date, sample identification number, and type of analysis. The containers were then sealed, labeled, and shipped in sample coolers to the contract laboratory under strict chain-of-custody procedures. The analytical laboratory also analyzed pH and electrical conductivity.

A trip blank sample was submitted for QC purposes. The trip blank sample was prepared by the contract laboratory and shipped with the sample containers to PGV. The trip blank consisted of 40-milliliter (ml) glass vials with Teflon-coated septum sealed caps, containing distilled water acidified with hydrochloric acid. Trip blanks are used to evaluate potential sample contamination by VOCs during shipment. QC blanks are stored among and managed via the same techniques required of the monitoring well samples. A blind duplicate groundwater sample was obtained as a second sample from the well, identified as a "MW-7". This sample was given a unique sample number and analyzed in the same manner as the original well sample. Comparison of the analytical results of the two samples from the same well provides a quality assurance check on the analytical methods used in the laboratory analyses.

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3 FIRST GROUNDWATER SAMPLING EVENT OF 2018

Cardno personnel conducted groundwater sampling during the first sampling event of 2019 on June 3, 2019.

3.1 INORGANIC ANALYTICAL RESULTS

This section summarizes the analytical results of the inorganic constituents from the samples collected during the first sampling event of 2019. Inorganic constituents measured in the groundwater samples were compared with the MCLs or the National Secondary Drinking Water Standards (NSDWS) for community drinking water sources (Table 3-1). Although the basal groundwater in the Kilauea LERZ and south flank are considered a potential source of drinking water, the chloride levels and TDS concentrations generally have exceeded the NSDWS in past HMP sampling events, which are 250 and 500 milligrams per liter (mg/L), respectively. Any analytical result that exceeded primary or secondary drinking water standards is indicated in red bold in Table 3-1.

The purpose of the HMP is to assess any impact that the activities associated with geothermal energy production have on the shallow groundwater. Trends that would indicate geothermal injectate degradation of the shallow groundwater are:

- decreasing pH due to increasing dissolved gas concentrations;
- increasing sulfate concentrations due to oxidation of dissolved hydrogen sulfide (H_2S) gas;
- increasing bicarbonate alkalinity due to increases in dissolved carbon dioxide (CO_2) gas concentration;
- increasing concentrations of major ions (except magnesium) and total dissolved solids due to the higher concentrations in the geothermal injectate fluids; and
- decreasing magnesium to chloride ratios due to precipitation of magnesium in the geothermal reservoir.

This is the first sampling event since well construction for MW-4; therefore, the trends listed above were not analyzed.

Table 3-1, lists a summary of the inorganic analytical results.

Table 3-1. Groundwater Inorganic Constituents, First sampling event of 2019

	MW 4	MW 7 (Duplicate)	MCL or Secondary Standard	RL**	MDL	PD
Sample Number	190104	190107				(%)
Sample Date	06/03/19	06/03/19				
Arsenic	ND	ND	0.01	0.01	0.005	NA
Barium	0.0988	0.0977	2	0.01	0.002	0.3
Alkalinity	32.5	32.3		5.00	5.00	1.5
Boron	0.758	0.745		0.1	0.01	5.0
Bromide	7.19	7.29		0.5	0.25	NA
Cadmium	ND	ND	0.005	0.01	0.002	NA
Calcium	94.8	93.8		1.0	0.1	3.7
Chloride	**2380**	**2170**	250*	0.4, 20.0	0.2, 10.0	0.4
Chromium	ND	ND	0.1	0.01	0.003	NA
Copper	0.00804J	0.00684J	1.0*	0.01	0.003	NA
Cyanide	0.0186J	ND	0.2	0.02	0.015	NA
Fluoride	0.380	0.384	2.0*	0.1	0.05	1.1
Iron	0.275	0.266	0.3*	0.2	0.04	NA
Lead	**0.0325**	**0.0347**	0.015	0.01	0.003	9.4
Lithium	0.181J	0.179J		1	0.05	NA
Magnesium	59.8	59.4		1.0	0.1	3.4
Mercury	ND	ND	0.002	0.0005	0.0001	NA
Nickel	ND	ND		0.01	0.003	NA
Nitrate Nitrogen	0.0658J	0.0688J	10	0.1	0.05	0.7
Potassium	104	103		1.0	0.1	4.3
Selenium	ND	ND	0.05	0.05	0.025	NA
Silica	143	144		2.0	0.5	3.2
Silver	ND	ND	0.1*	0.01	0.003	NA
Sodium	1170	1160		1.0	0.1	4.2
Sulfate	**342**	**316**	250*	10.0	5.0	1.3
Sulfur, Total	120	120			2	1.3
Sulfide, Reactive	ND	ND		0.5	0.5	NA
Vanadium	0.00441J	0.00456J		0.01	0.002	5.1
Zinc	0.584	0.592	5*	0.02	0.01	NA
Conductivity	5960	6050		2.0	2.0	0.3
Ignitability	>212ºF	>212ºF		NA	NA	NA
pH	6.93	6.93	6.5-8.5*	NA	NA	0.7
TDS	**4270**	**3800**	500*	10.0	10.0	0.4

mg/L – milligrams per liter
MCL – USEPA maximum contaminant level for drinking water
RL – laboratory reporting limit
MDL – method detection limit
ND – not detected
NA – not applicable
J – Result is less than RL, but greater than MDL
PD – percent difference
* – Secondary Drinking Water Standard
** - If RL is different for MW-2, that value is listed second
Red bold values indicate quantities that exceed the MCL

3.2 ORGANIC ANALYTICAL RESULTS

The groundwater samples were analyzed for VOCs and SVOCs. A listing of organic compounds regulated by the USEPA in community water systems is presented in Table 3-3. The subcontracted laboratory analyzed the VOCs using Method 8260 and TCLP VOCs using Method 1311. Analytical results of VOCs and TCLP VOCs detected in the individual samples are reported in Appendix C. No VOCs were detected during the first sampling event of 2019 at MW-4 and MW-7 (Duplicate).

Table 3-3. USEPA MCLs for Organic Compounds in Drinking Water

Compound	µg/L		Compound	µg/L
Benzene	5		Styrene	100
Carbon Tetrachloride	5		Tetrachloroethene (PCE)	5
Chlorobenzene	100		1,2,4 Trichlorobenzene	70
1,2-Dichloroethane	5		1,1,1-Trichloroethane	200
Cis-1,2 Dichloroethene	7		1,1,2-Trichloroethane	5
Trans-1,2 Dichloroethene	100		Trichloroethene (TCE)	5
1,2 Dichloropropane	5		Toluene	1000
1,1-Dichloroethylene	7		Vinyl Chloride	2
Ethylbenzene	700		Xylenes (total)	10,000
hexachlorobenzene	1			
µg/L – micrograms per liter MCL – EPA maximum contaminant level for drinking water				

3.3 QUALITY ASSURANCE/QUALITY CONTROL SAMPLE RESULTS

Quality assurance/quality control (QA/QC) samples for the first sampling event of 2019 included three trip blanks and a duplicate sample from MW-4. There was good agreement between the primary sample from MW-4 and the duplicate sample, with all differences being less than 15 percent. The trip blanks were analyzed for VOCs only.

3.4 FIELD MEASUREMENTS

Table 3-4 summarizes the field measurements during the first sampling event of 2019. Subsequent reporting of MW-4 will allow a comparison of the field measurements.

Table 3-4. Field Measurements, First sampling event of 2019

Sample Location	Sample Date	pH	Conductivity (µS/cm)	Salinity (o/oo)	Chloride (mg/L)	Temp. (°C)	Water Level (ft amsl)
MW-4	06/03/19	6.9	6000	NT	2250	80	NT
µmhos/cm – micro Seimens per centimeter NT – not taken o/oo – parts per thousand							

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4 SUMMARY AND CONCLUSIONS

The groundwater in the lower Puna area on the flanks of Kilauea Volcano has been classified into six groundwater types on the basis of temperature and chloride (Cl^-) concentrations (USGS, 1994).

Type I – Cold (<25 °C), dilute (Cl^- 10 mg/L);

Type II – Cold (<25 °C), brackish (Cl^- 75-300 mg/L);

Type III – Warm (~ 40 °C), dilute (Cl^- ~20 mg/L);

Type IV – Warm (~ 40 °C), brackish (Cl^- 100-800 mg/L);

Type V – Hot (50-100 °C), saline (Cl^- >1,000 mg/L); and

Type VI – Warm (30-40 °C), saline (Cl^- >1,000 mg/L).

The groundwater in PGV on-site monitoring well, MW-4, is classified as Type V (based on latest analytical analysis), with temperatures of 80 °C and high chloride concentration. This well is composed of warm saline water heated by geothermal steam from below. The geothermal steam contains elevated levels of H_2S, contributing to high sulfate levels in MW-4.

Since this is the first sampling event at MW-4, a comparison of historical results is not possible. As stated in Section 3, the geochemical indicators of most value in detecting injectate contamination from geothermal power production include (Thomas 1987):

- increased water temperature;
- decreased water pH levels;
- increased sulfate and alkalinity (resulting from increases in H_2S and carbon dioxide (CO_2) from geothermal steam);
- increased concentrations of dissolved silica, chloride, and major cations (sodium, potassium, and calcium);
- increased TDS in well waters; and
- unexplained increases in water level.

Of the constituents analyzed, sulfate and magnesium may be the most diagnostic. Sulfate and magnesium concentrations in MW-4 are indicative of geothermal influences and seawater intrusion. Geothermal steam contains H_2S concentrations of approximately 900 milligrams per kilogram (mg/kg), which oxidizes to sulfate in the basal groundwater (Thomas, 1987). Geothermal-steam heating of the shallow groundwater results in elevated temperatures, as well as elevated concentrations of sulfate in the well waters. Seawater sulfate may be distinguished from geothermal sulfate by the presence of corresponding levels of seawater-derived chloride. In seawater, the sulfate to chloride ratio is 0.14. Sulfate to chloride ratios above 0.14 indicate geothermal-steam heating of the shallow groundwater. Geothermally-altered water becomes depleted in magnesium due to its precipitation as magnesium oxysulfate (Thomas, 1987). The seawater magnesium to chloride ratio is approximately 0.07; a decrease from this value would indicate geothermally altered water.

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Appendix A

Puna Geothermal Venture Project File

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Description

The Puna Geothermal Venture (PGV) site is an elongated, roughly diamond shaped parcel, approximately 500 acres in size, located on Kilauea Volcano's Lower East Rift Zone (LERZ) (Figure A-1), three miles southeast of the town of Pahoa, and 25 miles south-southeast of the city of Hilo, on the eastern side of the Island of Hawaii. The site is bordered on the north-northwest by State Highway 132 (Kapoho-Pahoa Road) and on the south-southwest by Pahoa Pohoiki Road. The eastern boundaries border on privately owned properties. The borders of the site are located at an elevation of approximately 540 to 600 feet (ft) above mean sea level (amsl). The area surrounding the site is primarily rural with some residential and agricultural development. Lava Tree State Park and the Nanawale Forest Reserve border the site to the north. The State of Hawaii Natural Energy Laboratory of Hawaii (NELH) research center and demonstration geothermal electrical generation facility were located adjacent to the southwest corner of the property (these structures were consumed by lava in May 2018 (see Section 1.1). The Hawaii Geothermal Permit – Well A (HGP-A) geothermal well on the NELH site produced 3 megawatts (Mw) of electricity from 1982 to 1989, and was plugged and abandoned in June 1999. Two sparsely settled subdivisions, Lanipuna Gardens and Leilani Estates, are located across the Pahoa Pohoiki road south of the PGV site.

The dominant geological feature at the PGV site is Pu'u Honuaula, a large cinder cone which rises approximately 240 feet above its environs. Vents from Kilauea's 1955 eruption are located near the eastern and western borders of the site, and a prehistoric vent, Pu'u Pilau, is located near the southern border. Numerous fissures strike east west, parallel to the LERZ, through the site. See Section 1.1 for descriptions of the May 2018 lava event.

The 30-Mw PGV geothermal electrical generating plant is located on the south side of Pu'u Honuaula in a small saddle between the main vent and an auxiliary vent to the west (Figure A-1). The main plant site contains all the energy transfer and electrical generation facilities. Up to six smaller satellite sites may be developed around the plant as drilling pads for production, injection, make up water, and monitoring well sites. Currently the plant is supplied by three wells located on Pad A, KS-9, KS-10, and newly installed well KS-11. The plant, six well pads, and associated piping will eventually occupy approximately 25 acres of the site.

Background

In September 1989, the County of Hawaii Planning Commission approved a Geothermal Resource Permit Application (GRP) 87 1 to proceed with the development of a 25-Mw geothermal electrical generating facility at the current project site. Plant construction commenced in early 1990, with completion of the generating facility in mid-1991. The construction of the geothermal production wells began in February 1991 and the facility came on line in April 1993. As stipulated in the GRP, the Hydrologic Monitoring Plan (HMP) was initiated in February 1991 to coincide with the start of drilling. At that time, six wells were identified as being completed in the shallow aquifer south or east, and potentially down gradient, of the PGV site. These wells were Allison, GTW III, GTW IV, Kapoho Airstrip, Kapoho Shaft, and Malama Ki (Figure A-2). Of these wells, only Kapoho Shaft has been used as a water supply well; that use was terminated in 1995. GTW III, Kapoho Shaft, and Malama Ki wells were selected for the monitoring program based upon their location and accessibility. Quarterly sampling of Kapoho Shaft was discontinued in 1996. GTW III, completed to a depth of 690 ft below ground surface (bgs), is located on the crest of the LERZ about one half-mile east of the PGV site at an elevation of 563 feet above mean sea level (ft amsl). GTW III was a partially cased well with a blockage or deviation at approximately 270 ft bgs. Permission to clean out this well was granted to PGV and completed between the initial well sampling and the second quarterly round of sampling. Further rework of GTW III was completed in the winter of 1991 with the installation of a temporary casing to facilitate sampling. Malama Ki, an exploratory well completed to a depth 316 ft bgs, is located approximately one mile south of the PGV site at a surface elevation of 274 ft amsl on the Malama Ki University of Hawaii Agricultural Research Station approximately four miles southeast of the PGV site. GTW III and Malama Ki were sampled with a reusable bailer.

During the well field drilling program, PGV completed three on-site water wells (Monitoring Well [MW]), MW-1, MW-2, and MW-3 (Figures A-1 and A-2). Two of these wells were chosen for the HMP based upon their locations; MW-1, located in the northern portion of the site in a storage yard, and MW-2, located in the southern portion of the site, south of Pad F. MW-1, at an elevation of 610 ft amsl, taped groundwater at 655.6 ft bgs through a downhole electric pump. The pump became inoperative in February 1991, and MW-3, located just north of MW-1 and completed to approximately the same depth, was substituted for MW-1 in the HMP. MW-1 became operational again in late 1992 and was reinstated in the HMP in the January 1993 quarterly sampling round. It was sampled on a quarterly basis until the spring of 1994 when the pump again failed and MW-3 was then substituted for MW-1 in the HMP. MW-3 was substituted for MW-1 in November 1999 during the 4th quarter 1999 HMP sampling event. MW-1 was reinstated in the HMP in the February 2000 quarterly sampling round. MW-2, at an elevation of 588 ft amsl, taps groundwater at 596 ft bgs and was accessed by bailer until installation of a downhole pump in January 1998.

Pahoa Battery 2A is the up gradient well chosen for the HMP. It is a County of Hawaii Department of Water Supply (DWS) well for the town of Pahoa and is located north of the LERZ, approximately three miles northwest of the PGV site, and has an elevation of 715 ft amsl. This well taps ground water at approximately 765 ft bgs (Figure A-2). Sampling is done with a downhole electric pump. In November 1999 the pump in Pahoa 2A became inoperative and Pahoa 1, which is located on the same well pad as Pahoa 2A, was substituted for Pahoa 2A in the 4th Quarter 1999 HMP sampling event. Pahoa 2A became operational again in early 2000 and was reinstated in the HMP in the February 2000 quarterly sampling round. In 1996, with the removal of the Kapoho Shaft from the HMP, Keonepoko Nui, a DWS well about five miles northwest of the PGV site was added. This well, up gradient of the PGV site, is located at an elevation of 606 ft amsl and was completed to a total depth of 640 ft bgs.

In January of 2001, a hydrologic monitoring program outlined in the U.S. Environmental Protection Agency, Region Underground Injection Control (UIC) Permit, Class V Injection Permit No. HI598002 was instituted. Appendix A of this permit requires sampling twice a year, once in January and once in July. Wells MW-1 and MW-2 were designated as the primary monitoring wells, with wells GTW-III and Malama Ki (consumed by the May 2018 lava event) set aside to be sampled in the event that the primary wells could not be sampled.

GTW-III was inaccessible due to the May 2018 lava event.

Geology

The Island of Hawaii currently overlies the Hawaiian hot spot at the southeastern end of the Hawaiian Archipelago. It is composed of five basaltic shield volcanoes, Kohala, Mauna Kea, Hualalai, Mauna Loa, and Kilauea. Kilauea is the youngest and most active of Hawaii's volcanoes; it is an undissected tholeiitic shield with a summit caldera having well-defined east and southwest rift zones. Over 90% of its eastern flank is younger than 1,100 years. Kilauea has been in constant eruption on its upper east rift zone since 1983 (Figure A-3). Kilauea's east rift zone (ERZ) initially trends southeast for four miles from the summit caldera then turns east and extends another 28 miles to Cape Kumukahi where it enters the sea and continues another 44 miles as a submarine ridge. The ERZ has historically been Kilauea's most active rift. Its surface expression is characterized by pit craters and small lava shields on the upper and middle east rift zone (UERZ and MERZ), and cinder cones and occasional tuff cones on the MERZ and LERZ (Figure A-3). Large fissures and grabens are common along the entire length of the east rift, and subsurface thermal activity is evidenced by numerous steam vents, which discharge at atmospheric pressure.

The present study has focused on the Kilauea LERZ from the area around Pu'u Honuaula to Cape Kumukahi and the north and south flanks of Kilauea that are adjacent to this part of the LERZ. This area is located within the district of Puna. The region is covered by lavas of the Puna volcanic series ranging in age from 1,500 years to those erupted in 1960, and consists of numerous thin a'a and pahoehoe flows that are extremely permeable due to their high vesicularity, cooling joints, interflow joints, a'a clinker layers, and lava tubes.

The dominant structural feature in the study area is the LERZ, which forms a topographical high that is 2.5 to 3.7 miles wide and studded by six major cinder cones and a large tuff ring near its eastern terminus at Cape Kumukahi. There are also numerous minor eruptive vents, fissures, and grabens aligned parallel to the strike of the rift. Southwest of Pu'u Honuaula a northwest trending strike slip fault intersects the LERZ at approximately a right angle.

Eruptive vents formed within the study area during Kilauea's 1955 and 1960 eruptions (Figure A-3). The 1955 vents south of Pu'u Honuaula and the 1960 vents in Kapoho were sites of violent phreatic explosions when the eruption of lava from them had ceased. Kapoho Crater, a large tuff ring near Cape Kumukahi, and Pu'ulena, a large tuff crater southwest of Pu'u Honuaula, are evidence of large prehistoric phreatomagmatic eruptions.

Intrusive bodies are common throughout the subsurface of the Kilauea ERZ, and where they have broken the surface in eruption, they form the cinder cones and vents of the rift. However, a far greater percentage remain below the surface where they solidify as tabular dikes with strikes generally parallel to the axis of the ERZ and dips that average 60 to 80 degrees from horizontal. These bodies form a coherent dike complex, which is the subsurface expression of the ERZ. Gravity mapping indicates that the LERZ dike complex widens with depth, as a high-density mass extends 2.5 kilometers (km) south to 6.2 miles north of the rift zone, with a depth of 1.2 miles on its southern edge to almost 2.5 miles on its northern boundary. Evidence from deep drill holes also indicates that the entire length of the core of the LERZ is hot at this depth with an approximate temperature of 350°C.

Since dikes solidify under high lithostatic pressure, they are almost always avesicular and do not develop the cooling joints found in surface lavas. Therefore, their permeability is much less than the highly vesicular, densely jointed lava flows, which they intrude. This difference in morphology and the discordant orientation of dikes effectively allows them to partition the ERZ into compartments of highly permeable lava flows separated by relatively impermeable dikes. Deposition of secondary minerals and alteration of basalts to clay minerals by hydrothermal fluids also contribute to a reduction in permeability within the LERZ by sealing fractures and voids.

Data from a deep core hole, SOH-1, has shown that the subsurface structure of the LERZ in the study area near Pu'u Honuaula consists of numerous extrusive lava flows as well as intrusive dikes. A series of a'a and pahoehoe flows interbed to a depth of approximately 2,460 feet below sea level. Below them lies a 1,640 feet thick transition zone of mixed hyaloclastites and pillow lavas, which grade into a basement of deep submarine pillow lavas. Although the upper 2,460 feet of the section is extremely permeable, the change in morphology at the transition zone, increasing lithostatic load, and increasing secondary mineral precipitation and alteration from increasingly hot fluid circulation, rapidly decrease permeability below the transition zone. Permeability below the transition zone is fracture dominated secondary permeability, which has developed as the result of forceful injection of dikes into the rift zone and the seaward slippage of Kilauea's unbuttressed south flank.

Hydrology

The youthful age of the Kilauea volcano has directly affected its hydrology. Deep soils and valleys have not had time to develop, and extremely porous lavas remain at or very near its surface. Consequently, there is no run-off from the high precipitation that falls on the volcano, and Kilauea does not support perennial streams. Rainfall is returned to the atmosphere as evapotranspiration or infiltrates to groundwater. Groundwater flow generally follows surface topography, flowing down gradient to eventually exit as coastal springs and diffuse seeps. The average volume of groundwater discharged from these basal springs between Hilo and Kalapana is estimated to be approximately 215 billion liters per year. Due to the high permeabilities and extremely high recharge rates, groundwater residence times are short. A recent tritium dating study yields residence times for well and spring waters within the study area between 10 to 18 years or 15 to 20 years, depending on whether a well-mixed or piston flow model is used.

Three types of groundwater are present within Kilauea (Figure A-4). First, there is a minor component of water that is perched on less permeable material. In the study area, perched water occurs in the tuff underlying Kapoho Crater, the Green Lake within the crater (no longer exists due to the May 2018 lava event), and the Kapoho Shaft well east of the crater (Figure A-2). Dike impounded water is present under the summit of Kilauea and within the ERZ, where the relatively impermeable dikes dam water that infiltrates the permeable lavas. Wells drilled in the LERZ study area show large fluctuations in static water level over small areas, but heads in the LERZ are generally lower than in the groundwater levels north the rift zone and higher groundwater levels south of the rift zone, as measured in wells at the same distance from the coast. GTW III (well within the LERZ) tap dike confined waters (Figure A-2). The largest component of Kilauea's groundwater outside of the LERZ is basal water, which exists as a lens shaped fresh water body floating on the salt water that permeates the island below sea level. Pahoa 1, Pahoa Battery 2A, and Keonepoko Nui tap basal water north of the LERZ and Malama Ki taped basal water south of the LERZ (Figure A-2).

Groundwater flux within Kilauea is controlled by the amount of rainfall received, hydraulic gradient, permeability of the lava flows, and subsurface geological structures. Horizontal and vertical groundwater flow takes place in Hawaiian lavas through interconnected vesicles, cooling joints, interflow contact layers, fissures, faults, and lava tubes. On the flanks of the volcano, outside the rift zones, horizontal flow is dominant due to the more or less horizontal emplacement of lava tubes and interflow breccias; however, within the rift zones, fissures and faults increase the efficiency of vertical flow.

The north flank adjoining the ERZ receives a large groundwater flux traveling down gradient from the upper slopes of Kilauea. Basal groundwater underlies the north and south flanks of Kilauea, both within the study area. However, the basal lens is only well-established on the north flank. Wells drilled at elevations of less than 1,000 feet on the north flank have encountered a more than 300-foot thick lens, which thins as the coast is approached.

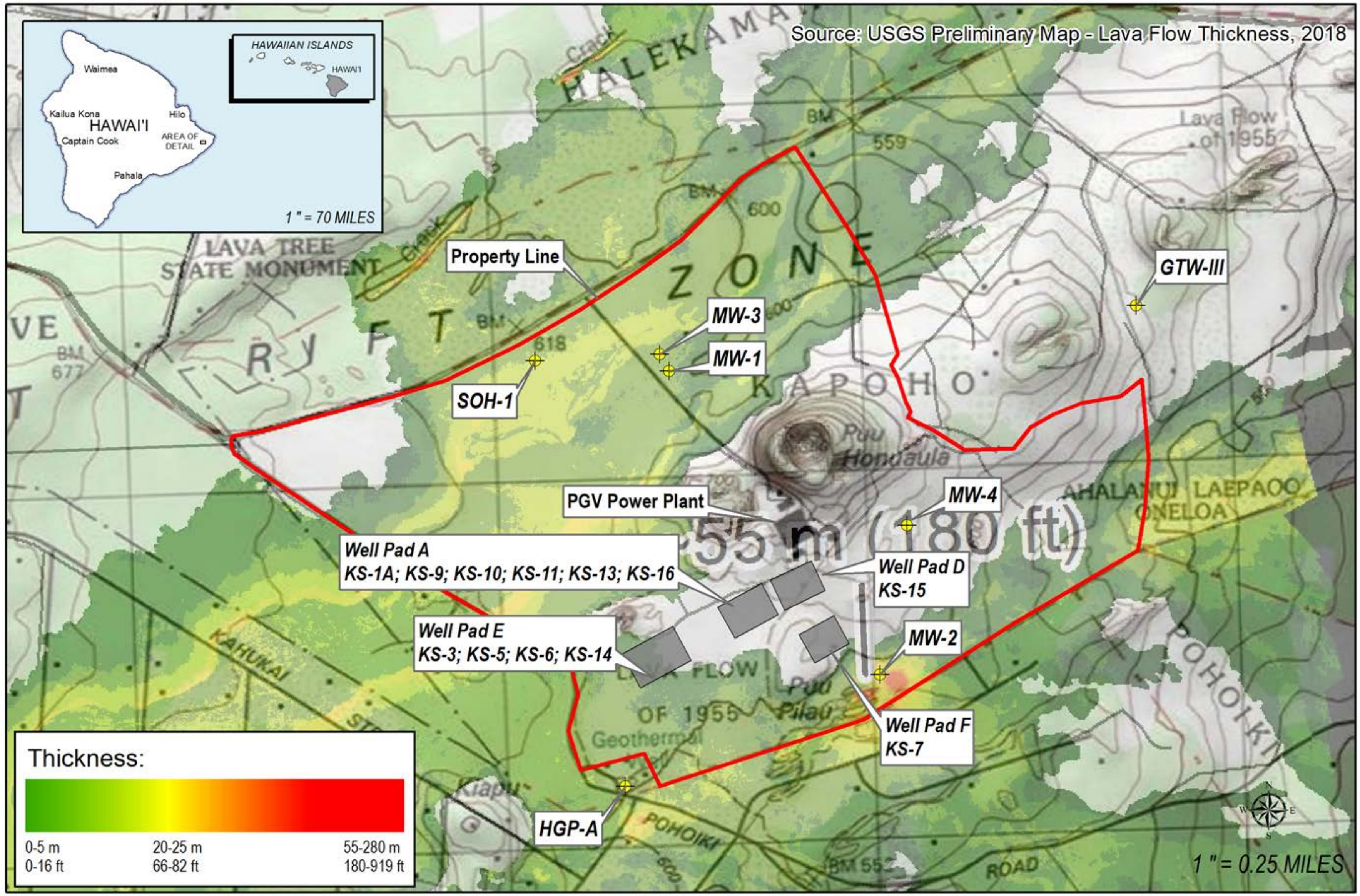
The low permeability of the dike complex within the ERZ impedes the flow of groundwater from Kilauea's north flank into and through the rift. Groundwater within the ERZ is derived predominately from infiltration of precipitation, which falls on the rift zone where large fissures efficiently channel meteoric recharge to depth. This water encounters the hot rocks of the subaerial submarine transition zone and is convectively returned to the top of the water table. Groundwater temperatures in wells in the LERZ are well above ambient recharge temperature, ranging from 40^{o} C previously in MW-1 to 93^{o} C in GTW III.

The Kilauea south flank derives its groundwater from direct infiltration and overflow or throughflow from dike compartments in the ERZ. Overflow of warm brackish water along the southern edge of the LERZ has substantially degraded the basal lens in the lower south flank. In the LERZ, saline water rises convectively to the surface of the basal lens, where it forms a broad plume of warm water that floats on fresher, cooler basal water below, and is eventually discharged at the coastline as numerous warm springs and seeps. Lower south flank wells also show elevated temperatures; water in Malama Ki, 1.9 km from the LERZ, was 55°C. Heads in lower south flank wells are lower than those at the same altitude on the north flank. The dike complex of the ERZ acts as a hydraulic barrier between the north and south flanks. This barrier, as well as the smaller area and substantially lower rainfall of the south flank (75 inches per year versus 125 inches per year for the north flank), results in lower hydraulic head.

Hydrogeochemistry

Just as the study area may be divided into geological and hydrological provinces of north flank, LERZ, and south flank, groundwater in the area may be geochemically divided into north flank waters, LERZ waters, and south flank waters. Dissolved solid concentrations are typically quite low in north flank waters, having an average of 100 mg/L or less in the interior portion of the basal lens, but increasing to >200 mg/L to the east, as the coast is approached. Total dissolved solids (TDS) concentrations also increase toward the south as wells encounter water influenced by the LERZ, and mixing of seawater near the coastline. The dominant anion/cation pairs in north flank waters are sodium bicarbonate ($NaHCO_3^-$) and calcium carbonate ($Ca(HCO_3)_2$), but grade to sodium chloride near the coast. Dissolved silica concentrations are low on the north flank, approximately 30 mg/L, but increase by 50 to 75 percent as the LERZ is approached. Pahoa Battery 2A, a typical north flank well not far from the LERZ, has an average chloride concentration of 6.0 mg/L and an average silica concentration of 49.9 mg/L.

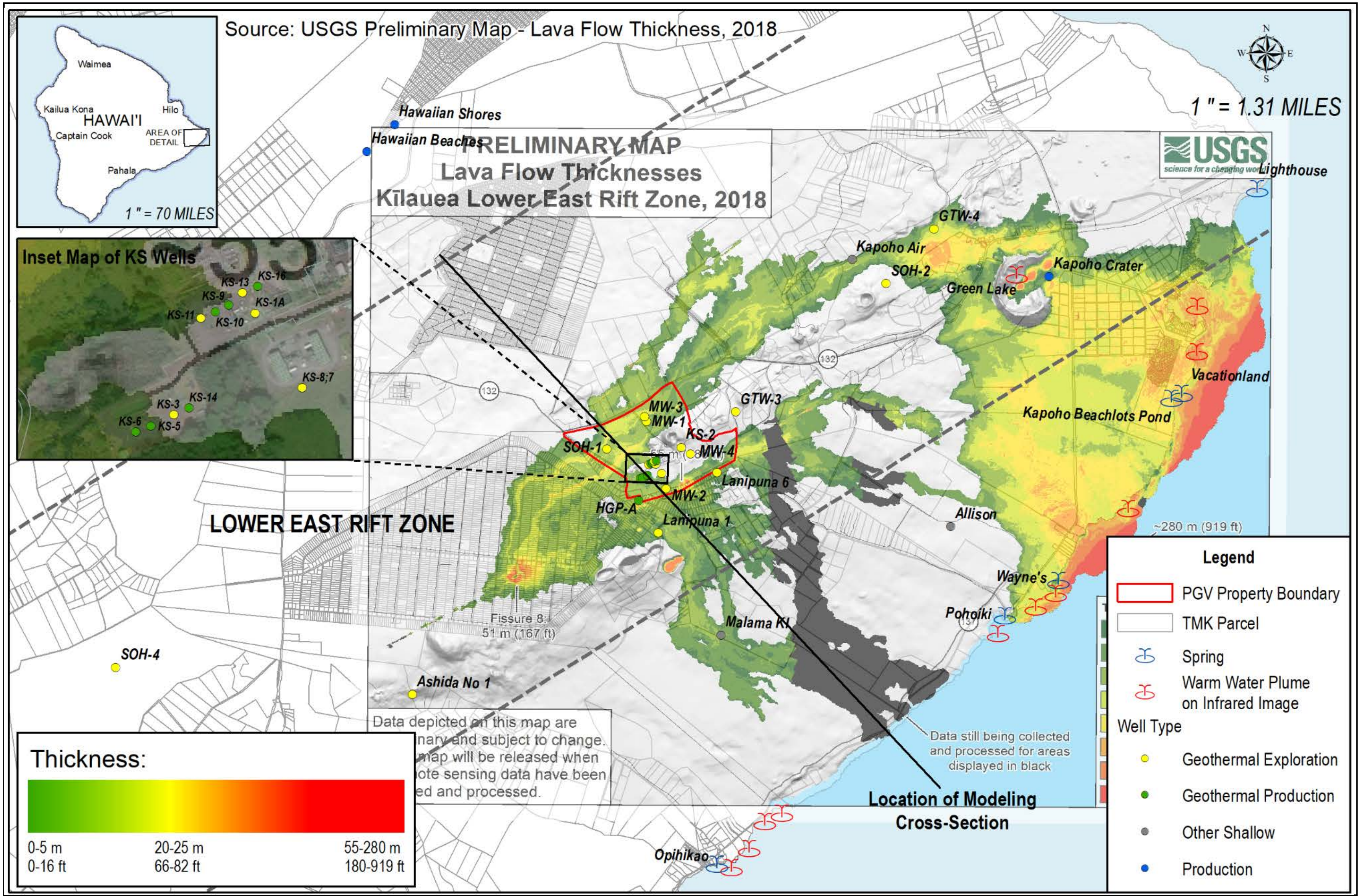
The geochemistry of LERZ waters is more complicated, and the chemical compositions TDS span a broad range. Sodium chloride is the dominant cation-anion pair present in LERZ waters, but it does not appear to uniformly increase with proximity to the coast. Chloride concentrations range from an average of 364 mg/L in Kapoho Airstrip well, located 3 miles from Cape Kumukahi at 287 ft amsl, to an average of 5,314 mg/L in GTW III, located 5.2 miles from Cape Kumukahi at 656 ft amsl. There is, however, some evidence that chloride (Cl^-) concentrations increase from north to south across the LERZ. MW-1 and MW-3 drilled on the north side of Pu'u Honuaula, had average chloride concentrations of 15 and 16 mg/L respectively, whereas MW-2, drilled on the south side of Pu'u Honuaula, had an average chloride concentration of 903 mg/L. MW-4 was also drilled on the south side of Pu'u Honuaula, and results from the first sampling event support this as chloride concentration was 2380 mg/L. Silica concentrations vary considerably in LERZ waters, but all are above the 49 mg/L average for non-thermal Hawaii island waters estimated by McMurtry, et al., (1977). The geochemistry of waters in the lower south flank of Kilauea is strongly influenced by overflow from the LERZ dike complex and mixing with seawater. As in the LERZ, sodium chloride is the dominant cation anion pair. Chloride concentrations are higher closer to the LERZ than to the coast. Malama Ki had an average chloride concentration of 281 mg/L 1.2 miles from the coast. Silica concentrations also decrease with distance from the LERZ. Malama Ki had a silica concentration of 120 mg/L, while the Allison well contains 24.1 mg/L.



Cardno

Figure A-1. Map of Area of Review – Puna Geothermal Venture

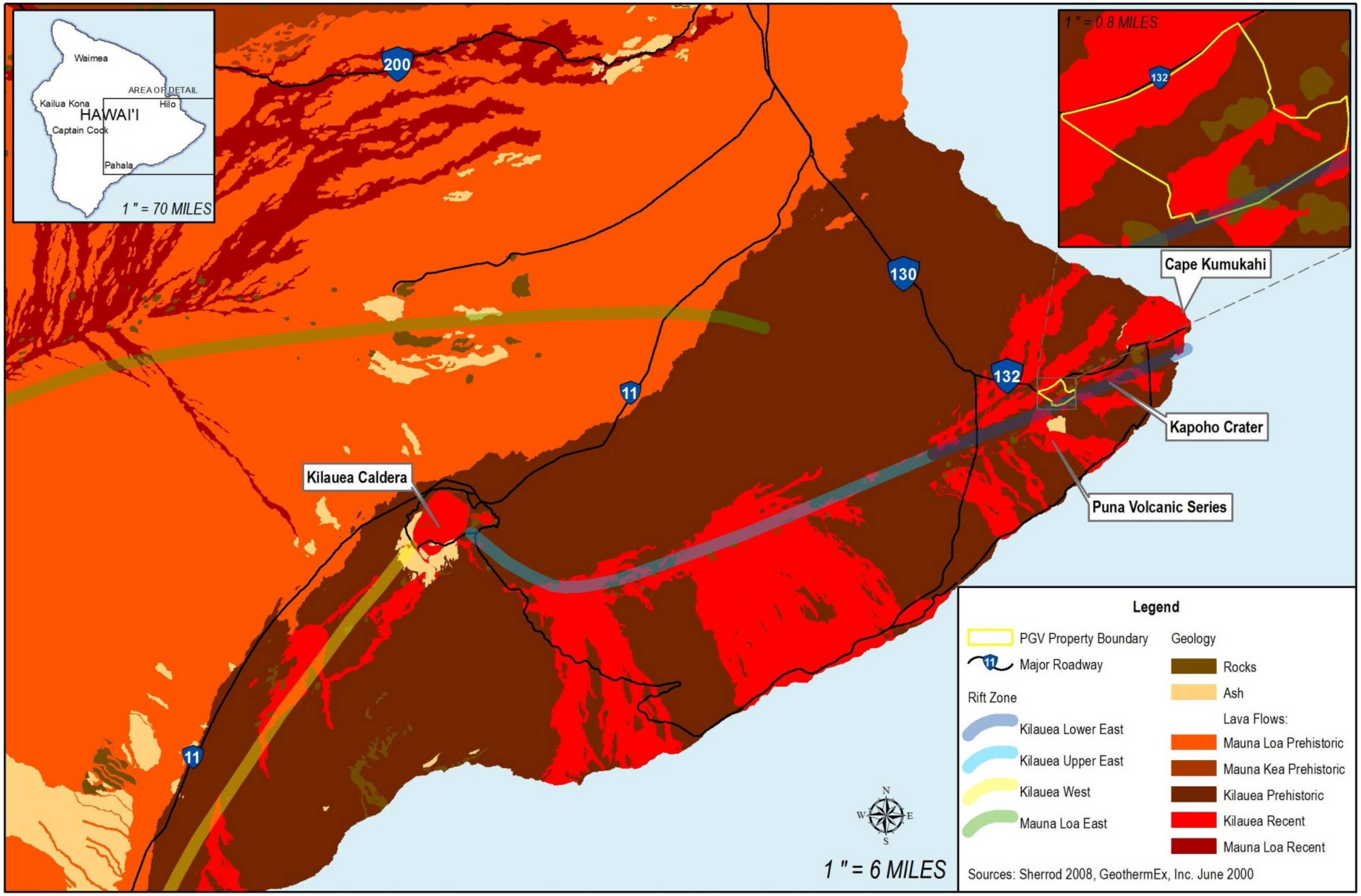
PUNA GEOTHERMAL VENTURE
An ORMAT Company



Cardno

Figure A-2. Map of Kilauea East Rift Zone Showing the Monitoring Well Locations

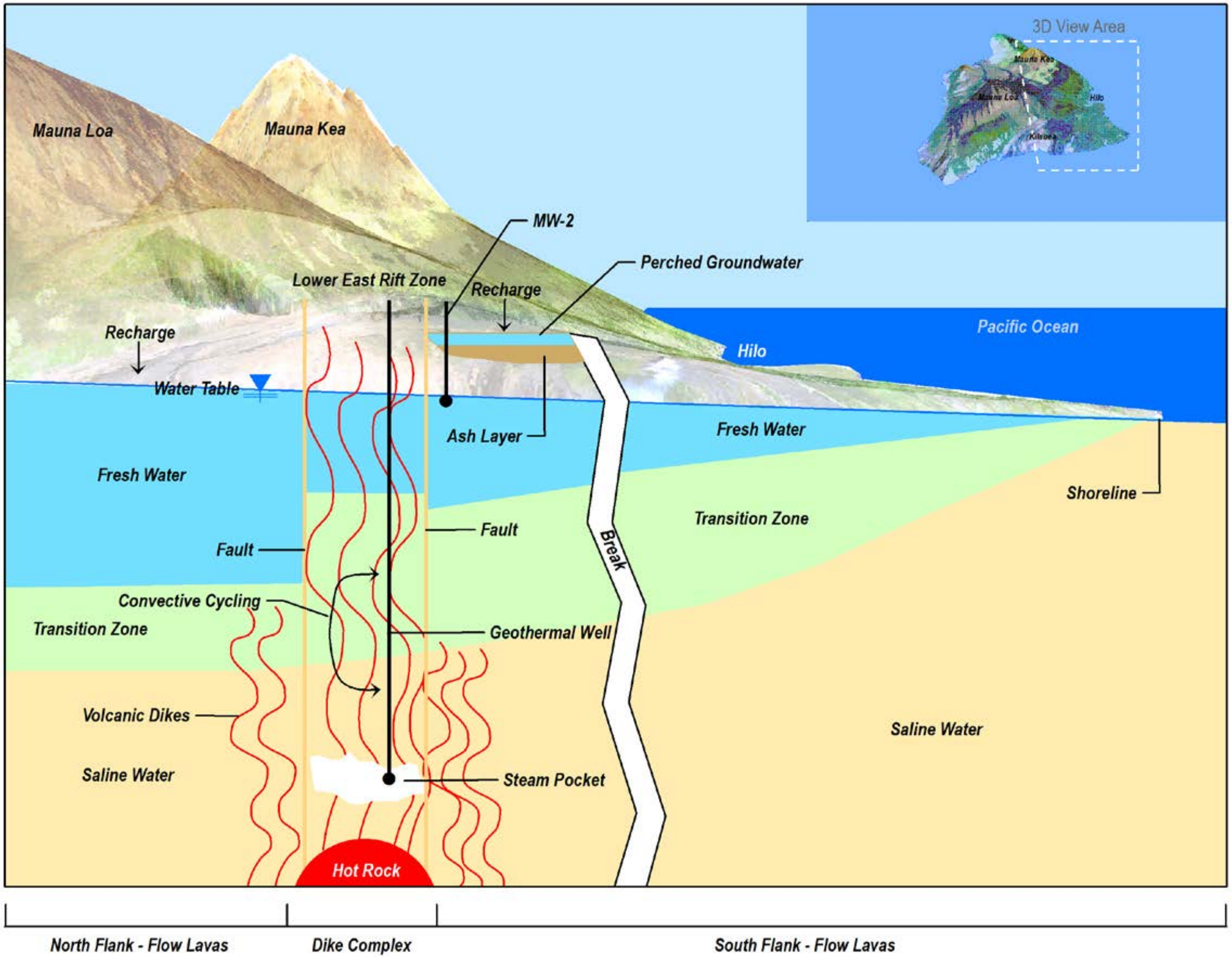
PUNA GEOTHERMAL VENTURE
An ORMAT Company



Cardno

Figure A-3. Geologic Map of East Hawaii

PUNA GEOTHERMAL VENTURE
An ORMAT Company



Cardno

Figure A-4. Generalized Groundwater Diagram of the Geothermal System

PUNA GEOTHERMAL VENTURE
An ORMAT Company

Appendix B

Chain-of-Custody Forms

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Chain of Custody

19F012

Client:
Puna Geothermal Venture
c/o Cardno
64-5266 Puu Nani Dr
Kamuela, HI 96743
Telephone: 808-349-0929
Facsimile: 808-528-0768

Project Manager: Kerry Wells
Field Manager: Kerry Wells
Field Phone: (808)349-0929

Laboratory:
Emax Laboratories
1835 W 205th. St
Torrance, CA 90501
Lab Manager: Raman Singh
Telephone: (310) 618-8889 x119
Facsimile: (310) 618-0818

4/26/2019

Waybill #:

PGV Semi-Annual Groundwater Sampling

	Sample ID	Location	Matrix	Time	Date	Grab		Bromide, Chloride, Fluoride, Sulfate, Nitrate/Nitrite 300 *1L Poly, None*	Total Alkalinity (Carbonate & Bicarbonate) 2320B *1L Poly, None*	Silica 4500-SiO2C *1L Poly, None*	Total Dissolved Solids 2540C *1L Poly, None*	Total Suspended Solids 2540D *1L Poly, None*	Oil & Grease 1664 *1L Amber, HS*	Conductivity 120.1 *1L Poly, None*	Total Sulfur ICPMS, *125 ml amber, None*	Ignitability 1010, *1L Amber, None*	Corrosivity (pH) 150.1 *1L Amber, None*	Reactivity (Cyanide & Sulfide) Chapter 7.3/SW846 *1L Poly, SH/ZA*	TCLPRCRA (8) Metals 1311/6010B/7470A *40 ml VOA, None*	TCLPVolatile Organics 1311/8260B *40 ml VOA, HC*	TCLP Semi-Volatile Organics 1311/8270C *40 ml VOA, None*	Volatile Organics 8260B *40 ml VOA, HC*					
1	190104	MW-04	WG	900	03Jun19	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x					
2	190107	MW-07	WG	1000	03Jun19	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x					
3	190108	Trip Blank		1100	03Jun19																	x					

Carrier: FedEx
Hazard ID: None
Sample Disposal:

TAT:
15 business days

QC Requirements:

Remarks:
Send deliverables to Cardno, Kerry Wells
Send invoice to PGV, Ron Quesada

1.Relinquished By:	1.Date	1.Time	1.Received By:	1.Date	1.Time
[illegible signature]	6/3/19	1100	FedEx	6/3/19	1130
2.Relinquished By:	**2.Date**	**2.Time**	**2.Received By:**	**2.Date**	**2.Time**
			Maria Martinez	6-4-19	9:25
3.Relinquished By:	**3.Date**	**3.Time**	**3.Received By:**	**3.Date**	**3.Time**

same container (1 L Poly, None)
same container (1 L Amber, None)
same container (40 ml VOA, None)
same container (40 ml VOA, HC)
Filtered

Temp: Cooler #1: 5.7°C
#2: 5.4°C

Appendix C

Analytical Laboratory Data Reports

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EMAX
LABORATORIES, INC.
1835 W. 205th Street
Torrance, CA 90501
Tel: (310) 618-8889

Date: 07-02-2019
EMAX Batch No.: 19F012

Attn: Kerry Wells

Puna Geothermal Venture
14-3860 Kapoho-Pahoa Rd.
Pahoa HI 96778

Subject: Laboratory Report
Project: SEMI-ANNUAL GROUNDWATER SAMPLING

Enclosed is the Laboratory report for samples received on 06/04/19.
The data reported relate only to samples listed below :

Sample ID	Control #	Col Date	Matrix	Analysis
190104	F012-01	06/03/19	WATER	IGNITABILITY
				PH
				SULFIDE REACTIVE
				REACTIVE CYANIDE
				METALS TCLP
				MERCURY TCLP
				SEMIVOLATILE ORGANICS TCLP
				VOLATILE ORGANICS TCLP
				VOLATILE ORGANICS BY GC/MS
				SPECIFIC CONDUCTANCE
				ANIONS BY IC
				OIL & GREASE HEM
				TOTAL SULFUR BY ICPMS
				DISSOLVED METALS BY ICP
				DISSOLVED MERCURY
				TOTAL DISSOLVED SOLIDS
				TOTAL SUSPENDED SOLIDS
				ALKALINITY
				SILICA BY SM4500 SIO2C
190107	F012-02	06/03/19	WATER	IGNITABILITY
				PH
				SULFIDE REACTIVE
				REACTIVE CYANIDE
				METALS TCLP
				MERCURY TCLP
				SEMIVOLATILE ORGANICS TCLP
				VOLATILE ORGANICS TCLP
				VOLATILE ORGANICS BY GC/MS
				SPECIFIC CONDUCTANCE
				ANIONS BY IC
				OIL & GREASE HEM
				TOTAL SULFUR BY ICPMS
				DISSOLVED METALS BY ICP
				DISSOLVED MERCURY
				TOTAL DISSOLVED SOLIDS
				TOTAL SUSPENDED SOLIDS
				ALKALINITY
				SILICA BY SM4500 SIO2C

EMAX®
LABORATORIES, INC.
1835 W. 205th Street
Torrance, CA 90501
Tel: (310) 618-8889

Sample ID	Control #	Col Date	Matrix	Analysis
190108	F012-03	06/03/19	WATER	VOLATILE ORGANICS BY GC/MS

Note : TOTAL SULFUR BY ICPMS was subcontracted to Exova.

The results are summarized on the following pages.

Please feel free to call if you have any questions concerning these results.

Sincerely yours,

for [signature]

Caspar J. Pang
Laboratory Director

EMAX certifies that results included in this report meets all TNI & DOD requirements unless noted in the Case Narrative.

NELAP Accredited Certificate Number CA002912018-14
ANAB Accredited DoD ELAP and ISO/IEC 17025 Certificate Number L2278 Testing
California ELAP Accredited Certificate Number 2672

Chain of Custody

19F012

Client:
Puna Geothermal Venture
c/o Cardno
64-5266 Puu Nani Dr
Kamuela, HI 96743
Telephone: 808-349-0929
Facsimile: 808-528-0768

Project Manager: Kerry Wells
Field Manager: Kerry Wells
Field Phone: (808)349-0929

Laboratory:
Emax Laboratories
1835 W 205th. St
Torrance, CA 90501
Lab Manager: Raman Singh
Telephone: (310) 618-8889 x119
Facsimile: (310) 618-0818

4/26/2019

Waybill #:

PGV Semi-Annual Groundwater Sampling

	Sample ID	Location	Matrix	Time	Date	Grab		Bromide, Chloride, Fluoride, Sulfate, Nitrate/Nitrite 300 *1L Poly, None*	Total Alkalinity (Carbonate & Bicarbonate) 2320B *1L Poly, None*	Silica 4500-SiO2C *1L Poly, None*	Total Dissolved Solids 2540C *1L Poly, None*	Total Suspended Solids 2540D *1L Poly, None*	Oil & Grease 1664 *1L Amber, HS*	Conductivity 120.1 *1L Poly, None*	Total Sulfur ICPMS, *125 ml amber, None*	Ignitability 1010, *1L Amber, None*	Corrosivity (pH) 150.1 *1L Amber, None*	Reactivity (Cyanide & Sulfide) Chapter 7.3/SW846 *1L Poly, SH/ZA*	TCLPRCRA (8) Metals 1311/6010B/7470A *40 ml VOA None*	TCLPVolatile Organics 1311/8260B *40 ml VOA, HC*	TCLP Semi-Volatile Organics 1311/8270C *40 ml VOA, None*	Volatile Organics 8260B *40 ml VOA, HC*					
1	190104	MW-04	WG	900	03Jun19	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x					
2	190107	MW-07	WG	1000	03Jun19	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x					
3	190108	Trip Blank		1100	03Jun19																	x					

Carrier: FedEx
Hazard ID: None
Sample Disposal:

TAT:
15 business days

QC Requirements:

Remarks:
Send deliverables to Cardno, Kerry Wells
Send invoice to PGV, Ron Quesada

1.Relinquished By:	1.Date	1.Time	1.Received By:	1.Date	1.Time
[signature]	6/3/19	1100	FedEx	6/3/19	1130
2.Relinquished By:	**2.Date**	**2.Time**	**2.Received By:**	**2.Date**	**2.Time**
			Maria Martinez	6-4-19	9:25
3.Relinquished By:	**3.Date**	**3.Time**	**3.Received By:**	**3.Date**	**3.Time**

same container (1 L Poly, None)
same container (1 L Amber, None)
same container (40 ml VOA, None)
same container (40 ml VOA, HC)
Filtered

Temp: Cooler #1: 5.7°C
#2: 5.4°C

SAMPLE RECEIPT FORM 1

Type of Delivery	Airbill / Tracking Number	ECN 19E012
☑ Fedex ☐ UPS ☐ GSO ☐ Others	7876 5288 1088	Recipient Maria Martinez
☐ EMAX Courier ☐ Client Delivery		Date 6-4-19 Time 9:25

COC INSPECTION

☑ Client Name ☑ Client PM/FC ☐ Sampler Name ☑ Sampling Date/Time ☑ Sample ID ☑ Matrix
☑ Address ☑ Tel # / Fax # ☐ Courier Signature ☑ Analysis Required ☐ Preservative (if any) ☑ TAT
Safety Issues (if any) ☐ High concentrations expected ☐ From Superfund Site ☐ Rad screening required
Note:

PACKAGING INSPECTION

Container ☑ Cooler ☐ Box ☐ Other
Condition ☑ Custody Seal ☐ Intact ☐ Damaged
Packaging ☑ Bubble Pack ☐ Styrofoam ☐ Popcorn ☐ Sufficient ☐
Temperatures (Cool, ≤6 °C but not frozen) ☑ Cooler 1 5.7 °C ☐ Cooler 2 5.4 °C ☐ Cooler 3 ___ °C ☐ Cooler 4 ___ °C ☐ Cooler 5 ___ °C
☐ Cooler 6 ___ °C ☐ Cooler 7 ___ °C ☐ Cooler 8 ___ °C ☐ Cooler 9 ___ °C ☐ Cooler 10 ___ °C
Thermometer: A - S/N 170324872 B - S/N 150555522 C - S/N 170324888 D - S/N ___
Comments: ☐ **Temperature is out of range. PM was informed IMMEDIATELY.**
Note:

DISCREPANCIES

LabSampleID	LabSampleContainerID	Code	ClientSample Label ID / Information	Corrective Action
1	3	D4	~~MVN 6-4-19~~ Just location - MW4	R1 - COC
1, 2	15, 29	D12	~~Anal 7515~~ Recieved 1L amber.	(*) proceed with 1L amber
1, 2	1-29	D10		R1
3	30-35	D22	TB-004-03-10 w/HCl	R1 - COC
1	1-4	D17	COC leads TCLP VOC prep. w/HCl	Use unpres. vials for TCLP VOA
1, 2	1-8, 16-22	D14		inform PM if any issues; R4

6/4/19

☐ pH holding time requirement for water samples is 15 mins. Water samples for pH analysis are received beyond 15 minutes from sampling time.

NOTES/OBSERVATIONS: Reactive Cyanide is requested on the same bottle as reactive sulfide. Analysis on COC asks for total suspended solids 2540D 1L Poly, but ~~did not recieve bottle~~ MVN 6-4-19 analysis is not indicated in label.
(*) TCLP Metals, SVOC, pH, Ignit

LEGEND: ☐ Continue to next page.

Code	Description- Sample Management	Code	Description-Sample Management	Code	Description-Sample Management
D1	Analysis is not indicated in ___	D13	Out of Holding Time	R1	Proceed as indicated in ☐ COC ☐ Label
D2	Analysis mismatch COC vs label	D14	Bubble is >6mm	R2	Refer to attached instruction
D3	Sample ID mismatch COC vs label	D15	No trip blank in cooler	R3	Cancel the analysis
D4	Sample ID is not indicated in label	D16	Preservation not indicated in ___	R4	Use vial with smallest bubble first
D5	Container -[improper] [leaking] [broken]	D17	Preservation mismatch COC vs label	R5	Log-in with latest sampling date and time+1 min
D6	Date/Time is not indicated in ___	D18	Insufficient chemical preservative	R6	Adjust pH as necessary
D7	Date/Time mismatch COC vs label	D19	Insufficient Sample	R7	Filter and preserved as necessary
D8	Sample listed in COC is not received	D20	No filtration info for dissolved analysis	R8	
D9	Sample received is not listed in COC	D21	No sample for moisture determination	R9	
D10	No initial/date on corrections in COC/label	D22	No label	R10	
D11	Container count mismatch COC vs received	D23		R11	
D12	Container size mismatch COC vs received	D24		R12	

REVIEWS:
Sample Labeling Maria Martinez Date 6-4-19 | [signature] 6/4/19 | SRF [signature] Date 6/4/19 | PM [signature] Date 6/4/19

EMAX Laboratories, Inc. 1835 W. 205th St., Torrance, Ca 90501

ORIGIN ID:ITOA (808) 349-0929
KERRY WELLS
CARDNO
64 5249 PAU NANI DR

KAMUELA, HI 96743
UNITED STATES US

SHIP DATE: 03JUN19
ACTWGT: 42.80 LB
CAD: 006994317/SSFE2002
DIMS: 26x14x15 IN

BILL THIRD PARTY

Part # 156297-435 RRDB EXP 05/19

TO **RAMAN SINGH**
EMAX LAB
1835 W 205TH ST

TORRANCE CA 90501
(999) 999-9999 REF:
INV:
PO: DEPT:

FedEx
Express

E

J191019010701uv

2 of 2
MPS# 0263 **7876 5288 1099**
Mstr# 7876 5288 1088 0201

TUE - 04 JUN 10:30A
PRIORITY OVERNIGHT

WZ HHRA

90501
CA-US **LAX**

1 Temp: 5.7°C A

ORIGIN ID:ITOA (808) 349-0525
KERRY WELLS
CARDNO
64 5249 PAU NANI DR

KAMUELA, HI 96743
UNITED STATES US

ACTWGT: 46.20 LB
CAD: 006994317/SSFE2002
DIMS: 26x14x15 IN

BILL THIRD PARTY

TO **RAMAN SINGH**
EMAX LAB
1835 W 205TH ST

TORRANCE CA 90501
(999) 999-9999 REF:
INV:
PO: DEPT:

FedEx
Express

E

J191019010701uv

565J1/D210/23AD

156297-435 RRDB EXP 05/19

1 of 2
TRK# 0201 **7876 5288 1088**
MASTER

TUE - 04 JUN 10:30A
PRIORITY OVERNIGHT

WZ HHRA

90501
CA-US **LAX**

2 Temp: 5.4°C

REPORTING CONVENTIONS

DATA QUALIFIERS:

Lab Qualifier	AFCEE Qualifier	Description
J	F	Indicates that the analyte is positively identified and the result is less than RL but greater than MDL.
N		Indicates presumptive evidence of a compound.
B	B	Indicates that the analyte is found in the associated method blank as well as in the sample at above QC level.
E	J	Indicates that the result is above the maximum calibration range or estimated value.
*	*	Out of QC limit.

Note: The above qualifiers are used to flag the results unless the project requires a different set of qualification criteria.

ACRONYMS AND ABBREVIATIONS:

CRDL	Contract Required Detection Limit
RL	Reporting Limit
MRL	Method Reporting Limit
PQL	Practical Quantitation Limit
MDL	Method Detection Limit
DO	Diluted out

DATES

The date and time information for leaching and preparation reflect the beginning date and time of the procedure unless the method, protocol, or project specifically requires otherwise.

LABORATORY REPORT FOR

PUNA GEOTHERMAL VENTURE

SEMI-ANNUAL GROUNDWATER SAMPLING

METHOD 5030B/8260B
VOLATILE ORGANICS BY GC/MS

SDG#: 19F012

CASE NARRATIVE

Client : PUNA GEOTHERMAL VENTURE

Project: SEMI-ANNUAL GROUNDWATER SAMPLING

SDG : 19F012

METHOD 5030B/8260B
VOLATILE ORGANICS BY GC/MS

A total of three (3) water samples were received on 06/04/19 to be analyzed for Volatile Organics by GC/MS in accordance with Method 5030B/8260B and project specific requirements.

Holding Time
Samples were analyzed within the prescribed holding time.

Instrument Performance and Calibration
Instrument tune check was performed prior to calibration. Result was within acceptance criteria. Multi-calibration points were generated to establish initial calibration (ICAL). ICAL was verified using secondary source (ICV). Continuing calibration (CCV) was carried out at a frequency required by the project. There was one (1) CCV associated with this SDG Target analytes in CCV (Data file ID: RFN076) were within calibration acceptance criteria. All calibration requirements were satisfied. Refer to calibration summary forms of ICAL, ICV and CCV for details.

Method Blank
Method blank was prepared and analyzed at the frequency required by the project. For this SDG, one (1) method blank was analyzed. VWF4F04B - result was compliant to project requirement. Refer to sample result summary form for details.

Lab Control Sample
Lab control sample was prepared and analyzed at a frequency required by the project. For this SDG, one (1) set of LCS/LCD was analyzed. VWF4F04L/VWF4F04C were within LCS limits. Refer to LCS summary form for details.

Matrix QC Sample
No matrix QC sample was provided on this SDG.

Surrogate
Surrogates were added on QC and field samples. All surrogate recoveries were within QC limits. Refer to sample result summary forms for details.

Sample Analysis
Samples were analyzed according to prescribed analytical procedures. Results were evaluated in accordance to project requirements. For this SDG, all quality control requirements were met.
All vials received for sample 19E012-01 and -02 had bubbles >6MM. The vial with the smallest bubble was selected for analysis.

LAB CHRONICLE
VOLATILE ORGANICS BY GC/MS

Client : PUNA GEOTHERMAL VENTURE
Project : SEMI-ANNUAL GROUNDWATER SAMPLING

SDG NO. : 19F012
Instrument ID : F4

WATER

Client Sample ID	Laboratory Sample ID	Dilution Factor	% Moist	Analysis DateTime	Extraction DateTime	Sample Data FN	Calibration Data FN	Prep. Batch	Notes
MBLK1W	VWF4F04B	1	NA	06/11/1915:47	06/11/1915:47	RFN081	RDN139	VWF4F04	Method Blank
LCS1W	VWF4F04L	1	NA	06/11/1914:24	06/11/1914:24	RFN077	RDN139	VWF4F04	Lab Control Sample (LCS)
LCD1W	VWF4F04C	1	NA	06/11/1914:52	06/11/1914:52	RFN078	RDN139	VWF4F04	LCS Duplicate
190104	F012-01	1	NA	06/11/1919:05	06/11/1919:05	RFN088	RDN139	VWF4F04	Field Sample
190107	F012-02	1	NA	06/11/1919:35	06/11/1919:35	RFN089	RDN139	VWF4F04	Field Sample
190108	F012-03	1	NA	06/11/1920:03	06/11/1920:03	RFN090	RDN139	VWF4F04	Field Sample

FN - Filename
% Moist - Percent Moisture

SAMPLE RESULTS

METHOD 5030B/8260B
VOLATILE ORGANICS BY GC/MS

Client	: PUNA GEOTHERMAL VENTURE	Date Collected:	06/03/19
Project	: SEMI-ANNUAL GROUNDWATER SAMPLING	Date Received:	06/04/19
Batch No.	: 19F012	Date Extracted:	06/11/19 19:05
Sample ID:	190104	Date Analyzed:	06/11/19 19:05
Lab Samp ID:	F012-01	Dilution Factor:	1
Lab File ID:	RFN088	Matrix	: WATER
Ext Btch ID:	VWF4F04	% Moisture	: NA
Calib. Ref.:	RDN139	Instrument ID	: TOF4

PARAMETERS	RESULTS (ug/L)	RL (ug/L)	MDL (ug/L)
1,1,1-TRICHLOROETHANE	ND	5.0	1.0
1,1,2,2-TETRACHLOROETHANE	ND	5.0	1.0
1,1,2-TRICHLOROETHANE	ND	5.0	1.0
1,1-DICHLOROETHANE	ND	5.0	1.0
1,1-DICHLOROETHENE	ND	5.0	1.0
1,2-DICHLOROBENZENE	ND	5.0	1.0
1,2-DICHLOROETHANE	ND	5.0	1.0
1,2-DICHLOROPROPANE	ND	5.0	1.0
1,3-DICHLOROBENZENE	ND	5.0	2.0
1,4-DICHLOROBENZENE	ND	5.0	2.0
2-CHLOROETHYL VINYL ETHER	ND	10	4.0
BENZENE	ND	5.0	1.0
BROMODICHLOROMETHANE	ND	5.0	2.0
BROMOFORM	ND	5.0	2.0
BROMOMETHANE	ND	5.0	3.0
CARBON TETRACHLORIDE	ND	5.0	1.0
CHLOROBENZENE	ND	5.0	1.0
CHLOROETHANE	ND	5.0	2.0
CHLOROFORM	ND	5.0	1.0
CHLOROMETHANE	ND	5.0	2.0
CIS-1,3-DICHLOROPROPENE	ND	5.0	1.0
DIBROMOCHLOROMETHANE	ND	5.0	1.0
ETHYLBENZENE	ND	5.0	1.0
METHYLENE CHLORIDE	ND	10	4.0
TETRACHLOROETHENE	ND	5.0	2.0
TOLUENE	ND	5.0	1.0
TRANS-1,2-DICHLOROETHENE	ND	5.0	1.0
TRANS-1,3-DICHLOROPROPENE	ND	5.0	1.0
TRICHLOROETHENE	ND	5.0	1.0
TRICHLOROFLUOROMETHANE	ND	5.0	2.0
VINYL CHLORIDE	ND	6.0	4.0

SURROGATE PARAMETERS	RESULTS	SPK_AMT	% RECOVERY	QC LIMIT
1,2-DICHLOROETHANE-D4	41.2	50.00	82.4	70-140
4-BROMOFLUOROBENZENE	49.9	50.00	99.8	70-130
TOLUENE-D8	52.2	50.00	104	70-140

METHOD 5030B/8260B
VOLATILE ORGANICS BY GC/MS

Client : PUNA GEOTHERMAL VENTURE	Date Collected: 06/03/19
Project : SEMI-ANNUAL GROUNDWATER SAMPLING	Date Received: 06/04/19
Batch No. : 19F012	Date Extracted: 06/11/19 19:35
Sample ID: 190107	Date Analyzed: 06/11/19 19:35
Lab Samp ID: F012-02	Dilution Factor: 1
Lab File ID: RFN089	Matrix : WATER
Ext Btch ID: VWF4F04	% Moisture : NA
Calib. Ref.: RDN139	Instrument ID : TOF4

PARAMETERS	RESULTS (ug/L)	RL (ug/L)	MDL (ug/L)
1,1,1-TRICHLOROETHANE	ND	5.0	1.0
1,1,2,2-TETRACHLOROETHANE	ND	5.0	1.0
1,1,2-TRICHLOROETHANE	ND	5.0	1.0
1,1-DICHLOROETHANE	ND	5.0	1.0
1,1-DICHLOROETHENE	ND	5.0	1.0
1,2-DICHLOROBENZENE	ND	5.0	1.0
1,2-DICHLOROETHANE	ND	5.0	1.0
1,2-DICHLOROPROPANE	ND	5.0	1.0
1,3-DICHLOROBENZENE	ND	5.0	2.0
1,4-DICHLOROBENZENE	ND	5.0	2.0
2-CHLOROETHYL VINYL ETHER	ND	10	4.0
BENZENE	ND	5.0	1.0
BROMODICHLOROMETHANE	ND	5.0	2.0
BROMOFORM	ND	5.0	2.0
BROMOMETHANE	ND	5.0	3.0
CARBON TETRACHLORIDE	ND	5.0	1.0
CHLOROBENZENE	ND	5.0	1.0
CHLOROETHANE	ND	5.0	2.0
CHLOROFORM	ND	5.0	1.0
CHLOROMETHANE	ND	5.0	2.0
CIS-1,3-DICHLOROPROPENE	ND	5.0	1.0
DIBROMOCHLOROMETHANE	ND	5.0	1.0
ETHYLBENZENE	ND	5.0	1.0
METHYLENE CHLORIDE	ND	10	4.0
TETRACHLOROETHENE	ND	5.0	2.0
TOLUENE	ND	5.0	1.0
TRANS-1,2-DICHLOROETHENE	ND	5.0	1.0
TRANS-1,3-DICHLOROPROPENE	ND	5.0	1.0
TRICHLOROETHENE	ND	5.0	1.0
TRICHLOROFLUOROMETHANE	ND	5.0	2.0
VINYL CHLORIDE	ND	6.0	4.0

SURROGATE PARAMETERS	RESULTS	SPK_AMT	% RECOVERY	QC LIMIT
1,2-DICHLOROETHANE-D4	40.4	50.00	80.8	70-140
4-BROMOFLUOROBENZENE	48.5	50.00	97.1	70-130
TOLUENE-D8	51.8	50.00	104	70-140

METHOD 5030B/8260B
VOLATILE ORGANICS BY GC/MS

Client : PUNA GEOTHERMAL VENTURE	Date Collected: 06/03/19
Project : SEMI-ANNUAL GROUNDWATER SAMPLING	Date Received: 06/04/19
Batch No. : 19F012	Date Extracted: 06/11/19 20:03
Sample ID: 190108	Date Analyzed: 06/11/19 20:03
Lab Samp ID: F012-03	Dilution Factor: 1
Lab File ID: RFN090	Matrix : WATER
Ext Btch ID: VWF4F04	% Moisture : NA
Calib. Ref.: RDN139	Instrument ID : TOF4

PARAMETERS	RESULTS (ug/L)	RL (ug/L)	MDL (ug/L)
1,1,1-TRICHLOROETHANE	ND	5.0	1.0
1,1,2,2-TETRACHLOROETHANE	ND	5.0	1.0
1,1,2-TRICHLOROETHANE	ND	5.0	1.0
1,1-DICHLOROETHANE	ND	5.0	1.0
1,1-DICHLOROETHENE	ND	5.0	1.0
1,2-DICHLOROBENZENE	ND	5.0	1.0
1,2-DICHLOROETHANE	ND	5.0	1.0
1,2-DICHLOROPROPANE	ND	5.0	1.0
1,3-DICHLOROBENZENE	ND	5.0	2.0
1,4-DICHLOROBENZENE	ND	5.0	2.0
2-CHLOROETHYL VINYL ETHER	ND	10	4.0
BENZENE	ND	5.0	1.0
BROMODICHLOROMETHANE	ND	5.0	2.0
BROMOFORM	ND	5.0	2.0
BROMOMETHANE	ND	5.0	3.0
CARBON TETRACHLORIDE	ND	5.0	1.0
CHLOROBENZENE	ND	5.0	1.0
CHLOROETHANE	ND	5.0	2.0
CHLOROFORM	ND	5.0	1.0
CHLOROMETHANE	ND	5.0	2.0
CIS-1,3-DICHLOROPROPENE	ND	5.0	1.0
DIBROMOCHLOROMETHANE	ND	5.0	1.0
ETHYLBENZENE	ND	5.0	1.0
METHYLENE CHLORIDE	ND	10	4.0
TETRACHLOROETHENE	ND	5.0	2.0
TOLUENE	ND	5.0	1.0
TRANS-1,2-DICHLOROETHENE	ND	5.0	1.0
TRANS-1,3-DICHLOROPROPENE	ND	5.0	1.0
TRICHLOROETHENE	ND	5.0	1.0
TRICHLOROFLUOROMETHANE	ND	5.0	2.0
VINYL CHLORIDE	ND	6.0	4.0

SURROGATE PARAMETERS	RESULTS	SPK_AMT	% RECOVERY	QC LIMIT
1,2-DICHLOROETHANE-D4	41.6	50.00	83.2	70-140
4-BROMOFLUOROBENZENE	48.9	50.00	97.7	70-130
TOLUENE-D8	51.8	50.00	104	70-140

QC SUMMARIES

METHOD 5030B/8260B
VOLATILE ORGANICS BY GC/MS

Client	: PUNA GEOTHERMAL VENTURE	Date Collected:	NA
Project	: SEMI-ANNUAL GROUNDWATER SAMPLING	Date Received:	06/11/19
Batch No.	: 19F012	Date Extracted:	06/11/19 15:47
Sample ID:	MBLK1W	Date Analyzed:	06/11/19 15:47
Lab Samp ID:	VWF4F04B	Dilution Factor:	1
Lab File ID:	RFN081	Matrix	: WATER
Ext Btch ID:	VWF4F04	% Moisture	: NA
Calib. Ref.:	RDN139	Instrument ID	: TOF4

PARAMETERS	RESULTS (ug/L)	RL (ug/L)	MDL (ug/L)
1,1,1-TRICHLOROETHANE	ND	5.0	1.0
1,1,2,2-TETRACHLOROETHANE	ND	5.0	1.0
1,1,2-TRICHLOROETHANE	ND	5.0	1.0
1,1-DICHLOROETHANE	ND	5.0	1.0
1,1-DICHLOROETHENE	ND	5.0	1.0
1,2-DICHLOROBENZENE	ND	5.0	1.0
1,2-DICHLOROETHANE	ND	5.0	1.0
1,2-DICHLOROPROPANE	ND	5.0	1.0
1,3-DICHLOROBENZENE	ND	5.0	2.0
1,4-DICHLOROBENZENE	ND	5.0	2.0
2-CHLOROETHYL VINYL ETHER	ND	10	4.0
BENZENE	ND	5.0	1.0
BROMODICHLOROMETHANE	ND	5.0	2.0
BROMOFORM	ND	5.0	2.0
BROMOMETHANE	ND	5.0	3.0
CARBON TETRACHLORIDE	ND	5.0	1.0
CHLOROBENZENE	ND	5.0	1.0
CHLOROETHANE	ND	5.0	2.0
CHLOROFORM	ND	5.0	1.0
CHLOROMETHANE	ND	5.0	2.0
CIS-1,3-DICHLOROPROPENE	ND	5.0	1.0
DIBROMOCHLOROMETHANE	ND	5.0	1.0
ETHYLBENZENE	ND	5.0	1.0
METHYLENE CHLORIDE	ND	10	4.0
TETRACHLOROETHENE	ND	5.0	2.0
TOLUENE	ND	5.0	1.0
TRANS-1,2-DICHLOROETHENE	ND	5.0	1.0
TRANS-1,3-DICHLOROPROPENE	ND	5.0	1.0
TRICHLOROETHENE	ND	5.0	1.0
TRICHLOROFLUOROMETHANE	ND	5.0	2.0
VINYL CHLORIDE	ND	6.0	4.0

SURROGATE PARAMETERS	RESULTS	SPK_AMT	% RECOVERY	QC LIMIT
1,2-DICHLOROETHANE-D4	42.4	50.00	84.8	70-140
4-BROMOFLUOROBENZENE	48.3	50.00	96.6	70-130
TOLUENE-D8	51.0	50.00	102	70-130

EMAX QUALITY CONTROL DATA
LCS/LCD ANALYSIS

CLIENT: PUNA GEOTHERMAL VENTURE
PROJECT: SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO.: 19F012
METHOD: METHOD 5030B/8260B

MATRIX:	WATER			% MOISTURE:	NA
DILUTION FACTOR:	1	1	1		
SAMPLE ID:	MBLK1W				
LAB SAMP ID:	VWF4F04B	VWF4F04L	VWF4F04C		
LAB FILE ID:	RFN081	RFN077	RFN078		
DATE EXTRACTED:	06/11/1915:47	06/11/1914:24	06/11/1914:52	DATE COLLECTED:	NA
DATE ANALYZED:	06/11/1915:47	06/11/1914:24	06/11/1914:52	DATE RECEIVED:	06/11/19
PREP. BATCH:	VWF4F04	VWF4F04	VWF4F04		
CALIB. REF:	RDN139	RDN139	RDN139		

ACCESSION:

PARAMETER	BLNK RSLT (ug/L)	SPIKE AMT (ug/L)	BS RSLT (ug/L)	BS % REC	SPIKE AMT (ug/L)	BSD RSLT (ug/L)	BSD % REC	RPD (%)	QC LIMIT (%)	MAX RPD (%)
1,1-Dichloroethene	ND	50.0	46.8	94	50.0	49.3	99	5	60-130	30
Benzene	ND	50.0	47.5	95	50.0	49.5	99	4	70-130	30
Chlorobenzene	ND	50.0	48.8	98	50.0	50.6	101	4	70-130	30
Toluene	ND	50.0	50.3	101	50.0	51.9	104	3	70-130	30
Trichloroethene	ND	50.0	48.5	97	50.0	50.8	102	5	70-130	30

SURROGATE PARAMETER	SPIKE AMT (ug/L)	BS RSLT (ug/L)	BS % REC	SPIKE AMT (ug/L)	BSD RSLT (ug/L)	BSD % REC	QC LIMIT (%)
1,2-Dichloroethane-d4	50.0	40.6	81	50.0	42.0	84	70-140
4-Bromofluorobenzene	50.0	50.7	101	50.0	50.0	100	70-130
Toluene-d8	50.0	51.8	104	50.0	51.0	102	70-130

LABORATORY REPORT FOR

PUNA GEOTHERMAL VENTURE

SEMI-ANNUAL GROUNDWATER SAMPLING

METHOD 1311/5030B/8260B
TCLP VOLATILE ORGANICS BY GC/MS

SDG#: 19F012

CASE NARRATIVE

Client : PUNA GEOTHERMAL VENTURE

Project: SEMI-ANNUAL GROUNDWATER SAMPLING

SDG : 19F012

METHOD 1311/5030B/8260B
TCLP VOLATILE ORGANICS BY GC/MS

A total of two(2) water samples were received on 06/04/19 to be analyzed for TCLP Volatile Organics by GC/MS in accordance with Method 1311/5030B/8260B and project specific requirements.

Holding Time
Samples were analyzed within the prescribed holding time.

Instrument Performance and Calibration
Instrument tune check was performed prior to calibration. Result was within acceptance criteria. Multi-calibration points were generated to establish initial calibration (ICAL). ICAL was verified using secondary source (ICV). Continuing calibration (CCV) was carried out at a frequency required by the project. There was one(1)CCV associated with this SDG Target analytes in CCV(Datafile ID:RFN162) were within calibration acceptance criteria. All calibration requirements were satisfied. Refer to calibration summary forms of ICAL, ICV and CCV for details.

Method Blank
Method blank was prepared and analyzed at the frequency required by the project. For this SDG, two(2) method blanks were analyzed. TVF002WB and VWF4F07B were compliant to project requirement. Refer to sample result summary forms for details.

Lab Control Sample
Lab control sample was prepared and analyzed at a frequency required by the project. For this SDG, one(1) set of LCS/LCD was analyzed. VWF4F07L/VWF4F07C were within LCS limits. Refer to LCS summary form for details.

Matrix QC Sample
Matrix spike sample was prepared and analyzed at a frequency required by the project. For this SDG, one(1) set of MS/MSD was analyzed. F012-02M/F012-02S - all analytes were within MS QC limits. Refer to Matrix QC summary form for details.

Surrogate
Surrogates were added on QC and field samples. All surrogate recoveries were within QC limits. Refer to sample result summary forms for details.

Sample Analysis
Samples were analyzed according to prescribed analytical procedures. Results were evaluated in accordance to project requirements. For this SDG, all quality control requirements were met.

LAB CHRONICLE
TCLP VOLATILE ORGANICS BY GC/MS

Client : PUNA GEOTHERMAL VENTURE
Project : SEMI-ANNUAL GROUNDWATER SAMPLING

SDG NO. : 19F012
Instrument ID : F4

LEACHATE

Client Sample ID	Laboratory Sample ID	Dilution Factor	% Moist	Analysis DateTime	Extraction DateTime	Sample Data FN	Calibration Data FN	Prep. Batch	Notes
MBLK1W	VWF4F07B	1	NA	06/14/1912:43	06/14/1912:43	RFN168	RDN139	VWF4F07	Method Blank
LCS1W	VWF4F07L	1	NA	06/14/1911:19	06/14/1911:19	RFN165	RDN139	VWF4F07	Lab Control Sample (LCS)
LCD1W	VWF4F07C	1	NA	06/14/1911:46	06/14/1911:46	RFN166	RDN139	VWF4F07	LCS Duplicate
MBLK2W	TVF002WB	10	NA	06/14/1916:04	06/14/1916:04	RFN175	RDN139	VWF4F07	Method Blank
190104	F012-01	10	NA	06/14/1916:33	06/14/1916:33	RFN176	RDN139	VWF4F07	Field Sample
190107	F012-02	10	NA	06/14/1917:01	06/14/1917:01	RFN177	RDN139	VWF4F07	Field Sample
190107MS	F012-02M	10	NA	06/14/1917:51	06/14/1917:51	RFN178	RDN139	VWF4F07	Matrix Spike Sample (MS)
190107MSD	F012-02S	10	NA	06/14/1918:19	06/14/1918:19	RFN179	RDN139	VWF4F07	MS Duplicate (MSD)

FN - Filename
% Moist - Percent Moisture

SAMPLE RESULTS

METHOD 1311/5030B/8260B
TCLP VOLATILE ORGANICS BY GC/MS

Client	: PUNA GEOTHERMAL VENTURE	Date Collected:	06/03/19
Project	: SEMI-ANNUAL GROUNDWATER SAMPLING	Date Received:	06/04/19
Batch No.	: 19F012	Date Extracted:	06/14/19 16:33
Sample ID	: 190104	Date Analyzed:	06/14/19 16:33
Lab Samp ID	: F012-01	Dilution Factor:	10
Lab File ID	: RFN176	Matrix	: LEACHATE
Ext Btch ID	: VWF4F07	% Moisture	: NA
Calib. Ref.	: RDN139	Instrument ID	: TOF4

PARAMETERS	RESULTS (ug/L)	RL (ug/L)	MDL (ug/L)
BENZENE	ND	50	10
METHYL ETHYL KETONE	ND	100	50
CARBON TETRACHLORIDE	ND	50	10
CHLOROBENZENE	ND	50	10
CHLOROFORM	ND	50	10
1,4-DICHLOROBENZENE	ND	50	20
1,2-DICHLOROETHANE	ND	50	10
1,1-DICHLOROETHENE	ND	50	10
TETRACHLOROETHENE	ND	50	20
TRICHLOROETHENE	ND	50	10
VINYL CHLORIDE	ND	60	40

SURROGATE PARAMETERS	RESULTS	SPK_AMT	% RECOVERY	QC LIMIT
1,2-DICHLOROETHANE-D4	434	500.0	86.7	70-140
4-BROMOFLUOROBENZENE	490	500.0	98.1	70-130
TOLUENE-D8	512	500.0	102	70-140

DateTime Leached: 06/07/19 15:59

METHOD 1311/5030B/8260B
TCLP VOLATILE ORGANICS BY GC/MS

Client	: PUNA GEOTHERMAL VENTURE	Date Collected:	06/03/19
Project	: SEMI-ANNUAL GROUNDWATER SAMPLING	Date Received:	06/04/19
Batch No.	: 19F012	Date Extracted:	06/14/19 17:01
Sample ID:	190107	Date Analyzed:	06/14/19 17:01
Lab Samp ID:	F012-02	Dilution Factor:	10
Lab File ID:	RFN177	Matrix	: LEACHATE
Ext Btch ID:	VWF4F07	% Moisture	: NA
Calib. Ref.:	RDN139	Instrument ID	: TOF4

PARAMETERS	RESULTS (ug/L)	RL (ug/L)	MDL (ug/L)
BENZENE	ND	50	10
METHYL ETHYL KETONE	ND	100	50
CARBON TETRACHLORIDE	ND	50	10
CHLOROBENZENE	ND	50	10
CHLOROFORM	ND	50	10
1,4-DICHLOROBENZENE	ND	50	20
1,2-DICHLOROETHANE	ND	50	10
1,1-DICHLOROETHENE	ND	50	10
TETRACHLOROETHENE	ND	50	20
TRICHLOROETHENE	ND	50	10
VINYL CHLORIDE	ND	60	40

SURROGATE PARAMETERS	RESULTS	SPK_AMT	% RECOVERY	QC LIMIT
1,2-DICHLOROETHANE-D4	437	500.0	87.4	70-140
4-BROMOFLUOROBENZENE	490	500.0	97.9	70-130
TOLUENE-D8	509	500.0	102	70-140

DateTime Leached: 06/07/19 15:59

QC SUMMARIES

METHOD 1311/5030B/8260B
TCLP VOLATILE ORGANICS BY GC/MS

Client	: PUNA GEOTHERMAL VENTURE	Date Collected:	NA
Project	: SEMI-ANNUAL GROUNDWATER SAMPLING	Date Received:	06/14/19
Batch No.	: 19F012	Date Extracted:	06/14/19 12:43
Sample ID:	MBLK1W	Date Analyzed:	06/14/19 12:43
Lab Samp ID:	VWF4F07B	Dilution Factor:	1
Lab File ID:	RFN168	Matrix	: WATER
Ext Btch ID:	VWF4F07	% Moisture	: NA
Calib. Ref.:	RDN139	Instrument ID	: TOF4

PARAMETERS	RESULTS (ug/L)	RL (ug/L)	MDL (ug/L)
BENZENE	ND	5.0	1.0
METHYL ETHYL KETONE	ND	10	5.0
CARBON TETRACHLORIDE	ND	5.0	1.0
CHLOROBENZENE	ND	5.0	1.0
CHLOROFORM	ND	5.0	1.0
1,4-DICHLOROBENZENE	ND	5.0	2.0
1,2-DICHLOROETHANE	ND	5.0	1.0
1,1-DICHLOROETHENE	ND	5.0	1.0
TETRACHLOROETHENE	ND	5.0	2.0
TRICHLOROETHENE	ND	5.0	1.0
VINYL CHLORIDE	ND	6.0	4.0

SURROGATE PARAMETERS	RESULTS	SPK_AMT	% RECOVERY	QC LIMIT
1,2-DICHLOROETHANE-D4	42.7	50.00	85.4	70-140
4-BROMOFLUOROBENZENE	50.3	50.00	101	70-130
TOLUENE-D8	51.9	50.00	104	70-130

METHOD 1311/5030B/8260B
TCLP VOLATILE ORGANICS BY GC/MS

Client	: PUNA GEOTHERMAL VENTURE	Date Collected:	NA
Project	: SEMI-ANNUAL GROUNDWATER SAMPLING	Date Received:	06/14/19
Batch No.	: 19F012	Date Extracted:	06/14/19 16:04
Sample ID:	MBLK2W	Date Analyzed:	06/14/19 16:04
Lab Samp ID:	TVF002WB	Dilution Factor:	10
Lab File ID:	RFN175	Matrix	: LEACHATE
Ext Btch ID:	VWF4F07	% Moisture	: NA
Calib. Ref.:	RDN139	Instrument ID	: TOF4

PARAMETERS	RESULTS (ug/L)	RL (ug/L)	MDL (ug/L)
BENZENE	ND	50	10
METHYL ETHYL KETONE	ND	100	50
CARBON TETRACHLORIDE	ND	50	10
CHLOROBENZENE	ND	50	10
CHLOROFORM	ND	50	10
1,4-DICHLOROBENZENE	ND	50	20
1,2-DICHLOROETHANE	ND	50	10
1,1-DICHLOROETHENE	ND	50	10
TETRACHLOROETHENE	ND	50	20
TRICHLOROETHENE	ND	50	10
VINYL CHLORIDE	ND	60	40

SURROGATE PARAMETERS	RESULTS	SPK_AMT	% RECOVERY	QC LIMIT
1,2-DICHLOROETHANE-D4	439	500.0	87.9	70-140
4-BROMOFLUOROBENZENE	501	500.0	100	70-130
TOLUENE-D8	501	500.0	100	70-130

DateTime Leached: 06/07/19 15:59

EMAX QUALITY CONTROL DATA
LCS/LCD ANALYSIS

CLIENT: PUNA GEOTHERMAL VENTURE
PROJECT: SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO.: 19F012
METHOD: METHOD 1311/5030B/8260B

MATRIX:	WATER			% MOISTURE:	NA
DILUTION FACTOR:	1	1	1		
SAMPLE ID:	MBLK1W				
LAB SAMP ID:	VWF4F07B	VWF4F07L	VWF4F07C		
LAB FILE ID:	RFN168	RFN165	RFN166		
DATE EXTRACTED:	06/14/1912:43	06/14/1911:19	06/14/1911:46	DATE COLLECTED:	NA
DATE ANALYZED:	06/14/1912:43	06/14/1911:19	06/14/1911:46	DATE RECEIVED:	06/14/19
PREP. BATCH:	VWF4F07	VWF4F07	VWF4F07		
CALIB. REF:	RDN139	RDN139	RDN139		

ACCESSION:

PARAMETER	BLNK RSLT (ug/L)	SPIKE AMT (ug/L)	BS RSLT (ug/L)	BS % REC	SPIKE AMT (ug/L)	BSD RSLT (ug/L)	BSD % REC	RPD (%)	QC LIMIT (%)	MAX RPD (%)
Benzene	ND	50.0	47.7	95	50.0	42.1	84	12	70-130	30
Methyl Ethyl Ketone	ND	250	288	115	250	263	105	9	60-140	30
Carbon Tetrachloride	ND	50.0	46.2	92	50.0	40.5	81	13	70-130	30
Chlorobenzene	ND	50.0	48.6	97	50.0	43.8	88	10	70-130	30
Chloroform	ND	50.0	47.6	95	50.0	43.1	86	10	70-130	30
1,4-Dichlorobenzene	ND	50.0	49.0	98	50.0	43.6	87	12	70-130	30
1,2-Dichloroethane	ND	50.0	44.2	88	50.0	40.8	82	8	70-130	30
1,1-Dichloroethene	ND	50.0	47.3	95	50.0	41.5	83	13	60-130	30
Tetrachloroethene	ND	50.0	51.3	103	50.0	43.6	87	16	70-130	30
Trichloroethene	ND	50.0	49.0	98	50.0	42.8	86	14	70-130	30
Vinyl Chloride	ND	50.0	54.0	108	50.0	50.6	101	6	60-150	30

SURROGATE PARAMETER	SPIKE AMT (ug/L)	BS RSLT (ug/L)	BS % REC	SPIKE AMT (ug/L)	BSD RSLT (ug/L)	BSD % REC	QC LIMIT (%)
1,2-Dichloroethane-d4	50.0	42.0	84	50.0	42.5	85	70-140
4-Bromofluorobenzene	50.0	50.9	102	50.0	50.7	101	70-130
Toluene-d8	50.0	51.5	103	50.0	51.6	103	70-130

EMAX QUALITY CONTROL DATA
MS/MSD ANALYSIS

CLIENT: PUNA GEOTHERMAL VENTURE
PROJECT: SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO.: 19F012
METHOD: METHOD 1311/5030B/8260B

MATRIX:	LEACHATE			% MOISTURE:	NA
DILUTION FACTOR:	10	10	10		
SAMPLE ID:	190107				
LAB SAMP ID:	F012-02	F012-02M	F012-02S		
LAB FILE ID:	RFN177	RFN178	RFN179		
DATE EXTRACTED:	06/14/1917:01	06/14/1917:51	06/14/1918:19	DATE COLLECTED:	06/03/19
DATE ANALYZED:	06/14/1917:01	06/14/1917:51	06/14/1918:19	DATE RECEIVED:	06/04/19
PREP. BATCH:	VWF4F07	VWF4F07	VWF4F07		
CALIB. REF:	RDN139	RDN139	RDN139		

ACCESSION:

PARAMETER	SMPL RSLT (ug/L)	SPIKE AMT (ug/L)	MS RSLT (ug/L)	MS % REC	SPIKE AMT (ug/L)	MSD RSLT (ug/L)	MSD % REC	RPD (%)	QC LIMIT (%)	MAX RPD (%)
Benzene	ND	500	430	86	500	426	85	1	60-140	30
Methyl Ethyl Ketone	ND	2500	2460	98	2500	2670	107	8	60-150	30
Carbon Tetrachloride	ND	500	423	85	500	417	83	2	60-140	30
Chlorobenzene	ND	500	446	89	500	439	88	2	70-130	30
Chloroform	ND	500	447	89	500	441	88	1	70-130	30
1,4-Dichlorobenzene	ND	500	451	90	500	431	86	4	70-130	30
1,2-Dichloroethane	ND	500	428	86	500	420	84	2	70-140	30
1,1-Dichloroethene	ND	500	429	86	500	430	86	0	60-140	30
Tetrachloroethene	ND	500	452	90	500	450	90	0	70-130	30
Trichloroethene	ND	500	436	87	500	435	87	0	60-140	30
Vinyl Chloride	ND	500	429	86	500	460	92	7	60-160	30

SURROGATE PARAMETER	SPIKE AMT (ug/L)	MS RSLT (ug/L)	MS % REC	SPIKE AMT (ug/L)	MSD RSLT (ug/L)	MSD % REC	QC LIMIT (%)
1,2-Dichloroethane-d4	500	438	88	500	437	87	70-140
4-Bromofluorobenzene	500	502	100	500	500	100	70-130
Toluene-d8	500	516	103	500	515	103	70-140

DateTime Leached: 06/07/19 15:59

LABORATORY REPORT FOR

PUNA GEOTHERMAL VENTURE

SEMI-ANNUAL GROUNDWATER SAMPLING

METHOD 1311/3520C/8270C
TCLP SEMI VOLATILE ORGANICS BY GC/MS

SDG#: 19F012

CASE NARRATIVE

Client : PUNA GEOTHERMAL VENTURE

Project: SEMI-ANNUAL GROUNDWATER SAMPLING

SDG : 19F012

SW 1311/3520C/8270C
TCLP SEMI VOLATILE ORGANICS BY GC/MS

A total of two(2) water samples were received on 06/04/19 to be analyzed for TCLP Semi Volatile Organics by GC/MS in accordance with SW 1311/3520C/8270C and project specific requirements.

Holding Time
Samples were analyzed within the prescribed holding time.

Instrument Performance and Calibration
Instrument tune check was performed prior to calibration. Instrument mass ratios as well as DDT breakdown were evaluated. Results were within acceptance criteria. Tailing factor for Benzidine and Pentachlorophenol were also verified and results were within the method limits. Multi-calibration points were generated to establish initial calibration (ICAL). ICAL was verified using secondary source (ICV). Continuing calibration (CCV) was carried out at a frequency required by the project. There was one(1)CCV associated with this SDG Target analytes in CCV(Datafile ID:RFJ237) were within calibration acceptance criteria. All calibration requirements were satisfied. Refer to calibration summary forms of ICAL, ICV and CCV for details.

Method Blank
Method blank was prepared and analyzed at the frequency required by the project. For this SDG, two(2) method blanks were analyzed. SVF014WB and TXF002WB were compliant to project requirement. Refer to sample result summary forms for details.

Lab Control Sample
Lab control sample was prepared and analyzed at a frequency required by the project. For this SDG, one(1) set of LCS/LCD was analyzed. SVF014WL/SVF014WC were within LCS limits. Refer to LCS summary form for details.

Matrix QC Sample
No matrix QC sample was provided on this SDG.

Surrogate
Surrogates were added on QC and field samples. All surrogate recoveries were within QC limits. Refer to sample result summary forms for details.

Sample Analysis
Samples were analyzed according to prescribed analytical procedures. Results were evaluated in accordance to project requirements. For this SDG, all quality control requirements were met.

LAB CHRONICLE
TCLP SEMI VOLATILE ORGANICS BY GC/MS

Client : PUNA GEOTHERMAL VENTURE
Project : SEMI-ANNUAL GROUNDWATER SAMPLING

SDG NO. : 19F012
Instrument ID : E4

LEACHATE

Client Sample ID	Laboratory Sample ID	Dilution Factor	% Moist	Analysis DateTime	Extraction DateTime	Sample Data FN	Calibration Data FN	Prep. Batch	Notes
MBLK1W	SVF014WB	1	NA	06/13/1909:51	06/10/1913:00	RFJ240	RBJ080	19SVF014W	Method Blank
LCS1W	SVF014WL	1	NA	06/13/1910:10	06/10/1913:00	RFJ241	RBJ080	19SVF014W	Lab Control Sample (LCS)
LCD1W	SVF014WC	1	NA	06/13/1910:29	06/10/1913:00	RFJ242	RBJ080	19SVF014W	LCS Duplicate
LCHBLK1W	TXF002WB	1	NA	06/13/1911:25	06/10/1913:00	RFJ245	RBJ080	19SVF014W	Method Blank
190104	19F012-01	1	NA	06/13/1911:44	06/10/1913:00	RFJ246	RBJ080	19SVF014W	Field Sample
190107	19F012-02	1	NA	06/13/1912:03	06/10/1913:00	RFJ247	RBJ080	19SVF014W	Field Sample

FN - Filename
% Moist - Percent Moisture

SAMPLE RESULTS

SW 1311/3520C/8270C
TCLP SEMI VOLATILE ORGANICS BY GC/MS

Client	: PUNA GEOTHERMAL VENTURE	Date Collected:	06/03/19 09:00
Project	: SEMI-ANNUAL GROUNDWATER SAMPLING		
		Date Received:	06/04/19
Batch No.	: 19F012	Date Extracted:	06/10/19 13:00
Sample ID	: 190104	Date Analyzed:	06/13/19 11:44
Lab Samp ID:	19F012-01	Dilution Factor:	1
Lab File ID:	RFJ246	Matrix:	LEACHATE
Ext Btch ID:	19SVF014W	% Moisture:	NA
Calib. Ref.:	RBJ080	Instrument ID:	E4

PARAMETERS	RESULTS (ug/L)	RL (ug/L)	MDL (ug/L)
2,4,5-Trichlorophenol	ND	100	50
2,4,6-Trichlorophenol	ND	100	50
2,4-Dinitrotoluene	ND	100	50
o-Cresol	ND	100	50
p-Cresol	ND	100	50
Hexachlorobenzene	ND	100	50
Hexachloro-1,3-butadiene	ND	100	50
Hexachloroethane	ND	100	50
Nitrobenzene	ND	100	50
Pyridine	ND	400	200

SURROGATE PARAMETERS	RESULT	SPK_AMT	%RECOVERY	QC LIMIT
2,4,6-Tribromophenol	484	600	81	30-150
2-Fluorobiphenyl	191	200	95	30-130
2-Fluorophenol	340	600	57	20-130
Nitrobenzene-d5	172	200	86	30-130
Phenol-d5	409	600	68	30-130
Terphenyl-d14	180	200	90	30-130

Notes:
(1): Cannot be separated from m-Cresol

Detection limits are reported relative to sample result significant figures.
Sample Amount : 100ml Final Volume : 2ml
Prepared by : JMuert Analyzed by : KVu
DateTime Leached: 06/07/19 12:55

SW 1311/3520C/8270C
TCLP SEMI VOLATILE ORGANICS BY GC/MS

Client	: PUNA GEOTHERMAL VENTURE	Date Collected:	06/03/19 10:00
Project	: SEMI-ANNUAL GROUNDWATER SAMPLING		
		Date Received:	06/04/19
Batch No.	: 19F012	Date Extracted:	06/10/19 13:00
Sample ID	: 190107	Date Analyzed:	06/13/19 12:03
Lab Samp ID:	19F012-02	Dilution Factor:	1
Lab File ID:	RFJ247	Matrix:	LEACHATE
Ext Btch ID:	19SVF014W	% Moisture:	NA
Calib. Ref.:	RBJ080	Instrument ID:	E4

PARAMETERS	RESULTS (ug/L)	RL (ug/L)	MDL (ug/L)
2,4,5-Trichlorophenol	ND	100	50
2,4,6-Trichlorophenol	ND	100	50
2,4-Dinitrotoluene	ND	100	50
o-Cresol	ND	100	50
p-Cresol	ND	100	50
Hexachlorobenzene	ND	100	50
Hexachloro-1,3-butadiene	ND	100	50
Hexachloroethane	ND	100	50
Nitrobenzene	ND	100	50
Pyridine	ND	400	200

SURROGATE PARAMETERS	RESULT	SPK_AMT	%RECOVERY	QC LIMIT
2,4,6-Tribromophenol	525	600	87	30-150
2-Fluorobiphenyl	201	200	101	30-130
2-Fluorophenol	307	600	51	20-130
Nitrobenzene-d5	173	200	87	30-130
Phenol-d5	405	600	68	30-130
Terphenyl-d14	191	200	96	30-130

Notes:
(1): Cannot be separated from m-Cresol

Detection limits are reported relative to sample result significant figures.
Sample Amount : 100ml Final Volume : 2ml
Prepared by : JMuert Analyzed by : KVu
DateTime Leached: 06/07/19 12:55

QC SUMMARIES

SW 1311/3520C/8270C
TCLP SEMI VOLATILE ORGANICS BY GC/MS

Client	: PUNA GEOTHERMAL VENTURE	Date Collected:	06/10/19 13:00
Project	: SEMI-ANNUAL GROUNDWATER SAMPLING		
		Date Received:	06/10/19
Batch No.	: 19F012	Date Extracted:	06/10/19 13:00
Sample ID	: MBLK1W	Date Analyzed:	06/13/19 09:51
Lab Samp ID:	SVF014WB	Dilution Factor:	1
Lab File ID:	RFJ240	Matrix:	WATER
Ext Btch ID:	19SVF014W	% Moisture:	NA
Calib. Ref.:	RBJ080	Instrument ID:	E4

PARAMETERS	RESULTS (ug/L)	RL (ug/L)	MDL (ug/L)
2,4,5-Trichlorophenol	ND	10	5.0
2,4,6-Trichlorophenol	ND	10	5.0
2,4-Dinitrotoluene	ND	10	5.0
o-Cresol	ND	10	5.0
p-Cresol	ND	10	5.0
Hexachlorobenzene	ND	10	5.0
Hexachloro-1,3-butadiene	ND	10	5.0
Hexachloroethane	ND	10	5.0
Nitrobenzene	ND	10	5.0
Pyridine	ND	40	20

SURROGATE PARAMETERS	RESULT	SPK_AMT	%RECOVERY	QC LIMIT
2,4,6-Tribromophenol	52.5	60.0	87	30-150
2-Fluorobiphenyl	20.0	20.0	100	30-130
2-Fluorophenol	30.8	60.0	51	20-130
Nitrobenzene-d5	18.0	20.0	90	30-130
Phenol-d5	42.4	60.0	71	30-130
Terphenyl-d14	18.5	20.0	93	30-130

Notes:
(1): Cannot be separated from m-Cresol

Detection limits are reported relative to sample result significant figures.
Sample Amount : 1000ml Final Volume : 2ml
Prepared by : JMuert Analyzed by : KVu

EMAX QUALITY CONTROL DATA
LAB CONTROL SAMPLE ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO. : 19F012
METHOD : /3520C/8270C

	MB	LCS	LCD
MATRIX	WATER		% MOISTURE:NA
DILUTION FACTOR	1	1	1
SAMPLE ID	MBLK1W	LCS1W	LCD1W
LAB SAMPLE ID	SVF014WB	SVF014WL	SVF014WC
LAB FILE ID	RFJ240	RFJ241	RFJ242
DATE PREPARED	06/10/19 13:00	06/10/19 13:00	06/10/19 13:00
DATE ANALYZED	06/13/19 09:51	06/13/19 10:10	06/13/19 10:29
PREP BATCH	19SVF014W	19SVF014W	19SVF014W
CALIBRATION REF	RBJ080	RBJ080	RBJ080

ACCESSION:

PARAMETERS	MBResult (ug/L)	SpikeAmt (ug/L)	LCSResult (ug/L)	LCSRec (%)	SpikeAmt (ug/L)	LCDResult (ug/L)	LCDRec (%)	RPD (%)	QCLimit (%)	MaxRPD (%)
2,4,5-Trichlorophenol	ND	40.0	33.9	85	40.0	32.7	82	4	40-130	30
2,4,6-Trichlorophenol	ND	40.0	32.9	82	40.0	34.0	85	3	40-130	30
2,4-Dinitrotoluene	ND	40.0	40.4	101	40.0	38.8	97	4	40-130	30
o-Cresol	ND	40.0	27.8	70	40.0	27.1	68	3	30-130	30
p-Cresol	ND	40.0	28.9	72	40.0	29.2	73	1	30-130	30
Hexachlorobenzene	ND	40.0	35.7	89	40.0	35.6	89	0	50-130	30
Hexachloro-1,3-butadiene	ND	40.0	33.1	83	40.0	31.6	79	5	20-130	30
Hexachloroethane	ND	40.0	34.3	86	40.0	32.3	81	6	20-130	30
Nitrobenzene	ND	40.0	34.2	86	40.0	32.4	81	5	30-130	30
Pyridine	ND	80.0	54.7	68	80.0	52.7	66	4	10-130	30

SURROGATE PARAMETERS	SpikeAmt (ug/L)	LCSResult (ug/L)	LCSRec (%)	SpikeAmt (ug/L)	LCDResult (ug/L)	LCDRec (%)	QCLimit (%)
2,4,6-Tribromophenol	60.0	57.5	96	60.0	57.8	96	40-140
2-Fluorobiphenyl	20.0	18.9	95	20.0	18.3	92	40-130
2-Fluorophenol	60.0	26.0	43	60.0	30.2	50	30-130
Nitrobenzene-d5	20.0	17.7	89	20.0	17.6	88	40-130
Phenol-d5	60.0	37.9	63	60.0	40.3	67	30-130
Terphenyl-d14	20.0	18.6	93	20.0	18.9	95	50-130

MB: Method Blank sample LCS: Lab Control Sample LCD: Lab Control Sample Duplicate

SW 1311/3520C/8270C
TCLP SEMI VOLATILE ORGANICS BY GC/MS

Client	: PUNA GEOTHERMAL VENTURE	Date Collected:	06/07/19 12:55
Project	: SEMI-ANNUAL GROUNDWATER SAMPLING		
		Date Received:	06/07/19
Batch No.	: 19F012	Date Extracted:	06/10/19 13:00
Sample ID	: LCHBLK1W	Date Analyzed:	06/13/19 11:25
Lab Samp ID:	TXF002WB	Dilution Factor:	1
Lab File ID:	RFJ245	Matrix:	LEACHATE
Ext Btch ID:	19SVF014W	% Moisture:	NA
Calib. Ref.:	RBJ080	Instrument ID:	E4

PARAMETERS	RESULTS (ug/L)	RL (ug/L)	MDL (ug/L)
2,4,5-Trichlorophenol	ND	100	50
2,4,6-Trichlorophenol	ND	100	50
2,4-Dinitrotoluene	ND	100	50
o-Cresol	ND	100	50
p-Cresol	ND	100	50
Hexachlorobenzene	ND	100	50
Hexachloro-1,3-butadiene	ND	100	50
Hexachloroethane	ND	100	50
Nitrobenzene	ND	100	50
Pyridine	ND	400	200

SURROGATE PARAMETERS	RESULT	SPK_AMT	%RECOVERY	QC LIMIT
2,4,6-Tribromophenol	496	600	83	30-150
2-Fluorobiphenyl	177	200	89	30-130
2-Fluorophenol	297	600	49	20-130
Nitrobenzene-d5	175	200	88	30-130
Phenol-d5	391	600	65	30-130
Terphenyl-d14	190	200	95	30-130

Notes:
(1): Cannot be separated from m-Cresol

Detection limits are reported relative to sample result significant figures.
Sample Amount : 100ml   Final Volume : 2ml
Prepared by : JMuert   Analyzed by : KVu
DateTime Leached: 06/07/19 12:55

LABORATORY REPORT FOR

PUNA GEOTHERMAL VENTURE

SEMI-ANNUAL GROUNDWATER SAMPLING

METHOD 1664
OIL & GREASE

SDG#: 19F012

CASE NARRATIVE

Client : PUNA GEOTHERMAL VENTURE

Project: SEMI-ANNUAL GROUNDWATER SAMPLING

SDG : 19F012

METHOD 1664
OIL & GREASE

A total of two(2) water samples were received on 06/04/19 to be analyzed for Oil & Grease in accordance with Method 1664 and project specific requirements.

Holding Time
Samples were analyzed within the prescribed holding time.

Calibration
Balance calibration verifications were carried out on a frequency specified by the method. All calibration requirements were within acceptance criteria.

Method Blank
Method blank was prepared and analyzed at the frequency required by the project. For this SDG, one(1) method blank was analyzed. Oil & Grease was not detected in OGF005WB. Refer to sample result summary form for details.

Lab Control Sample
Lab control sample was prepared and analyzed at a frequency required by the project. For this SDG, one(1) set of LCS/LCD was analyzed. OGF005WL/OGF005WC were within LCS limits. Refer to LCS summary form for details.

Sample Analysis
Samples were analyzed according to prescribed analytical procedures. Results were evaluated in accordance to project requirements. For this SDG, all quality control requirements were met.

METHOD 1664
Oil & Grease

Client : PUNA GEOTHERMAL VENTURE
Project : SEMI-ANNUAL GROUNDWATER SAMPLING
Batch No. : 19F012

Matrix : WATER
InstrumentID : 402426

CLIENT SAMPLE ID	EMAX SAMPLE ID	RESULTS (mg/L)	PREP FACTOR	MOIST (%)	RL (mg/L)	MDL (mg/L)	ANALYSIS DATETIME	PREPARATION DATETIME	DATA FILE ID	CAL REF	PREP BATCH	COLLECTION DATETIME	RECEIVED DATETIME
MBLK1W	OGF005WB	ND	1.00	NA	5	1.4	06/12/1910:14	06/11/1911:50	19OGF005W02	19OGF005	OGF005W	NA	NA
LCS1W	OGF005WL	38.1	1.00	NA	5	1.4	06/12/1910:14	06/11/1911:50	19OGF005W03	19OGF005	OGF005W	NA	NA
LCD1W	OGF005WC	37.5	1.00	NA	5	1.4	06/12/1910:15	06/11/1911:50	19OGF005W04	19OGF005	OGF005W	NA	NA
190104	F012-01	ND	0.952	NA	4.76	1.33	06/12/1910:16	06/11/1911:50	19OGF005W05	19OGF005	OGF005W	06/03/1909:00	06/04/19
190107	F012-02	ND	0.952	NA	4.76	1.33	06/12/1910:16	06/11/1911:50	19OGF005W06	19OGF005	OGF005W	06/03/1910:00	06/04/19

EMAX QUALITY CONTROL DATA
LAB CONTROL SAMPLE ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO. : 19F012
METHOD : METHOD 1664

===

MATRIX	: WATER		% MOISTURE: NA
DILUTION FACTOR:	1	1	1
SAMPLE ID	: MBLK1W	LCS1W	LCD1W
LAB SAMPLE ID	: OGF005WB	OGF005WL	OGF005WC
LAB FILE ID	: 19OGF005W02	19OGF005W03	19OGF005W04
DATE EXTRACTED	: 06/11/1911:50	06/11/1911:50	06/11/1911:50
DATE ANALYZED	: 06/12/1910:14	06/12/1910:14	06/12/1910:15
PREP BATCH	: OGF005W	OGF005W	OGF005W
CALIBRATION REF:	19OGF005	19OGF005	19OGF005

ACCESSION:

PARAMETER	MB RESULT (mg/L)	SPIKE AMT (mg/L)	BS RESULT (mg/L)	BS REC (%)	SPIKE AMT (mg/L)	BSD RESULT (mg/L)	BSD REC (%)	RPD (%)	QC LIMIT (%)	MAX RPD (%)
OIL & GREASE	ND	40	38.1	95	40	37.5	94	2	78-114	11

LABORATORY REPORT FOR

PUNA GEOTHERMAL VENTURE

SEMI-ANNUAL GROUNDWATER SAMPLING

METALS / MERCURY

SDG#: 19F012

CASE NARRATIVE

Client : PUNA GEOTHERMAL VENTURE

Project: SEMI-ANNUAL GROUNDWATER SAMPLING

SDG : 19F012

METHOD 3010A/6010B (DISSOLVED)
DISSOLVED METALS BY TRACE ICP

A total of two(2) water samples were received on 06/04/19 to be analyzed for Dissolved Metals by Trace ICP in accordance with Method 3010A/6010B (DISSOLVED) and project specific requirements.

Holding Time
Samples were digested and analyzed within the prescribed holding time.

Calibration
Initial Calibration was established as prescribed by the method and was verified using a secondary source(ICV). Interference checks were performed and results were within required limits. Continuing calibration verifications and continuing calibration blanks were carried out at the frequency specified by the project. All calibration requirements were satisfied.

Method Blank
Method blank was prepared and analyzed at the frequency required by the project. For this SDG, one(1) method blank was analyzed. IPF009WB - result was compliant to project requirement. Refer to sample result summary form for details.

Lab Control Sample
Lab control sample was prepared and analyzed at a frequency required by the project. For this SDG, one(1) set of LCS/LCD was analyzed. IPF009WL/IPF009WC were within LCS limits. Refer to LCS summary form for details.

Matrix QC Sample
No matrix QC sample was provided on this SDG.

Sample Analysis
Samples were analyzed according to prescribed analytical procedures. Results were evaluated in accordance to project requirements. For this SDG, all quality control requirements were met.

LAB CHRONICLE
DISSOLVED METALS BY TRACE ICP

Client : PUNA GEOTHERMAL VENTURE
Project : SEMI-ANNUAL GROUNDWATER SAMPLING

SDG NO. : 19F012
Instrument ID : D8

WATER

Client Sample ID	Laboratory Sample ID	Dilution Factor	% Moist	Analysis DateTime	Extraction DateTime	Sample Data FN	Calibration Data FN	Prep. Batch	Notes
MBLK1W	IPF009WB	1.000	NA	06/11/1913:35	06/10/1910:02	ID8F008026	ID8F008024	IPF009W	Method Blank
LCS1W	IPF009WL	1.000	NA	06/11/1913:40	06/10/1910:02	ID8F008027	ID8F008024	IPF009W	Lab Control Sample (LCS)
LCD1W	IPF009WC	1.000	NA	06/11/1913:44	06/10/1910:02	ID8F008028	ID8F008024	IPF009W	LCS Duplicate
190104	F012-01	1.000	NA	06/11/1914:33	06/10/1910:02	ID8F008039	ID8F008036	IPF009W	Field Sample
190107	F012-02	1.000	NA	06/11/1914:38	06/10/1910:02	ID8F008040	ID8F008036	IPF009W	Field Sample
190104	F012-01I	5.000	NA	06/11/1915:55	06/10/1910:02	ID8F008056	ID8F008048	IPF009W	Diluted Sample
190107	F012-02I	5.000	NA	06/11/1915:59	06/10/1910:02	ID8F008057	ID8F008048	IPF009W	Diluted Sample

FN - Filename
% Moist - Percent Moisture

METHOD 3010A/6010B (DISSOLVED)
DISSOLVED METALS BY TRACE ICP

Client	: PUNA GEOTHERMAL VENTURE	Date Collected:	06/03/19 09:00
Project	: SEMI-ANNUAL GROUNDWATER SAMPLING	Date Received:	06/04/19
SDG NO.	: 19F012	Date Extracted:	06/10/19 10:02
Sample ID:	190104	Date Analyzed:	06/11/19 14:33
Lab Samp ID:	F012-01	Dilution Factor:	1
Lab File ID:	ID8F008039	Matrix:	WATER
Ext Btch ID:	IPF009W	% Moisture:	NA
Calib. Ref.:	ID8F008036	Instrument ID:	D8

PARAMETERS	Result (mg/L)	RL (mg/L)	MDL (mg/L)
Arsenic	ND	0.0400	0.0200
Barium	0.0988	0.0100	0.00200
Boron	0.758	0.100	0.0200
Cadmium	ND	0.0100	0.00500
Calcium	94.8	1.00	0.300
Chromium	ND	0.0100	0.00200
Copper	0.00804J	0.0100	0.00300
Iron	0.275	0.200	0.0500
Lead	0.0325	0.0100	0.00500
Magnesium	59.8	0.500	0.100
Manganese	0.277	0.0100	0.00300
Nickel	ND	0.0100	0.00200
Potassium	104	1.00	0.400
Silver	ND	0.00500	0.00100
Vanadium	0.00441J	0.0100	0.00200
Zinc	0.584	0.0500	0.0200
Lithium	0.181J	0.500	0.100

Sample ID:	190104	Date Analyzed:	06/11/19 15:55
Lab Samp ID:	F012-01I	Dilution Factor:	5
Lab File ID:	ID8F008056	Matrix:	WATER
Ext Btch ID:	IPF009W	% Moisture:	NA
Calib. Ref.:	ID8F008048	Instrument ID:	D8

PARAMETERS	Result (mg/L)	RL (mg/L)	MDL (mg/L)
Sodium	1170	5.00	2.50

Note: Detection limits are reported relative to sample result significant figures.
Sample Amount : 50ml   Final Volume:50ml

METHOD 3010A/6010B (DISSOLVED)
DISSOLVED METALS BY TRACE ICP

Client	: PUNA GEOTHERMAL VENTURE	Date Collected:	06/03/19 10:00
Project	: SEMI-ANNUAL GROUNDWATER SAMPLING	Date Received:	06/04/19
SDG NO.	: 19F012	Date Extracted:	06/10/19 10:02
Sample ID:	190107	Date Analyzed:	06/11/19 14:38
Lab Samp ID:	F012-02	Dilution Factor:	1
Lab File ID:	ID8F008040	Matrix:	WATER
Ext Btch ID:	IPF009W	% Moisture:	NA
Calib. Ref.:	ID8F008036	Instrument ID:	D8

PARAMETERS	Result (mg/L)	RL (mg/L)	MDL (mg/L)
Arsenic	ND	0.0400	0.0200
Barium	0.0970	0.0100	0.00200
Boron	0.745	0.100	0.0200
Cadmium	ND	0.0100	0.00500
Calcium	93.8	1.00	0.300
Chromium	ND	0.0100	0.00200
Copper	0.00684J	0.0100	0.00300
Iron	0.266	0.200	0.0500
Lead	0.0347	0.0100	0.00500
Magnesium	59.4	0.500	0.100
Manganese	0.276	0.0100	0.00300
Nickel	ND	0.0100	0.00200
Potassium	103	1.00	0.400
Silver	ND	0.00500	0.00100
Vanadium	0.00456J	0.0100	0.00200
Zinc	0.592	0.0500	0.0200
Lithium	0.179J	0.500	0.100

Sample ID:	190107	Date Analyzed:	06/11/19 15:59
Lab Samp ID:	F012-02I	Dilution Factor:	5
Lab File ID:	ID8F008057	Matrix:	WATER
Ext Btch ID:	IPF009W	% Moisture:	NA
Calib. Ref.:	ID8F008048	Instrument ID:	D8

PARAMETERS	Result (mg/L)	RL (mg/L)	MDL (mg/L)
Sodium	1160	5.00	2.50

Note: Detection limits are reported relative to sample result significant figures.

Sample Amount : 50ml   Final Volume:50ml

METHOD 3010A/6010B (DISSOLVED)
DISSOLVED METALS BY TRACE ICP

Client	: PUNA GEOTHERMAL VENTURE	Date Collected:	NA
Project	: SEMI-ANNUAL GROUNDWATER SAMPLING	Date Received:	NA
SDG NO.	: 19F012	Date Extracted:	06/10/19 10:02
Sample ID:	MBLK1W	Date Analyzed:	06/11/19 13:35
Lab Samp ID:	IPF009WB	Dilution Factor:	1
Lab File ID:	ID8F008026	Matrix:	WATER
Ext Btch ID:	IPF009W	% Moisture:	NA
Calib. Ref.:	ID8F008024	Instrument ID:	D8

PARAMETERS	Result (mg/L)	RL (mg/L)	MDL (mg/L)
Arsenic	ND	0.0400	0.0200
Barium	ND	0.0100	0.00200
Boron	ND	0.100	0.0200
Cadmium	ND	0.0100	0.00500
Calcium	ND	1.00	0.300
Chromium	ND	0.0100	0.00200
Copper	ND	0.0100	0.00300
Iron	ND	0.200	0.0500
Lead	ND	0.0100	0.00500
Magnesium	ND	0.500	0.100
Manganese	ND	0.0100	0.00300
Nickel	ND	0.0100	0.00200
Potassium	ND	1.00	0.400
Silver	ND	0.00500	0.00100
Sodium	ND	1.00	0.500
Vanadium	ND	0.0100	0.00200
Zinc	ND	0.0500	0.0200
Lithium	ND	0.500	0.100

Note: Detection limits are reported relative to sample result significant figures.

Sample Amount : 50ml — Final Volume:50ml

Prepared by : MCande — Analyzed by:NTan

EMAX QUALITY CONTROL DATA
LAB CONTROL SAMPLE ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO. : 19F012
METHOD : 3010A/6010B (DISSOLVED)

MATRIX	: WATER		% MOISTURE:NA
DILUTION FACTOR:	1.000	1.000	1.000
SAMPLE ID	: MBLK1W	LCS1W	LCD1W
LAB SAMPLE ID	: IPF009WB	IPF009WL	IPF009WC
LAB FILE ID	: ID8F008026	ID8F008027	ID8F008028
DATE PREPARED	: 06/10/19 10:02	06/10/19 10:02	06/10/19 10:02
DATE ANALYZED	: 06/11/19 13:35	06/11/19 13:40	06/11/19 13:44
PREP BATCH	: IPF009W	IPF009W	IPF009W
CALIBRATION REF:	ID8F008024	ID8F008024	ID8F008024

ACCESSION:

PARAMETERS	MBResult (mg/L)	SpikeAmt (mg/L)	LCSResult (mg/L)	LCSRec (%)	SpikeAmt (mg/L)	LCDResult (mg/L)	LCDRec (%)	RPD (%)	QCLimit (%)	MaxRPD (%)
Arsenic	ND	0.5	0.532	106	0.5	0.524	105	2	80-120	20
Barium	ND	0.5	0.533	107	0.5	0.523	105	2	80-120	20
Boron	ND	0.5	0.516	103	0.5	0.512	102	1	80-120	20
Cadmium	ND	0.5	0.517	103	0.5	0.512	102	1	80-120	20
Calcium	ND	50	51.0	102	50	50.2	100	2	80-120	20
Chromium	ND	0.5	0.519	104	0.5	0.509	102	2	80-120	20
Copper	ND	0.5	0.503	101	0.5	0.495	99	2	80-120	20
Iron	ND	5	5.34	107	5	5.29	106	1	80-120	20
Lead	ND	0.5	0.519	104	0.5	0.511	102	2	80-120	20
Magnesium	ND	50	48.7	97	50	48.0	96	1	80-120	20
Manganese	ND	0.5	0.517	103	0.5	0.510	102	1	80-120	20
Nickel	ND	0.5	0.523	105	0.5	0.512	102	2	80-120	20
Potassium	ND	50	52.7	105	50	51.9	104	2	80-120	20
Silver	ND	0.5	0.512	102	0.5	0.507	101	1	80-120	20
Sodium	ND	50	54.2	108	50	53.0	106	2	80-120	20
Vanadium	ND	0.5	0.536	107	0.5	0.531	106	1	80-120	20
Zinc	ND	0.5	0.553	111	0.5	0.543	109	2	80-120	20
Lithium	ND	0.5	0.527	105	0.5	0.523	105	1	80-120	20

CASE NARRATIVE

Client : PUNA GEOTHERMAL VENTURE

Project: SEMI-ANNUAL GROUNDWATER SAMPLING

SDG : 19F012

METHOD 1311/3010A/6010B
TCLP METALS BY ICP

A total of two(2) water samples were received on 06/04/19 to be analyzed for TCLP Metals by ICP in accordance with Method 1311/3010A/6010B and project specific requirements.

Holding Time
Samples were digested and analyzed within the prescribed holding time.

Calibration
Initial Calibration was established as prescribed by the method and was verified using a secondary source(ICV). Interference checks were performed and results were within required limits. Continuing calibration verifications and continuing calibration blanks were carried out at the frequency specified by the project. All calibration requirements were satisfied.

Method Blank
Method blank was prepared and analyzed at the frequency required by the project. For this SDG, two(2) method blanks were analyzed. IPF009WB and TXF002WB were compliant to project requirement. Refer to sample result summary forms for details.

Lab Control Sample
Lab control sample was prepared and analyzed at a frequency required by the project. For this SDG, one(1) set of LCS/LCD was analyzed. IPF009WL/IPF009WC were within LCS limits. Refer to LCS summary form for details.

Matrix QC Sample
Matrix spike sample was prepared and analyzed at a frequency required by the project. For this SDG, one(1) set of MS/MSD was analyzed. F012-01M/F012-01S - all analytes were within MS QC limits. Refer to Matrix QC summary form for details.

Sample Analysis
Samples were analyzed according to prescribed analytical procedures. Results were evaluated in accordance to project requirements. For this SDG, all quality control requirements were met.

LAB CHRONICLE
TCLP METALS BY ICP

Client	: PUNA GEOTHERMAL VENTURE	SDG NO.	: 19F012
Project	: SEMI-ANNUAL GROUNDWATER SAMPLING	Instrument ID	: D8

LEACHATE

Client Sample ID	Laboratory Sample ID	Dilution Factor	% Moist	Analysis DateTime	Extraction DateTime	Sample Data FN	Calibration Data FN	Prep. Batch	Notes
MBLK1W	IPF009WB	1.000	NA	06/11/1913:35	06/10/1910:02	ID8F008026	ID8F008024	IPF009W	Method Blank
LCS1W	IPF009WL	1.000	NA	06/11/1913:40	06/10/1910:02	ID8F008027	ID8F008024	IPF009W	Lab Control Sample (LCS)
LCD1W	IPF009WC	1.000	NA	06/11/1913:44	06/10/1910:02	ID8F008028	ID8F008024	IPF009W	LCS Duplicate
MBLK2W	TXF002WB	1.000	NA	06/11/1913:49	06/10/1910:02	ID8F008029	ID8F008024	IPF009W	Method Blank
190104	F012-01	1.000	NA	06/11/1913:58	06/10/1910:02	ID8F008031	ID8F008024	IPF009W	Field Sample
190104MS	F012-01M	1.000	NA	06/11/1914:07	06/10/1910:02	ID8F008033	ID8F008024	IPF009W	Matrix Spike Sample (MS)
190104MSD	F012-01S	1.000	NA	06/11/1914:11	06/10/1910:02	ID8F008034	ID8F008024	IPF009W	MS Duplicate (MSD)
190107	F012-02	1.000	NA	06/11/1914:15	06/10/1910:02	ID8F008035	ID8F008024	IPF009W	Field Sample

FN - Filename
% Moist - Percent Moisture

METHOD 1311/3010A/6010B
TCLP METALS BY ICP

Client	: PUNA GEOTHERMAL VENTURE	Date Collected:	06/03/19 09:00
Project	: SEMI-ANNUAL GROUNDWATER SAMPLING	Date Received:	06/04/19
SDG NO.	: 19F012	Date Extracted:	06/10/19 10:02
Sample ID:	190104	Date Analyzed:	06/11/19 13:58
Lab Samp ID:	F012-01	Dilution Factor:	1
Lab File ID:	ID8F008031	Matrix:	LEACHATE
Ext Btch ID:	IPF009W	% Moisture:	NA
Calib. Ref.:	ID8F008024	Instrument ID:	D8

PARAMETERS	Result (mg/L)	RL (mg/L)	MDL (mg/L)
Arsenic	ND	0.0400	0.0200
Barium	0.0202	0.0100	0.00200
Cadmium	ND	0.0100	0.00500
Chromium	ND	0.0100	0.00200
Lead	0.00673J	0.0100	0.00300
Selenium	ND	0.0200	0.0100
Silver	ND	0.00500	0.00100

Note: Detection limits are reported relative to sample result significant figures.

Sample Amount : 50ml   Final Volume:50ml

Prepared by : MCande   Analyzed by:NTan

DateTime Leached: 06/07/19 12:55

METHOD 1311/3010A/6010B
TCLP METALS BY ICP

Client : PUNA GEOTHERMAL VENTURE	Date Collected: 06/03/19 10:00
Project : SEMI-ANNUAL GROUNDWATER SAMPLING	Date Received: 06/04/19
SDG NO. : 19F012	Date Extracted: 06/10/19 10:02
Sample ID: 190107	Date Analyzed: 06/11/19 14:15
Lab Samp ID: F012-02	Dilution Factor: 1
Lab File ID: ID8F008035	Matrix: LEACHATE
Ext Btch ID: IPF009W	% Moisture: NA
Calib. Ref.: ID8F008024	Instrument ID: D8

PARAMETERS	Result (mg/L)	RL (mg/L)	MDL (mg/L)
Arsenic	ND	0.0400	0.0200
Barium	0.0199	0.0100	0.00200
Cadmium	ND	0.0100	0.00500
Chromium	ND	0.0100	0.00200
Lead	0.00706J	0.0100	0.00300
Selenium	ND	0.0200	0.0100
Silver	ND	0.00500	0.00100

Note: Detection limits are reported relative to sample result significant figures.

Sample Amount : 50ml — Final Volume:50ml

Prepared by : MCande — Analyzed by:NTan

DateTime Leached: 06/07/19 12:55

METHOD 1311/3010A/6010B
TCLP METALS BY ICP

Client	: PUNA GEOTHERMAL VENTURE	Date Collected:	NA
Project	: SEMI-ANNUAL GROUNDWATER SAMPLING	Date Received:	NA
SDG NO.	: 19F012	Date Extracted:	06/10/19 10:02
Sample ID:	MBLK1W	Date Analyzed:	06/11/19 13:35
Lab Samp ID:	IPF009WB	Dilution Factor:	1
Lab File ID:	ID8F008026	Matrix:	WATER
Ext Btch ID:	IPF009W	% Moisture:	NA
Calib. Ref.:	ID8F008024	Instrument ID:	D8

PARAMETERS	Result (mg/L)	RL (mg/L)	MDL (mg/L)
Arsenic	ND	0.0400	0.0200
Barium	ND	0.0100	0.00200
Cadmium	ND	0.0100	0.00500
Chromium	ND	0.0100	0.00200
Lead	ND	0.0100	0.00300
Selenium	ND	0.0200	0.0100
Silver	ND	0.00500	0.00100

Note: Detection limits are reported relative to sample result significant figures.
Sample Amount : 50ml Final Volume:50ml
Prepared by : MCande Analyzed by:NTan

EMAX QUALITY CONTROL DATA
LAB CONTROL SAMPLE ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO. : 19F012
METHOD : 1311/3010A/6010B

MATRIX	: WATER		% MOISTURE:NA
DILUTION FACTOR:	1.000	1.000	1.000
SAMPLE ID	: MBLK1W	LCS1W	LCD1W
LAB SAMPLE ID	: IPF009WB	IPF009WL	IPF009WC
LAB FILE ID	: ID8F008026	ID8F008027	ID8F008028
DATE PREPARED	: 06/10/19 10:02	06/10/19 10:02	06/10/19 10:02
DATE ANALYZED	: 06/11/19 13:35	06/11/19 13:40	06/11/19 13:44
PREP BATCH	: IPF009W	IPF009W	IPF009W
CALIBRATION REF:	ID8F008024	ID8F008024	ID8F008024

ACCESSION:

PARAMETERS	MBResult (mg/L)	SpikeAmt (mg/L)	LCSResult (mg/L)	LCSRec (%)	SpikeAmt (mg/L)	LCDResult (mg/L)	LCDRec (%)	RPD (%)	QCLimit (%)	MaxRPD (%)
Arsenic	ND	0.5	0.532	106	0.5	0.524	105	2	80-120	20
Barium	ND	0.5	0.533	107	0.5	0.523	105	2	80-120	20
Cadmium	ND	0.5	0.517	103	0.5	0.512	102	1	80-120	20
Chromium	ND	0.5	0.519	104	0.5	0.509	102	2	80-120	20
Lead	ND	0.5	0.519	104	0.5	0.511	102	2	80-120	20
Selenium	ND	0.5	0.537	107	0.5	0.528	106	2	80-120	20
Silver	ND	0.5	0.512	102	0.5	0.507	101	1	80-120	20

METHOD 1311/3010A/6010B
TCLP METALS BY ICP

Client	: PUNA GEOTHERMAL VENTURE	Date Collected:	NA
Project	: SEMI-ANNUAL GROUNDWATER SAMPLING	Date Received:	NA
SDG NO.	: 19F012	Date Extracted:	06/10/19 10:02
Sample ID:	MBLK2W	Date Analyzed:	06/11/19 13:49
Lab Samp ID:	TXF002WB	Dilution Factor:	1
Lab File ID:	ID8F008029	Matrix:	LEACHATE
Ext Btch ID:	IPF009W	% Moisture:	NA
Calib. Ref.:	ID8F008024	Instrument ID:	D8

PARAMETERS	Result (mg/L)	RL (mg/L)	MDL (mg/L)
Arsenic	ND	0.200	0.100
Barium	ND	0.0500	0.0100
Cadmium	ND	0.0500	0.0250
Chromium	ND	0.0500	0.0100
Lead	ND	0.0500	0.0150
Selenium	ND	0.100	0.0500
Silver	ND	0.0250	0.00500

Note: Detection limits are reported relative to sample result significant figures.
Sample Amount : 10ml Final Volume:50ml
Prepared by : MCande Analyzed by:NTan
DateTime Leached: 06/07/19 12:55

EMAX QUALITY CONTROL DATA
MS/MSD ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO. : 19F012
METHOD : 1311/3010A/6010B

===

MATRIX	: LEACHATE		% MOISTURE: NA
DILUTION FACTOR	: 1	1	1
SAMPLE ID	: 190104	190104MS	190104MSD
LAB SAMPLE ID	: F012-01	F012-01M	F012-01S
LAB FILE ID	: ID8F008031	ID8F008033	ID8F008034
DATE PREPARED	: 06/10/19 10:02	06/10/19 10:02	06/10/19 10:02
DATE ANALYZED	: 06/11/19 13:58	06/11/19 14:07	06/11/19 14:11
PREP BATCH	: IPF009W	IPF009W	IPF009W
CALIBRATION REF	: ID8F008024	ID8F008024	ID8F008024

ACCESSION:

PARAMETERS	PSResult (mg/L)	SpikeAmt (mg/L)	MSResult (mg/L)	MSRec (%)	SpikeAmt (mg/L)	MSDResult (mg/L)	MSDRec (%)	RPD (%)	QCLimit (%)	MaxRPD (%)
Arsenic	ND	2.5	2.45	98.0	2.5	2.51	100	2	75-125	20
Barium	0.0202	2.5	2.44	96.8	2.5	2.50	99.2	2	75-125	20
Cadmium	ND	2.5	2.32	92.8	2.5	2.37	94.8	2	75-125	20
Chromium	ND	2.5	2.25	90.0	2.5	2.36	94.4	5	75-125	20
Lead	0.00673J	2.5	2.28	90.9	2.5	2.38	94.9	4	75-125	20
Selenium	ND	2.5	2.44	97.6	2.5	2.49	99.6	2	75-125	20
Silver	ND	2.5	2.27	90.8	2.5	2.32	92.8	2	75-125	20

===

PSResult - Parent Sample Result

CASE NARRATIVE

Client : PUNA GEOTHERMAL VENTURE

Project: SEMI-ANNUAL GROUNDWATER SAMPLING

SDG : 19F012

METHOD 7470A (DISSOLVED)
DISSOLVED MERCURY BY COLD VAPOR

A total of two(2) water samples were received on 06/04/19 to be analyzed for Dissolved Mercury by Cold Vapor in accordance with Method 7470A (DISSOLVED) and project specific requirements.

Holding Time
Samples were digested and analyzed within the prescribed holding time.

Calibration
Multi-calibration points were generated to establish initial calibration (ICAL). ICAL was verified using a secondary source (ICV). Continuing calibration (CCV) verifications were carried out on a frequency specified by the project. All calibration requirements were within acceptance criteria.

Method Blank
Method blank was prepared and analyzed at the frequency required by the project. For this SDG, one(1) method blank was analyzed. Mercury was not detected in HGF006WB. Refer to sample result summary form for details.

Lab Control Sample
Lab control sample was prepared and analyzed at a frequency required by the project. For this SDG, one(1) set of LCS/LCD was analyzed. HGF006WL/HGF006WC were within LCS limits. Refer to LCS summary form for details.

Matrix QC Sample
No matrix QC sample was provided on this SDG.

Sample Analysis
Samples were analyzed according to prescribed analytical procedures. Results were evaluated in accordance to project requirements. For this SDG, all quality control requirements were met.

LAB CHRONICLE
DISSOLVED MERCURY BY COLD VAPOR

Client	: PUNA GEOTHERMAL VENTURE	SDG NO.	: 19F012
Project	: SEMI-ANNUAL GROUNDWATER SAMPLING	Instrument ID	: 47

WATER

Client Sample ID	Laboratory Sample ID	Dilution Factor	% Moist	Analysis DateTime	Extraction DateTime	Sample Data FN	Calibration Data FN	Prep. Batch	Notes
MBLK1W	HGF006WB	1	NA	06/06/1916:00	06/06/1911:45	M47F004012	M47F004	19HGF006W	Method Blank
LCS1W	HGF006WL	1	NA	06/06/1916:02	06/06/1911:45	M47F004013	M47F004	19HGF006W	Lab Control Sample (LCS)
LCD1W	HGF006WC	1	NA	06/06/1916:04	06/06/1911:45	M47F004014	M47F004	19HGF006W	LCS Duplicate
190104	F012-01	1	NA	06/06/1916:35	06/06/1911:45	M47F004028	M47F004	19HGF006W	Field Sample
190107	F012-02	1	NA	06/06/1916:37	06/06/1911:45	M47F004029	M47F004	19HGF006W	Field Sample

FN - Filename
% Moist - Percent Moisture

METHOD 7470A (DISSOLVED)
DISSOLVED MERCURY BY COLD VAPOR

Client : PUNA GEOTHERMAL VENTURE
Project : SEMI-ANNUAL GROUNDWATER SAMPLING
Batch No. : 19F012

Matrix : WATER
InstrumentID : 47

CLIENT SAMPLE ID	EMAX SAMPLE ID	RESULTS (ug/L)	DILT'N FACTOR	MOIST (%)	RL (ug/L)	MDL (ug/L)	ANALYSIS DATETIME	PREPARATION DATETIME	DATA FILE ID	CAL REF	PREP BATCH	COLLECTION DATETIME	RECEIVED DATETIME
MBLK1W	HGF006WB	ND	1	NA	0.500	0.200	06/06/1916:00	06/06/1911:45	M47F004012	M47F004	19HGF006W	NA	NA
LCS1W	HGF006WL	2.72	1	NA	0.500	0.200	06/06/1916:02	06/06/1911:45	M47F004013	M47F004	19HGF006W	NA	NA
LCD1W	HGF006WC	2.67	1	NA	0.500	0.200	06/06/1916:04	06/06/1911:45	M47F004014	M47F004	19HGF006W	NA	NA
190104	F012-01	ND	1	NA	0.500	0.200	06/06/1916:35	06/06/1911:45	M47F004028	M47F004	19HGF006W	06/03/1909:00	06/04/19
190107	F012-02	ND	1	NA	0.500	0.200	06/06/1916:37	06/06/1911:45	M47F004029	M47F004	19HGF006W	06/03/1910:00	06/04/19

Note: Detection limits are reported relative to sample result significant figures.

EMAX QUALITY CONTROL DATA
LAB CONTROL SAMPLE ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO. : 19F012
METHOD : METHOD 7470A (DISSOLVED)

MATRIX	: WATER		% MOISTURE:NA
DILUTION FACTOR:	1	1	1
SAMPLE ID	: MBLK1W	LCS1W	LCD1W
LAB SAMPLE ID	: HGF006WB	HGF006WL	HGF006WC
LAB FILE ID	: M47F004012	M47F004013	M47F004014
DATE PREPARED	: 06/06/1911:45	06/06/1911:45	06/06/1911:45
DATE ANALYZED	: 06/06/1916:00	06/06/1916:02	06/06/1916:04
PREP BATCH	: 19HGF006W	19HGF006W	19HGF006W
CALIBRATION REF:	M47F004	M47F004	M47F004

ACCESSION:

PARAMETERS	MBResult (ug/L)	SpikeAmt (ug/L)	LCSResult (ug/L)	LCSRec (%)	SpikeAmt (ug/L)	LCDResult (ug/L)	LCDRec (%)	RPD (%)	QCLimit (%)	MaxRPD (%)
Mercury	ND	2.50	2.72	109	2.50	2.67	107	2	80-120	20

MB: Method Blank sample LCS: Lab Control Sample LCD: Lab Control Sample Duplicate

CASE NARRATIVE

Client : PUNA GEOTHERMAL VENTURE

Project: SEMI-ANNUAL GROUNDWATER SAMPLING

SDG : 19F012

METHOD 1311/7470A
TCLP MERCURY

A total of two(2) water samples were received on 06/04/19 to be analyzed for Tclp Mercury in accordance with Method 1311/7470A and project specific requirements.

Holding Time
Samples were digested and analyzed within the prescribed holding time.

Calibration
Multi-calibration points were generated to establish initial calibration (ICAL). ICAL was verified using a secondary source (ICV). Continuing calibration (CCV) verifications were carried out on a frequency specified by the project. All calibration requirements were within acceptance criteria.

Method Blank
Method blank was prepared and analyzed at the frequency required by the project. For this SDG, two(2) method blanks were analyzed. HGF009WB and TXF002WB were compliant to project requirement. Refer to sample result summary forms for details.

Lab Control Sample
Lab control sample was prepared and analyzed at a frequency required by the project. For this SDG, one(1) set of LCS/LCD was analyzed. HGF009WL/HGF009WC were within LCS limits. Refer to LCS summary form for details.

Matrix QC Sample
Matrix spike sample was prepared and analyzed at a frequency required by the project. For this SDG, one(1) set of MS/MSD was analyzed. Mercury was within MS QC limits in F012-01M/F012-01S. Refer to Matrix QC summary form for details.

Sample Analysis
Samples were analyzed according to prescribed analytical procedures. Results were evaluated in accordance to project requirements. For this SDG, all quality control requirements were met.

LAB CHRONICLE
TCLP MERCURY

Client : PUNA GEOTHERMAL VENTURE
Project : SEMI-ANNUAL GROUNDWATER SAMPLING

SDG NO. : 19F012
Instrument ID : 47

WATER

Client Sample ID	Laboratory Sample ID	Dilution Factor	% Moist	Analysis DateTime	Extraction DateTime	Sample Data FN	Calibration Data FN	Prep. Batch	Notes
MBLK1W	HGF009WB	1	NA	06/10/1916:08	06/10/1912:28	M47F006012	M47F006	19HGF009W	Method Blank
LCS1W	HGF009WL	1	NA	06/10/1916:11	06/10/1912:28	M47F006013	M47F006	19HGF009W	Lab Control Sample (LCS)
LCD1W	HGF009WC	1	NA	06/10/1916:13	06/10/1912:28	M47F006014	M47F006	19HGF009W	LCS Duplicate
MBLK2W	TXF002WB	1	NA	06/10/1917:10	06/10/1912:28	M47F006040	M47F006	19HGF009W	Method Blank
190104	F012-01	1	NA	06/10/1917:15	06/10/1912:28	M47F006042	M47F006	19HGF009W	Field Sample
190104MS	F012-01M	1	NA	06/10/1917:19	06/10/1912:28	M47F006044	M47F006	19HGF009W	Matrix Spike Sample (MS)
190104MSD	F012-01S	1	NA	06/10/1917:43	06/10/1912:28	M47F006047	M47F006	19HGF009W	MS Duplicate (MSD)
190107	F012-02	1	NA	06/10/1917:46	06/10/1912:28	M47F006048	M47F006	19HGF009W	Field Sample

FN - Filename
% Moist - Percent Moisture

METHOD 1311/7470A
TCLP MERCURY

Client	: PUNA GEOTHERMAL VENTURE	Matrix	: LEACHATE
Project	: SEMI-ANNUAL GROUNDWATER SAMPLING	InstrumentID	: 47
Batch No.	: 19F012		

CLIENT SAMPLE ID	EMAX SAMPLE ID	RESULTS (ug/L)	DILT'N FACTOR	MOIST (%)	RL (ug/L)	MDL (ug/L)	ANALYSIS DATETIME	PREPARATION DATETIME	DATA FILE ID	CAL REF	PREP BATCH	COLLECTION DATETIME	RECEIVED DATETIME
MBLK1W	HGF009WB	ND	1	NA	0.500	0.200	06/10/1916:08	06/10/1912:28	M47F006012	M47F006	19HGF009W	NA	NA
LCS1W	HGF009WL	2.59	1	NA	0.500	0.200	06/10/1916:11	06/10/1912:28	M47F006013	M47F006	19HGF009W	NA	NA
LCD1W	HGF009WC	2.53	1	NA	0.500	0.200	06/10/1916:13	06/10/1912:28	M47F006014	M47F006	19HGF009W	NA	NA
MBLK2W	TXF002WB	ND	1	NA	5.00	2.00	06/10/1917:10	06/10/1912:28	M47F006040	M47F006	19HGF009W	NA	NA
190104	F012-01	ND	1	NA	5.00	2.00	06/10/1917:15	06/10/1912:28	M47F006042	M47F006	19HGF009W	06/03/1909:00	06/04/19
190104MS	F012-01M	25.9	1	NA	5.00	2.00	06/10/1917:19	06/10/1912:28	M47F006044	M47F006	19HGF009W	06/03/1909:00	06/04/19
190104MSD	F012-01S	26.1	1	NA	5.00	2.00	06/10/1917:43	06/10/1912:28	M47F006047	M47F006	19HGF009W	06/03/1909:00	06/04/19
190107	F012-02	ND	1	NA	5.00	2.00	06/10/1917:46	06/10/1912:28	M47F006048	M47F006	19HGF009W	06/03/1910:00	06/04/19

Note: Detection limits are reported relative to sample result significant figures.

DateTime Leached: 06/07/2019 12:55
Note: 5 ml leachate was diluted to 50 ml reagent water prior to digestion.

EMAX QUALITY CONTROL DATA
LAB CONTROL SAMPLE ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO. : 19F012
METHOD : METHOD 1311/7470A

MATRIX	: WATER		% MOISTURE:NA
DILUTION FACTOR:	1	1	1
SAMPLE ID	: MBLK1W	LCS1W	LCD1W
LAB SAMPLE ID	: HGF009WB	HGF009WL	HGF009WC
LAB FILE ID	: M47F006012	M47F006013	M47F006014
DATE PREPARED	: 06/10/1912:28	06/10/1912:28	06/10/1912:28
DATE ANALYZED	: 06/10/1916:08	06/10/1916:11	06/10/1916:13
PREP BATCH	: 19HGF009W	19HGF009W	19HGF009W
CALIBRATION REF:	M47F006	M47F006	M47F006

ACCESSION:

PARAMETERS	MBResult (ug/L)	SpikeAmt (ug/L)	LCSResult (ug/L)	LCSRec (%)	SpikeAmt (ug/L)	LCDResult (ug/L)	LCDRec (%)	RPD (%)	QCLimit (%)	MaxRPD (%)
Mercury	ND	2.50	2.59	104	2.50	2.53	101	2	80-120	20

MB: Method Blank sample LCS: Lab Control Sample LCD: Lab Control Sample Duplicate

EMAX QUALITY CONTROL DATA
MS/MSD ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO. : 19F012
METHOD : METHOD 1311/7470A

MATRIX	: LEACHATE		% MOISTURE:NA
DILUTION FACTOR:	1	1	1
SAMPLE ID	: 190104	190104MS	190104MSD
LAB SAMPLE ID	: F012-01	F012-01M	F012-01S
LAB FILE ID	: M47F006042	M47F006044	M47F006047
DATE PREPARED	: 06/10/1912:28	06/10/1912:28	06/10/1912:28
DATE ANALYZED	: 06/10/1917:15	06/10/1917:19	06/10/1917:43
PREP BATCH	: 19HGF009W	19HGF009W	19HGF009W
CALIBRATION REF:	M47F006	M47F006	M47F006

ACCESSION:

PARAMETERS	PSResult (ug/L)	SpikeAmt (ug/L)	MSResult (ug/L)	MSRec (%)	SpikeAmt (ug/L)	MSDResult (ug/L)	MSDRec (%)	RPD (%)	QCLimit (%)	MaxRPD (%)
Mercury	ND	25.0	25.9	104	25.0	26.1	104	1	80-120	20

PS: Parent Sample MS: Matrix Spike MSD: Matrix Spike Duplicate

LABORATORY REPORT FOR

PUNA GEOTHERMAL VENTURE

SEMI-ANNUAL GROUNDWATER SAMPLING

WET CHEMICAL ANALYSES

SDG#: 19F012

CASE NARRATIVE

Client : PUNA GEOTHERMAL VENTURE

Project: SEMI-ANNUAL GROUNDWATER SAMPLING

SDG : 19F012

METHOD 120.1
SPECIFIC CONDUCTIVITY

A total of two(2) water samples were received on 06/04/19 to be analyzed for Specific Conductivity in accordance with Method 120.1 and project specific requirements.

Holding Time
Samples were analyzed within the prescribed holding time.

Calibration
Calibration was performed as specified by the method. All calibration requirements were within acceptance criteria.

Matrix QC Sample
No matrix QC sample was provided on this SDG.

Sample Analysis
Samples were analyzed according to prescribed analytical procedures. Results were evaluated in accordance to project requirements. For this SDG, all quality control requirements were met.

METHOD 120.1
SPECIFIC CONDUCTIVITY

Client : PUNA GEOTHERMAL VENTURE
Project : SEMI-ANNUAL GROUNDWATER SAMPLING
Batch No. : 19F012

Matrix : WATER
InstrumentID : D4

CLIENT SAMPLE ID	EMAX SAMPLE ID	RESULTS (umhos/cm)	PREP FACTOR	MOIST (%)	RL (umhos/cm)	MDL (umhos/cm)	ANALYSIS DATETIME	PREPARATION DATETIME	DATA FILE ID	CAL REF	PREP BATCH	COLLECTION DATETIME	RECEIVED DATETIME
190104	F012-01	5960	1	NA	2	2	06/04/1917:51	NA	19ECF00101	19ECF001	ECF001W	06/03/1909:00	06/04/19
190107	F012-02	6050	1	NA	2	2	06/04/1917:52	NA	19ECF00102	19ECF001	ECF001W	06/03/1910:00	06/04/19

CASE NARRATIVE

Client : PUNA GEOTHERMAL VENTURE

Project: SEMI-ANNUAL GROUNDWATER SAMPLING

SDG : 19F012

METHOD 300.0
BROMIDE

A total of two(2) water samples were received on 06/04/19 to be analyzed for Bromide in accordance with Method 300.0 and project specific requirements.

Holding Time
Samples were analyzed within the prescribed holding time.

Calibration
Multi-calibration points were generated to establish initial calibration (ICAL). ICAL was verified using a secondary source (ICV). Continuing calibration (CCV) verifications were carried out on a frequency specified by the project. All calibration requirements were within acceptance criteria.

Method Blank
Method blank was prepared and analyzed at the frequency required by the project. For this SDG, one(1) method blank was analyzed. Bromide was not detected in ICF002WB. Refer to sample result summary form for details.

Lab Control Sample
Lab control sample was prepared and analyzed at a frequency required by the project. For this SDG, one(1) set of LCS/LCD was analyzed. ICF002WL/ICF002WC were within LCS limits. Refer to LCS summary form for details.

Matrix QC Sample
Matrix spike sample was prepared and analyzed at a frequency required by the project. For this SDG, one(1) set of MS/MSD was analyzed. Bromide was within MS QC limits in F012-02JM/F012-02JS. Sample duplicate was analyzed and RPD was within expected value. Refer to Matrix QC summary forms for details.

Sample Analysis
Samples were analyzed according to prescribed analytical procedures. Results were evaluated in accordance to project requirements. For this SDG, all quality control requirements were met.

CASE NARRATIVE

Client : PUNA GEOTHERMAL VENTURE

Project: SEMI-ANNUAL GROUNDWATER SAMPLING

SDG : 19F012

METHOD 300.0
CHLORIDE

A total of two(2) water samples were received on 06/04/19 to be analyzed for Chloride in accordance with Method 300.0 and project specific requirements.

Holding Time
Samples were analyzed within the prescribed holding time.

Calibration
Multi-calibration points were generated to establish initial calibration (ICAL). ICAL was verified using a secondary source (ICV). Continuing calibration (CCV) verifications were carried out on a frequency specified by the project. All calibration requirements were within acceptance criteria.

Method Blank
Method blank was prepared and analyzed at the frequency required by the project. For this SDG, one(1) method blank was analyzed. Chloride was not detected in ICF002WB. Refer to sample result summary form for details.

Lab Control Sample
Lab control sample was prepared and analyzed at a frequency required by the project. For this SDG, one(1) set of LCS/LCD was analyzed. ICF002WL/ICF002WC were within LCS limits. Refer to LCS summary form for details.

Matrix QC Sample
Matrix spike sample was prepared and analyzed at a frequency required by the project. For this SDG, one(1) set of MS/MSD was analyzed. Chloride was within MS QC limits in F012-02TM/F012-02TS. Sample duplicate was analyzed and RPD was within expected value. Refer to Matrix QC summary forms for details.

Sample Analysis
Samples were analyzed according to prescribed analytical procedures. Results were evaluated in accordance to project requirements. For this SDG, all quality control requirements were met.

CASE NARRATIVE

Client : PUNA GEOTHERMAL VENTURE

Project: SEMI-ANNUAL GROUNDWATER SAMPLING

SDG : 19F012

METHOD 300.0
FLUORIDE

A total of two(2) water samples were received on 06/04/19 to be analyzed for Fluoride in accordance with Method 300.0 and project specific requirements.

Holding Time
Samples were analyzed within the prescribed holding time.

Calibration
Multi-calibration points were generated to establish initial calibration (ICAL). ICAL was verified using a secondary source (ICV). Continuing calibration (CCV) verifications were carried out on a frequency specified by the project. All calibration requirements were within acceptance criteria.

Method Blank
Method blank was prepared and analyzed at the frequency required by the project. For this SDG, one(1) method blank was analyzed. Fluoride was not detected in ICF002WB. Refer to sample result summary form for details.

Lab Control Sample
Lab control sample was prepared and analyzed at a frequency required by the project. For this SDG, one(1) set of LCS/LCD was analyzed. ICF002WL/ICF002WC were within LCS limits. Refer to LCS summary form for details.

Matrix QC Sample
Matrix spike sample was prepared and analyzed at a frequency required by the project. For this SDG, one(1) set of MS/MSD was analyzed. Fluoride was within MS QC limits in F012-02M/F012-02S. Sample duplicate was analyzed and RPD was within expected value. Refer to Matrix QC summary forms for details.

Sample Analysis
Samples were analyzed according to prescribed analytical procedures. Results were evaluated in accordance to project requirements. For this SDG, all quality control requirements were met.

CASE NARRATIVE

Client : PUNA GEOTHERMAL VENTURE

Project: SEMI-ANNUAL GROUNDWATER SAMPLING

SDG : 19F012

METHOD 300.0
NITRATE/NITRITE-N

A total of two(2) water samples were received on 06/04/19 to be analyzed for Nitrate/Nitrite-N in accordance with Method 300.0 and project specific requirements.

Holding Time
Samples were analyzed within the prescribed holding time.

Calibration
Multi-calibration points were generated to establish initial calibration (ICAL). ICAL was verified using a secondary source (ICV). Continuing calibration (CCV) verifications were carried out on a frequency specified by the project. All calibration requirements were within acceptance criteria.

Method Blank
Method blank was prepared and analyzed at the frequency required by the project. For this SDG, one(1) method blank was analyzed. Nitrate/Nitrite-N was not detected in ICF002WB. Refer to sample result summary form for details.

Lab Control Sample
Lab control sample was prepared and analyzed at a frequency required by the project. For this SDG, one(1) set of LCS/LCD was analyzed. ICF002WL/ICF002WC were within LCS limits. Refer to LCS summary form for details.

Matrix QC Sample
Matrix spike sample was prepared and analyzed at a frequency required by the project. For this SDG, one(1) set of MS/MSD was analyzed and the following was noted: F012-02M/F012-02S - Percent recovery for Nitrate/Nitrite-N was not within MS/MSD QC limits. Presence of matrix interference was suspected. Sample duplicate was analyzed and RPD was within expected value. Refer to Matrix QC summary forms for details.

Sample Analysis
Samples were analyzed according to prescribed analytical procedures. Results were evaluated in accordance to project requirements. For this SDG, all quality control requirements were met with the exception of those that were discussed within the associated QC parameter.

Samples 19F012-01I and 19F012-02J were reported at dilution factor > 1 for nitrite due to chloride interference. Refer to sample result forms for details.

CASE NARRATIVE

Client : PUNA GEOTHERMAL VENTURE

Project: SEMI-ANNUAL GROUNDWATER SAMPLING

SDG : 19F012

METHOD 300.0
SULFATE

A total of two(2) water samples were received on 06/04/19 to be analyzed for Sulfate in accordance with Method 300.0 and project specific requirements.

Holding Time
Samples were analyzed within the prescribed holding time.

Calibration
Multi-calibration points were generated to establish initial calibration (ICAL). ICAL was verified using a secondary source (ICV). Continuing calibration (CCV) verifications were carried out on a frequency specified by the project. All calibration requirements were within acceptance criteria.

Method Blank
Method blank was prepared and analyzed at the frequency required by the project. For this SDG, one(1) method blank was analyzed. Sulfate was not detected in ICF002WB. Refer to sample result summary form for details.

Lab Control Sample
Lab control sample was prepared and analyzed at a frequency required by the project. For this SDG, one(1) set of LCS/LCD was analyzed. ICF002WL/ICF002WC were within LCS limits. Refer to LCS summary form for details.

Matrix QC Sample
Matrix spike sample was prepared and analyzed at a frequency required by the project. For this SDG, one(1) set of MS/MSD was analyzed. Sulfate was within MS QC limits in F012-02IM/F012-02IS. Sample duplicate was analyzed and RPD was within expected value. Refer to Matrix QC summary forms for details.

Sample Analysis
Samples were analyzed according to prescribed analytical procedures. Results were evaluated in accordance to project requirements. For this SDG, all quality control requirements were met.

SAMPLE RESULTS

METHOD 300.0
BROMIDE

Client : PUNA GEOTHERMAL VENTURE
Project : SEMI-ANNUAL GROUNDWATER SAMPLING
Batch No. : 19F012

Matrix : WATER
InstrumentID : D7

CLIENT SAMPLE ID	EMAX SAMPLE ID	RESULTS (mg/L)	DFxPREP FACTOR	MOIST (%)	RL (mg/L)	MDL (mg/L)	ANALYSIS DATETIME	PREPARATION DATETIME	DATA FILE ID	CAL REF	PREP BATCH	COLLECTION DATETIME	RECEIVED DATETIME
MBLK1W	ICF002WB	ND	1	NA	0.5	0.25	06/04/1911:30	NA	AF02-03	AF02-01	ICF002W	NA	NA
LCS1W	ICF002WL	1.82	1	NA	0.5	0.25	06/04/1911:51	NA	AF02-04	AF02-01	ICF002W	NA	NA
LCD1W	ICF002WC	1.83	1	NA	0.5	0.25	06/04/1912:12	NA	AF02-05	AF02-01	ICF002W	NA	NA
190107	F012-02J	7.29	10	NA	5	2.5	06/04/1913:41	NA	AF02-09	AF02-01	ICF002W	06/03/1910:00	06/04/19
190107MS	F012-02JM	25.7	10	NA	5	2.5	06/04/1914:22	NA	AF02-11	AF02-01	ICF002W	06/03/1910:00	06/04/19
190104	F012-01I	7.19	10	NA	5	2.5	06/04/1916:08	NA	AF02-16	AF02-13	ICF002W	06/03/1909:00	06/04/19
190107DUP	F012-02JD	7.31	10	NA	5	2.5	06/04/1918:33	NA	AF02-23	AF02-13	ICF002W	06/03/1910:00	06/04/19
190107MSD	F012-02JS	25.6	10	NA	5	2.5	06/04/1918:54	NA	AF02-24	AF02-13	ICF002W	06/03/1910:00	06/04/19

METHOD 300.0
CHLORIDE

Client : PUNA GEOTHERMAL VENTURE
Project : SEMI-ANNUAL GROUNDWATER SAMPLING
Batch No. : 19F012

Matrix : WATER
InstrumentID : D7

CLIENT SAMPLE ID	EMAX SAMPLE ID	RESULTS (mg/L)	DFxPREP FACTOR	MOIST (%)	RL (mg/L)	MDL (mg/L)	ANALYSIS DATETIME	PREPARATION DATETIME	DATA FILE ID	CAL REF	PREP BATCH	COLLECTION DATETIME	RECEIVED DATETIME
MBLK1W	ICF002WB	ND	1	NA	0.2	0.1	06/04/1911:30	NA	AF02-03	AF02-01	ICF002W	NA	NA
LCS1W	ICF002WL	1.91	1	NA	0.2	0.1	06/04/1911:51	NA	AF02-04	AF02-01	ICF002W	NA	NA
LCD1W	ICF002WC	1.93	1	NA	0.2	0.1	06/04/1912:12	NA	AF02-05	AF02-01	ICF002W	NA	NA
190107	F012-02T	2170	2000	NA	400	200	06/04/1916:29	NA	AF02-17	AF02-13	ICF002W	06/03/1910:00	06/04/19
190104	F012-01K	2380	1000	NA	200	100	06/04/1920:59	NA	AF02-30	AF02-25	ICF002W	06/03/1909:00	06/04/19
190107DUP	F012-02TD	2210	2000	NA	400	200	06/04/1921:19	NA	AF02-31	AF02-25	ICF002W	06/03/1910:00	06/04/19
190107MS	F012-02TM	6250	2000	NA	400	200	06/04/1921:40	NA	AF02-32	AF02-25	ICF002W	06/03/1910:00	06/04/19
190107MSD	F012-02TS	6290	2000	NA	400	200	06/04/1922:01	NA	AF02-33	AF02-25	ICF002W	06/03/1910:00	06/04/19

METHOD 300.0
FLUORIDE

Client : PUNA GEOTHERMAL VENTURE
Project : SEMI-ANNUAL GROUNDWATER SAMPLING
Batch No. : 19F012

Matrix : WATER
InstrumentID : D7

CLIENT SAMPLE ID	EMAX SAMPLE ID	RESULTS (mg/L)	DFxPREP FACTOR	MOIST (%)	RL (mg/L)	MDL (mg/L)	ANALYSIS DATETIME	PREPARATION DATETIME	DATA FILE ID	CAL REF	PREP BATCH	COLLECTION DATETIME	RECEIVED DATETIME
MBLK1W	ICF002WB	ND	1	NA	0.1	0.05	06/04/1911:30	NA	AF02-03	AF02-01	ICF002W	NA	NA
LCS1W	ICF002WL	1.05	1	NA	0.1	0.05	06/04/1911:51	NA	AF02-04	AF02-01	ICF002W	NA	NA
LCD1W	ICF002WC	1.06	1	NA	0.1	0.05	06/04/1912:12	NA	AF02-05	AF02-01	ICF002W	NA	NA
190104	F012-01	0.380	1	NA	0.1	0.05	06/04/1912:32	NA	AF02-06	AF02-01	ICF002W	06/03/1909:00	06/04/19
190107	F012-02	0.384	1	NA	0.1	0.05	06/04/1912:53	NA	AF02-07	AF02-01	ICF002W	06/03/1910:00	06/04/19
190107MS	F012-02M	1.42	1	NA	0.1	0.05	06/04/1914:01	NA	AF02-10	AF02-01	ICF002W	06/03/1910:00	06/04/19
190107DUP	F012-02D	0.381	1	NA	0.1	0.05	06/04/1919:56	NA	AF02-27	AF02-25	ICF002W	06/03/1910:00	06/04/19
190107MSD	F012-02S	1.44	1	NA	0.1	0.05	06/04/1920:17	NA	AF02-28	AF02-25	ICF002W	06/03/1910:00	06/04/19

METHOD 300.0
NITRATE/NITRITE-N

Client : PUNA GEOTHERMAL VENTURE
Project : SEMI-ANNUAL GROUNDWATER SAMPLING
Batch No. : 19F012

Matrix : WATER
InstrumentID : D7

CLIENT SAMPLE ID	EMAX SAMPLE ID	RESULTS (mg/L)	DFxPREP FACTOR	MOIST (%)	RL (mg/L)	MDL (mg/L)	ANALYSIS DATETIME	PREPARATION DATETIME	DATA FILE ID	CAL REF	PREP BATCH	COLLECTION DATETIME	RECEIVED DATETIME
MBLK1W	ICF002WB	ND	1	NA	0.1	0.05	06/04/1911:30	NA	AF02-03	AF02-01	ICF002W	NA	NA
LCS1W	ICF002WL	3.04	1	NA	0.1	0.05	06/04/1911:51	NA	AF02-04	AF02-01	ICF002W	NA	NA
LCD1W	ICF002WC	3.05	1	NA	0.1	0.05	06/04/1912:12	NA	AF02-05	AF02-01	ICF002W	NA	NA
190104	F012-01	0.0658J	1	NA	0.1	0.05	06/04/1912:32	NA	AF02-06	AF02-01	ICF002W	06/03/1909:00	06/04/19
190107	F012-02	0.0688J	1	NA	0.1	0.05	06/04/1912:53	NA	AF02-07	AF02-01	ICF002W	06/03/1910:00	06/04/19
190107MS	F012-02M	15.6	1	NA	0.1	0.05	06/04/1914:01	NA	AF02-10	AF02-01	ICF002W	06/03/1910:00	06/04/19
190107DUP	F012-02D	0.0650J	1	NA	0.1	0.05	06/04/1919:56	NA	AF02-27	AF02-25	ICF002W	06/03/1910:00	06/04/19
190107MSD	F012-02S	15.5	1	NA	0.1	0.05	06/04/1920:17	NA	AF02-28	AF02-25	ICF002W	06/03/1910:00	06/04/19

METHOD 300.0
SULFATE

Client : PUNA GEOTHERMAL VENTURE
Project : SEMI-ANNUAL GROUNDWATER SAMPLING
Batch No. : 19F012

Matrix : WATER
InstrumentID : D7

CLIENT SAMPLE ID	EMAX SAMPLE ID	RESULTS (mg/L)	DFxPREP FACTOR	MOIST (%)	RL (mg/L)	MDL (mg/L)	ANALYSIS DATETIME	PREPARATION DATETIME	DATA FILE ID	CAL REF	PREP BATCH	COLLECTION DATETIME	RECEIVED DATETIME
MBLK1W	ICF002WB	ND	1	NA	0.5	0.25	06/04/1911:30	NA	AF02-03	AF02-01	ICF002W	NA	NA
LCS1W	ICF002WL	4.90	1	NA	0.5	0.25	06/04/1911:51	NA	AF02-04	AF02-01	ICF002W	NA	NA
LCD1W	ICF002WC	5.09	1	NA	0.5	0.25	06/04/1912:12	NA	AF02-05	AF02-01	ICF002W	NA	NA
190107	F012-02I	316	100	NA	50	25	06/04/1913:18	NA	AF02-08	AF02-01	ICF002W	06/03/1910:00	06/04/19
190107DUP	F012-02ID	307	100	NA	50	25	06/04/1914:43	NA	AF02-12	AF02-01	ICF002W	06/03/1910:00	06/04/19
190104	F012-01J	342	50	NA	25	12.5	06/04/1920:38	NA	AF02-29	AF02-25	ICF002W	06/03/1909:00	06/04/19
190107MS	F012-02IM	837	100	NA	50	25	06/04/1922:22	NA	AF02-34	AF02-25	ICF002W	06/03/1910:00	06/04/19
190107MSD	F012-02IS	834	100	NA	50	25	06/04/1922:42	NA	AF02-35	AF02-25	ICF002W	06/03/1910:00	06/04/19

QC SUMMARIES

EMAX QUALITY CONTROL DATA
LAB CONTROL SAMPLE ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO. : 19F012
METHOD : 300.0

MATRIX	: WATER		% MOISTURE: NA
DILUTION FACTOR:	1	1	1
SAMPLE ID	: MBLK1W	LCS1W	LCD1W
LAB SAMPLE ID	: ICF002WB	ICF002WL	ICF002WC
LAB FILE ID	: AF02-03	AF02-04	AF02-05
DATE PREPARED	: NA	NA	NA
DATE ANALYZED	: 06/04/1911:30	06/04/1911:51	06/04/1912:12
PREP BATCH	: ICF002W	ICF002W	ICF002W
CALIBRATION REF:	AF02-01	AF02-01	AF02-01

ACCESSION:

PARAMETER	MB RESULT (mg/L)	SPIKE AMT (mg/L)	BS RESULT (mg/L)	BS REC (%)	SPIKE AMT (mg/L)	BSD RESULT (mg/L)	BSD REC (%)	RPD (%)	QC LIMIT (%)	MAX RPD (%)
Bromide	ND	2	1.82	91	2	1.83	92	1	90-110	20

EMAX QUALITY CONTROL DATA
MS/MSD ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO. : 19F012
METHOD : 300.0

MATRIX	: WATER		% MOISTURE: NA
DILUTION FACTOR	: 10	10	10
SAMPLE ID	: 190107	190107MS	190107MSD
LAB SAMPLE ID	: F012-02J	F012-02JM	F012-02JS
LAB FILE ID	: AF02-09	AF02-11	AF02-24
DATE PREPARED	: NA	NA	NA
DATE ANALYZED	: 06/04/1913:41	06/04/1914:22	06/04/1918:54
PREP BATCH	: ICF002W	ICF002W	ICF002W
CALIBRATION REF	: AF02-01	AF02-01	AF02-13

ACCESSION:

PARAMETER	PARENT RESULT (mg/L)	SPIKE AMT (mg/L)	MS RESULT (mg/L)	MS REC (%)	SPIKE AMT (mg/L)	MSD RESULT (mg/L)	MSD REC (%)	RPD (%)	QC LIMIT (%)	MAX RPD (%)
Bromide	7.29	20	25.7	92	20	25.6	92	0	80-120	20

EMAX QUALITY CONTROL DATA
SAMPLE DUPLICATE ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO. : 19F012
METHOD : 300.0

MATRIX	: WATER	
DILUTION FACTOR	: 10	10
SAMPLE ID	: 190107	190107DUP
LAB SAMPLE ID	: F012-02J	F012-02JD
LAB FILE ID	: AF02-09	AF02-23
DATE PREPARED	: NA	NA
DATE ANALYZED	: 06/04/1913:41	06/04/1918:33
PREP BATCH	: ICF002W	ICF002W
CALIBRATION REF	: AF02-13	AF02-13

ACCESSION:

PARAMETER	PARENT RESULT (mg/L)	DUP RESULT (mg/L)	RPD (%)	MAX RPD (%)
Bromide	7.29	7.31	0	20

EMAX QUALITY CONTROL DATA
LAB CONTROL SAMPLE ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO. : 19F012
METHOD : 300.0

MATRIX	: WATER			% MOISTURE: NA
DILUTION FACTOR:	1	1	1	
SAMPLE ID	: MBLK1W	LCS1W	LCD1W	
LAB SAMPLE ID	: ICF002WB	ICF002WL	ICF002WC	
LAB FILE ID	: AF02-03	AF02-04	AF02-05	
DATE PREPARED	: NA	NA	NA	
DATE ANALYZED	: 06/04/1911:30	06/04/1911:51	06/04/1912:12	
PREP BATCH	: ICF002W	ICF002W	ICF002W	
CALIBRATION REF:	AF02-01	AF02-01	AF02-01	

ACCESSION:

PARAMETER	MB RESULT (mg/L)	SPIKE AMT (mg/L)	BS RESULT (mg/L)	BS REC (%)	SPIKE AMT (mg/L)	BSD RESULT (mg/L)	BSD REC (%)	RPD (%)	QC LIMIT (%)	MAX RPD (%)
Chloride	ND	2	1.91	95	2	1.93	96	1	90-110	20

EMAX QUALITY CONTROL DATA
MS/MSD ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO. : 19F012
METHOD : 300.0

MATRIX	: WATER		% MOISTURE: NA
DILUTION FACTOR	: 2000	2000	2000
SAMPLE ID	: 190107	190107MS	190107MSD
LAB SAMPLE ID	: F012-02T	F012-02TM	F012-02TS
LAB FILE ID	: AF02-17	AF02-32	AF02-33
DATE PREPARED	: NA	NA	NA
DATE ANALYZED	: 06/04/1916:29	06/04/1921:40	06/04/1922:01
PREP BATCH	: ICF002W	ICF002W	ICF002W
CALIBRATION REF	: AF02-13	AF02-25	AF02-25

ACCESSION:

PARAMETER	PARENT RESULT (mg/L)	SPIKE AMT (mg/L)	MS RESULT (mg/L)	MS REC (%)	SPIKE AMT (mg/L)	MSD RESULT (mg/L)	MSD REC (%)	RPD (%)	QC LIMIT (%)	MAX RPD (%)
Chloride	2170	4000	6250	102	4000	6290	103	1	80-120	20

EMAX QUALITY CONTROL DATA
SAMPLE DUPLICATE ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO. : 19F012
METHOD : 300.0

MATRIX	: WATER	
DILUTION FACTOR:	2000	2000
SAMPLE ID	: 190107	190107DUP
LAB SAMPLE ID	: F012-02T	F012-02TD
LAB FILE ID	: AF02-17	AF02-31
DATE PREPARED	: NA	NA
DATE ANALYZED	: 06/04/1916:29	06/04/1921:19
PREP BATCH	: ICF002W	ICF002W
CALIBRATION REF:	AF02-25	AF02-25

ACCESSION:

PARAMETER	PARENT RESULT (mg/L)	DUP RESULT (mg/L)	RPD (%)	MAX RPD (%)
Chloride	2170	2210	2	20

EMAX QUALITY CONTROL DATA
LAB CONTROL SAMPLE ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO. : 19F012
METHOD : 300.0

MATRIX	: WATER			% MOISTURE: NA
DILUTION FACTOR:	1	1	1	
SAMPLE ID	: MBLK1W	LCS1W	LCD1W	
LAB SAMPLE ID	: ICF002WB	ICF002WL	ICF002WC	
LAB FILE ID	: AF02-03	AF02-04	AF02-05	
DATE PREPARED	: NA	NA	NA	
DATE ANALYZED	: 06/04/1911:30	06/04/1911:51	06/04/1912:12	
PREP BATCH	: ICF002W	ICF002W	ICF002W	
CALIBRATION REF:	AF02-01	AF02-01	AF02-01	

ACCESSION:

PARAMETER	MB RESULT (mg/L)	SPIKE AMT (mg/L)	BS RESULT (mg/L)	BS REC (%)	SPIKE AMT (mg/L)	BSD RESULT (mg/L)	BSD REC (%)	RPD (%)	QC LIMIT (%)	MAX RPD (%)
Fluoride	ND	1	1.05	105	1	1.06	106	1	90-110	20

EMAX QUALITY CONTROL DATA
MS/MSD ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO. : 19F012
METHOD : 300.0

MATRIX	: WATER		% MOISTURE: NA
DILUTION FACTOR:	1	1	1
SAMPLE ID	: 190107	190107MS	190107MSD
LAB SAMPLE ID	: F012-02	F012-02M	F012-02S
LAB FILE ID	: AF02-07	AF02-10	AF02-28
DATE PREPARED	: NA	NA	NA
DATE ANALYZED	: 06/04/1912:53	06/04/1914:01	06/04/1920:17
PREP BATCH	: ICF002W	ICF002W	ICF002W
CALIBRATION REF:	AF02-01	AF02-01	AF02-25

ACCESSION:

PARAMETER	PARENT RESULT (mg/L)	SPIKE AMT (mg/L)	MS RESULT (mg/L)	MS REC (%)	SPIKE AMT (mg/L)	MSD RESULT (mg/L)	MSD REC (%)	RPD (%)	QC LIMIT (%)	MAX RPD (%)
Fluoride	0.384	1	1.42	104	1	1.44	106	1	80-120	20

EMAX QUALITY CONTROL DATA
SAMPLE DUPLICATE ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO. : 19F012
METHOD : 300.0

MATRIX	: WATER	
DILUTION FACTOR:	1	1
SAMPLE ID	: 190107	190107DUP
LAB SAMPLE ID	: F012-02	F012-02D
LAB FILE ID	: AF02-07	AF02-27
DATE PREPARED	: NA	NA
DATE ANALYZED	: 06/04/1912:53	06/04/1919:56
PREP BATCH	: ICF002W	ICF002W
CALIBRATION REF:	AF02-25	AF02-25

ACCESSION:

PARAMETER	PARENT RESULT (mg/L)	DUP RESULT (mg/L)	RPD (%)	MAX RPD (%)
Fluoride	0.384	0.381	1	20

EMAX QUALITY CONTROL DATA
LAB CONTROL SAMPLE ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO. : 19F012
METHOD : 300.0

MATRIX	: WATER			% MOISTURE: NA
DILUTION FACTOR:	1	1	1	
SAMPLE ID	: MBLK1W	LCS1W	LCD1W	
LAB SAMPLE ID	: ICF002WB	ICF002WL	ICF002WC	
LAB FILE ID	: AF02-03	AF02-04	AF02-05	
DATE PREPARED	: NA	NA	NA	
DATE ANALYZED	: 06/04/1911:30	06/04/1911:51	06/04/1912:12	
PREP BATCH	: ICF002W	ICF002W	ICF002W	
CALIBRATION REF:	AF02-01	AF02-01	AF02-01	

ACCESSION:

PARAMETER	MB RESULT (mg/L)	SPIKE AMT (mg/L)	BS RESULT (mg/L)	BS REC (%)	SPIKE AMT (mg/L)	BSD RESULT (mg/L)	BSD REC (%)	RPD (%)	QC LIMIT (%)	MAX RPD (%)
NITRATE/NITRITE-N	ND	3	3.04	101	3	3.05	102	0	90-110	20

EMAX QUALITY CONTROL DATA
MS/MSD ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO. : 19F012
METHOD : 300.0

MATRIX : WATER		% MOISTURE: NA	
DILUTION FACTOR: 1	1	1	
SAMPLE ID : 190107	190107MS	190107MSD	
LAB SAMPLE ID : F012-02	F012-02M	F012-02S	
LAB FILE ID : AF02-07	AF02-10	AF02-28	
DATE PREPARED : NA	NA	NA	
DATE ANALYZED : 06/04/1912:53	06/04/1914:01	06/04/1920:17	
PREP BATCH : ICF002W	ICF002W	ICF002W	
CALIBRATION REF: AF02-01	AF02-01	AF02-25	

ACCESSION:

PARAMETER	PARENT RESULT (mg/L)	SPIKE AMT (mg/L)	MS RESULT (mg/L)	MS REC (%)	SPIKE AMT (mg/L)	MSD RESULT (mg/L)	MSD REC (%)	RPD (%)	QC LIMIT (%)	MAX RPD (%)
NITRATE/NITRITE-N	0.0688J	21	15.6	74*	21	15.5	73*	1	80-120	20

* Out of MS QC limit.

EMAX QUALITY CONTROL DATA
SAMPLE DUPLICATE ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO. : 19F012
METHOD : 300.0

MATRIX	: WATER	
DILUTION FACTOR:	1	1
SAMPLE ID	: 190107	190107DUP
LAB SAMPLE ID	: F012-02	F012-02D
LAB FILE ID	: AF02-07	AF02-27
DATE PREPARED	: NA	NA
DATE ANALYZED	: 06/04/1912:53	06/04/1919:56
PREP BATCH	: ICF002W	ICF002W
CALIBRATION REF:	AF02-25	AF02-25

ACCESSION:

PARAMETER	PARENT RESULT (mg/L)	DUP RESULT (mg/L)	RPD (%)	MAX RPD (%)
NITRATE/NITRITE-N	0.0688J	0.065J	NA	20

EMAX QUALITY CONTROL DATA
LAB CONTROL SAMPLE ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO. : 19F012
METHOD : 300.0

MATRIX	: WATER			% MOISTURE: NA
DILUTION FACTOR:	1	1	1	
SAMPLE ID	: MBLK1W	LCS1W	LCD1W	
LAB SAMPLE ID	: ICF002WB	ICF002WL	ICF002WC	
LAB FILE ID	: AF02-03	AF02-04	AF02-05	
DATE PREPARED	: NA	NA	NA	
DATE ANALYZED	: 06/04/1911:30	06/04/1911:51	06/04/1912:12	
PREP BATCH	: ICF002W	ICF002W	ICF002W	
CALIBRATION REF:	AF02-01	AF02-01	AF02-01	

ACCESSION:

PARAMETER	MB RESULT (mg/L)	SPIKE AMT (mg/L)	BS RESULT (mg/L)	BS REC (%)	SPIKE AMT (mg/L)	BSD RESULT (mg/L)	BSD REC (%)	RPD (%)	QC LIMIT (%)	MAX RPD (%)
Sulfate	ND	5	4.90	98	5	5.09	102	4	90-110	20

EMAX QUALITY CONTROL DATA
MS/MSD ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO. : 19F012
METHOD : 300.0

MATRIX	: WATER		% MOISTURE: NA
DILUTION FACTOR:	100	100	100
SAMPLE ID	: 190107	190107MS	190107MSD
LAB SAMPLE ID	: F012-02I	F012-02IM	F012-02IS
LAB FILE ID	: AF02-08	AF02-34	AF02-35
DATE PREPARED	: NA	NA	NA
DATE ANALYZED	: 06/04/1913:18	06/04/1922:22	06/04/1922:42
PREP BATCH	: ICF002W	ICF002W	ICF002W
CALIBRATION REF:	AF02-01	AF02-25	AF02-25

ACCESSION:

PARAMETER	PARENT RESULT (mg/L)	SPIKE AMT (mg/L)	MS RESULT (mg/L)	MS REC (%)	SPIKE AMT (mg/L)	MSD RESULT (mg/L)	MSD REC (%)	RPD (%)	QC LIMIT (%)	MAX RPD (%)
Sulfate	316	500	837	104	500	834	104	0	80-120	20

EMAX QUALITY CONTROL DATA
SAMPLE DUPLICATE ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO. : 19F012
METHOD : 300.0

MATRIX	: WATER	
DILUTION FACTOR	: 100	100
SAMPLE ID	: 190107	190107DUP
LAB SAMPLE ID	: F012-02I	F012-02ID
LAB FILE ID	: AF02-08	AF02-12
DATE PREPARED	: NA	NA
DATE ANALYZED	: 06/04/1913:18	06/04/1914:43
PREP BATCH	: ICF002W	ICF002W
CALIBRATION REF	: AF02-01	AF02-01

ACCESSION:

PARAMETER	PARENT RESULT (mg/L)	DUP RESULT (mg/L)	RPD (%)	MAX RPD (%)
Sulfate	316	307	3	20

CASE NARRATIVE

Client : PUNA GEOTHERMAL VENTURE

Project: SEMI-ANNUAL GROUNDWATER SAMPLING

SDG : 19F012

METHOD SW1010
IGNITABILITY

A total of two(2) water samples were received on 06/04/19 to be analyzed for Ignitability in accordance with Method SW1010 and project specific requirements.

Holding Time
Samples were analyzed within the prescribed holding time.

Calibration
Calibration was performed as specified by the method. All calibration requirements were within acceptance criteria.

Lab Control Sample
Lab control sample was prepared and analyzed at a frequency required by the project. For this SDG, one(1) LCS was analyzed. Percent recovery for Ignitability was within LCS QC limits in IGF001L. Refer to LCS summary form for details.

Matrix QC Sample
No matrix QC sample was provided on this SDG.

Sample Analysis
Samples were analyzed according to prescribed analytical procedures. Results were evaluated in accordance to project requirements. For this SDG, all quality control requirements were met.

SW1010
IGNITABILITY

Client	: PUNA GEOTHERMAL VENTURE	Matrix	: WATER
Project	: SEMI-ANNUAL GROUNDWATER SAMPLING	InstrumentID	: 28
Batch No.	: 19F012		

CLIENT SAMPLE ID	EMAX SAMPLE ID	RESULTS (oC)	PREP FACTOR	MOIST (%)	RL (oC)	MDL (oC)	ANALYSIS DATETIME	PREPARATION DATETIME	DATA FILE ID	CAL REF	PREP BATCH	COLLECTION DATETIME	RECEIVED DATETIME
LCS1	IGF001L	51	1	NA	NA	NA	06/13/1916:39	NA	19IGF00101	19IGF001	IGF001	NA	NA
190104	F012-01	100>	1	NA	NA	NA	06/13/1916:59	NA	19IGF00102	19IGF001	IGF001	06/03/1909:00	06/04/19
190107	F012-02	100>	1	NA	NA	NA	06/13/1917:19	NA	19IGF00103	19IGF001	IGF001	06/03/1910:00	06/04/19

> : No flash at 100 degrees C

EMAX QUALITY CONTROL DATA
LCS ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO. : 19F012
METHOD : SW1010

MATRIX	: N-DECANE	
DILUTION FACTOR	: NA	1
SAMPLE ID	: NA	LCS1
LAB SAMPLE ID	: NA	IGF001L
LAB FILE ID	: NA	19IGF00101
DATE PREPARED	: NA	06/13/1916:39
DATE ANALYZED	: NA	06/13/1916:39
PREP BATCH	: NA	IGF001
CALIBRATION REF	: NA	19IGF001

ACCESSION:

PARAMETER	MB RESULT (oC)	EXPECTED (oC)	LCS RESULT (oC)	DIFF (oC)	QC LIMIT (oC)
IGNITABILITY	NA	51.2	51.0	-0.20	48.9-53.5

CASE NARRATIVE

Client : PUNA GEOTHERMAL VENTURE

Project: SEMI-ANNUAL GROUNDWATER SAMPLING

SDG : 19F012

METHOD 2320B
BICARBONATE ALKALINITY

A total of two(2) water samples were received on 06/04/19 to be analyzed for Bicarbonate Alkalinity in accordance with Method 2320B and project specific requirements.

Holding Time
Samples were analyzed within the prescribed holding time.

Calibration
Calibration was performed as prescribed by the method and was verified using a secondary source (ICV). All calibration requirements were within acceptance criteria.

Method Blank
Method blank was prepared and analyzed at the frequency required by the project. For this SDG, one(1) method blank was analyzed. Bicarbonate Alkalinity was not detected in ALF001WB. Refer to sample result summary form for details.

Matrix QC Sample
Sample duplicate was analyzed and RPD was within expected value.

Sample Analysis
Samples were analyzed according to prescribed analytical procedures. Results were evaluated in accordance to project requirements. For this SDG, all quality control requirements were met.

METHOD 2320B
BICARBONATE ALKALINITY

Client : PUNA GEOTHERMAL VENTURE
Project : SEMI-ANNUAL GROUNDWATER SAMPLING
Batch No. : 19F012

Matrix : WATER
InstrumentID : E5

CLIENT SAMPLE ID	EMAX SAMPLE ID	RESULTS (mg/L)	PREP. FACTOR	MOIST (%)	RL (mg/L)	MDL (mg/L)	ANALYSIS DATETIME	PREPARATION DATETIME	DATA FILE ID	CAL REF	PREP BATCH	COLLECTION DATETIME	RECEIVED DATETIME
MBLK1W	ALF001WB	ND	1	NA	5	5	06/06/1914:07	NA	19E5F0103	19E5F01	ALF001W	NA	NA
190104	F012-01	32.5	1	NA	5	5	06/06/1915:20	NA	19E5F0114	19E5F01	ALF001W	06/03/1909:00	06/04/19
190104DUP	F012-01D	32.2	1	NA	5	5	06/06/1915:26	NA	19E5F0115	19E5F01	ALF001W	06/03/1909:00	06/04/19
190107	F012-02	32.3	1	NA	5	5	06/06/1915:33	NA	19E5F0116	19E5F01	ALF001W	06/03/1910:00	06/04/19

EMAX QUALITY CONTROL DATA
SAMPLE DUPLICATE ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO. : 19F012
METHOD : METHOD 2320B

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MATRIX	: WATER	
DILUTION FACTOR	: 1	1
SAMPLE ID	: 190104	190104DUP
LAB SAMPLE ID	: F012-01	F012-01D
LAB FILE ID	: 19E5F0114	19E5F0115
DATE PREPARED	: NA	NA
DATE ANALYZED	: 06/06/1915:20	06/06/1915:26
PREP BATCH	: ALF001W	ALF001W
CALIBRATION REF	: 19E5F011	19E5F011

ACCESSION:

PARAMETER	PARENT RESULT (mg/L)	DUP RESULT (mg/L)	RPD (%)	MAX RPD (%)
BICARBONATE ALKALINITY	32.5	32.2	0.9	20

CASE NARRATIVE

Client : PUNA GEOTHERMAL VENTURE

Project: SEMI-ANNUAL GROUNDWATER SAMPLING

SDG : 19F012

METHOD 2320B
CARBONATE ALKALINITY

A total of two(2) water samples were received on 06/04/19 to be analyzed for Carbonate Alkalinity in accordance with Method 2320B and project specific requirements.

Holding Time
Samples were analyzed within the prescribed holding time.

Calibration
Calibration was performed as prescribed by the method and was verified using a secondary source (ICV). All calibration requirements were within acceptance criteria.

Method Blank
Method blank was prepared and analyzed at the frequency required by the project. For this SDG, one(1) method blank was analyzed. Carbonate Alkalinity was not detected in ALF001WB. Refer to sample result summary form for details.

Matrix QC Sample
Sample duplicate was analyzed and RPD was within expected value.

Sample Analysis
Samples were analyzed according to prescribed analytical procedures. Results were evaluated in accordance to project requirements. For this SDG, all quality control requirements were met.

METHOD 2320B
CARBONATE ALKALINITY

Client	: PUNA GEOTHERMAL VENTURE	Matrix	: WATER
Project	: SEMI-ANNUAL GROUNDWATER SAMPLING	InstrumentID	: E5
Batch No.	: 19F012		

CLIENT SAMPLE ID	EMAX SAMPLE ID	RESULTS (mg/L)	PREP. FACTOR	MOIST (%)	RL (mg/L)	MDL (mg/L)	ANALYSIS DATETIME	PREPARATION DATETIME	DATA FILE ID	CAL REF	PREP BATCH	COLLECTION DATETIME	RECEIVED DATETIME
MBLK1W	ALF001WB	ND	1	NA	5	5	06/06/1914:07	NA	19E5F0103	19E5F01	ALF001W	NA	NA
190104	F012-01	ND	1	NA	5	5	06/06/1915:20	NA	19E5F0114	19E5F01	ALF001W	06/03/1909:00	06/04/19
190104DUP	F012-01D	ND	1	NA	5	5	06/06/1915:26	NA	19E5F0115	19E5F01	ALF001W	06/03/1909:00	06/04/19
190107	F012-02	ND	1	NA	5	5	06/06/1915:33	NA	19E5F0116	19E5F01	ALF001W	06/03/1910:00	06/04/19

EMAX QUALITY CONTROL DATA
SAMPLE DUPLICATE ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO. : 19F012
METHOD : METHOD 2320B

MATRIX	: WATER	
DILUTION FACTOR	: 1	1
SAMPLE ID	: 190104	190104DUP
LAB SAMPLE ID	: F012-01	F012-01D
LAB FILE ID	: 19E5F0114	19E5F0115
DATE PREPARED	: NA	NA
DATE ANALYZED	: 06/06/1915:20	06/06/1915:26
PREP BATCH	: ALF001W	ALF001W
CALIBRATION REF	: 19E5F011	19E5F011

ACCESSION:

PARAMETER	PARENT RESULT (mg/L)	DUP RESULT (mg/L)	RPD (%)	MAX RPD (%)
CARBONATE ALKALINITY	ND	ND	0	20

CASE NARRATIVE

Client : PUNA GEOTHERMAL VENTURE

Project: SEMI-ANNUAL GROUNDWATER SAMPLING

SDG : 19F012

METHOD 2320B
TOTAL ALKALINITY

A total of two(2) water samples were received on 06/04/19 to be analyzed for Total Alkalinity in accordance with Method 2320B and project specific requirements.

Holding Time
Samples were analyzed within the prescribed holding time.

Calibration
Calibration was performed as prescribed by the method and was verified using a secondary source (ICV). All calibration requirements were within acceptance criteria.

Method Blank
Method blank was prepared and analyzed at the frequency required by the project. For this SDG, one(1) method blank was analyzed. Total Alkalinity was not detected in ALF001WB. Refer to sample result summary form for details.

Lab Control Sample
Lab control sample was prepared and analyzed at a frequency required by the project. For this SDG, one(1) set of LCS/LCD was analyzed. ALF001WL/ALF001WC were within LCS limits. Refer to LCS summary form for details.

Matrix QC Sample
Sample duplicate was analyzed and RPD was within expected value.

Sample Analysis
Samples were analyzed according to prescribed analytical procedures. Results were evaluated in accordance to project requirements. For this SDG, all quality control requirements were met.

METHOD 2320B
TOTAL ALKALINITY

Client : PUNA GEOTHERMAL VENTURE
Project : SEMI-ANNUAL GROUNDWATER SAMPLING
Batch No. : 19F012

Matrix : WATER
InstrumentID : E5

CLIENT SAMPLE ID	EMAX SAMPLE ID	RESULTS (mg/L)	PREP. FACTOR	MOIST (%)	RL (mg/L)	MDL (mg/L)	ANALYSIS DATETIME	PREPARATION DATETIME	DATA FILE ID	CAL REF	PREP BATCH	COLLECTION DATETIME	RECEIVED DATETIME
MBLK1W	ALF001WB	ND	1	NA	5	5	06/06/1914:07	NA	19E5F0103	19E5F01	ALF001W	NA	NA
LCS1W	ALF001WL	79.9	1	NA	5	5	06/06/1914:14	NA	19E5F0104	19E5F01	ALF001W	NA	NA
LCD1W	ALF001WC	82.1	1	NA	5	5	06/06/1914:21	NA	19E5F0105	19E5F01	ALF001W	NA	NA
190104	F012-01	32.5	1	NA	5	5	06/06/1915:20	NA	19E5F0114	19E5F01	ALF001W	06/03/1909:00	06/04/19
190104DUP	F012-01D	32.2	1	NA	5	5	06/06/1915:26	NA	19E5F0115	19E5F01	ALF001W	06/03/1909:00	06/04/19
190107	F012-02	32.3	1	NA	5	5	06/06/1915:33	NA	19E5F0116	19E5F01	ALF001W	06/03/1910:00	06/04/19

EMAX QUALITY CONTROL DATA
LAB CONTROL SAMPLE ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO. : 19F012
METHOD : METHOD 2320B

MATRIX : WATER % MOISTURE: NA

DILUTION FACTOR:	1	1	1
SAMPLE ID :	MBLK1W	LCS1W	LCD1W
LAB SAMPLE ID :	ALF001WB	ALF001WL	ALF001WC
LAB FILE ID :	19E5F0103	19E5F0104	19E5F0105
DATE EXTRACTED :	NA	NA	NA
DATE ANALYZED :	06/06/1914:07	06/06/1914:14	06/06/1914:21
PREP BATCH :	ALF001W	ALF001W	ALF001W
CALIBRATION REF:	19E5F01	19E5F01	19E5F01

ACCESSION:

PARAMETER	MB RESULT (mg/L)	SPIKE AMT (mg/L)	BS RESULT (mg/L)	BS REC (%)	SPIKE AMT (mg/L)	BSD RESULT (mg/L)	BSD REC (%)	RPD (%)	QC LIMIT (%)	MAX RPD (%)
TOTAL ALKALINITY	ND	80.7	79.9	99	80.7	82.1	102	3	80-120	20

EMAX QUALITY CONTROL DATA
SAMPLE DUPLICATE ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO. : 19F012
METHOD : METHOD 2320B

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MATRIX	: WATER	
DILUTION FACTOR	: 1	1
SAMPLE ID	: 190104	190104DUP
LAB SAMPLE ID	: F012-01	F012-01D
LAB FILE ID	: 19E5F0114	19E5F0115
DATE PREPARED	: NA	NA
DATE ANALYZED	: 06/06/1915:20	06/06/1915:26
PREP BATCH	: ALF001W	ALF001W
CALIBRATION REF	: 19E5F011	19E5F011

ACCESSION:

PARAMETER	PARENT RESULT (mg/L)	DUP RESULT (mg/L)	RPD (%)	MAX RPD (%)
TOTAL ALKALINITY	32.5	32.2	0.9	20

CASE NARRATIVE

Client : PUNA GEOTHERMAL VENTURE

Project: SEMI-ANNUAL GROUNDWATER SAMPLING

SDG : 19F012

METHOD 2540C
TOTAL DISSOLVED SOLIDS

A total of two(2) water samples were received on 06/04/19 to be analyzed for Total Dissolved Solids in accordance with Method 2540C and project specific requirements.

Holding Time
Samples were analyzed within the prescribed holding time.

Calibration
Balance calibration verifications were carried out on a frequency specified by the method. All calibration requirements were within acceptance criteria.

Method Blank
Method blank was prepared and analyzed at the frequency required by the project. For this SDG, one(1) method blank was analyzed. TDS was not detected in TDF002WB. Refer to sample result summary form for details.

Lab Control Sample
Lab control sample was prepared and analyzed at a frequency required by the project. For this SDG, one(1) LCS was analyzed. Percent recovery for TDS was within LCS QC limits in TDF002WL. Refer to LCS summary form for details.

Matrix QC Sample
No matrix QC sample was provided on this SDG.

Sample Analysis
Samples were analyzed according to prescribed analytical procedures. Results were evaluated in accordance to project requirements. For this SDG, all quality control requirements were met.

METHOD 2540C
TOTAL DISSOLVED SOLIDS

Client	: PUNA GEOTHERMAL VENTURE	Matrix	: WATER
Project	: SEMI-ANNUAL GROUNDWATER SAMPLING	InstrumentID	: 402426
Batch No.	: 19F012		

CLIENT SAMPLE ID	EMAX SAMPLE ID	RESULTS (mg/L)	DFxPREP FACTOR	MOIST (%)	RL (mg/L)	MDL (mg/L)	ANALYSIS DATETIME	PREPARATION DATETIME	DATA FILE ID	CAL REF	PREP BATCH	COLLECTION DATETIME	RECEIVED DATETIME
MBLK1W	TDF002WB	ND	1	NA	10	10	06/06/1917:11	NA	19TDF00201	19TDF002	TDF002W	NA	NA
LCS1W	TDF002WL	1040	1	NA	10	10	06/06/1917:11	NA	19TDF00202	19TDF002	TDF002W	NA	NA
190104	F012-01	4270	1	NA	10	10	06/06/1917:11	NA	19TDF00203	19TDF002	TDF002W	06/03/1909:00	06/04/19
190107	F012-02	3800	1	NA	10	10	06/06/1917:11	NA	19TDF00204	19TDF002	TDF002W	06/03/1910:00	06/04/19

EMAX QUALITY CONTROL DATA
LCS ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO. : 19F012
METHOD : 2540C

MATRIX	: WATER	
DILUTION FACTOR:	1	1
SAMPLE ID	: MBLK1W	LCS1W
LAB SAMPLE ID	: TDF002WB	TDF002WL
LAB FILE ID	: 19TDF00201	19TDF00202
DATE PREPARED	: NA	NA
DATE ANALYZED	: 06/06/1917:11	06/06/1917:11
PREP BATCH	: TDF002W	TDF002W
CALIBRATION REF:	19TDF002	19TDF002

ACCESSION:

PARAMETER	MB RESULT (mg/L)	SPIKE AMT (mg/L)	BS RESULT (mg/L)	BS REC (%)	QC LIMIT (%)
TDS	ND	1000	1040	104	80-120

CASE NARRATIVE

Client : PUNA GEOTHERMAL VENTURE

Project: SEMI-ANNUAL GROUNDWATER SAMPLING

SDG : 19F012

METHOD 2540D
TOTAL SUSPENDED SOLIDS

A total of two(2) water samples were received on 06/04/19 to be analyzed for Total Suspended Solids in accordance with Method 2540D and project specific requirements.

Holding Time
Samples were analyzed within the prescribed holding time.

Calibration
Balance calibration verifications were carried out on a frequency specified by the method. All calibration requirements were within acceptance criteria.

Method Blank
Method blank was prepared and analyzed at the frequency required by the project. For this SDG, one(1) method blank was analyzed. TSS was not detected in SSF003WB. Refer to sample result summary form for details.

Lab Control Sample
Lab control sample was prepared and analyzed at a frequency required by the project. For this SDG, one(1) set of LCS/LCD was analyzed. SSF003WL/SSF003WC were within LCS limits. Refer to LCS summary form for details.

Matrix QC Sample
No matrix QC sample was provided on this SDG.

Sample Analysis
Samples were analyzed according to prescribed analytical procedures. Results were evaluated in accordance to project requirements. For this SDG, all quality control requirements were met.

METHOD 2540D
TOTAL SUSPENDED SOLIDS

Client : PUNA GEOTHERMAL VENTURE
Project : SEMI-ANNUAL GROUNDWATER SAMPLING
Batch No. : 19F012

Matrix : WATER
InstrumentID : 402426

CLIENT SAMPLE ID	EMAX SAMPLE ID	RESULTS (mg/L)	DFxPREP FACTOR	MOIST (%)	RL (mg/L)	MDL (mg/L)	ANALYSIS DATETIME	PREPARATION DATETIME	DATA FILE ID	CAL REF	PREP BATCH	COLLECTION DATETIME	RECEIVED DATETIME
MBLK1W	SSF003WB	ND	1	NA	10	10	06/07/1911:35	NA	19SSF00301	19SSF003	SSF003W	NA	NA
LCS1W	SSF003WL	97.5	1	NA	10	10	06/07/1911:35	NA	19SSF00302	19SSF003	SSF003W	NA	NA
LCD1W	SSF003WC	95.0	1	NA	10	10	06/07/1911:35	NA	19SSF00303	19SSF003	SSF003W	NA	NA
190104	F012-01	ND	1	NA	10	10	06/07/1911:35	NA	19SSF00304	19SSF003	SSF003W	06/03/1909:00	06/04/19
190107	F012-02	ND	1	NA	10	10	06/07/1911:35	NA	19SSF00305	19SSF003	SSF003W	06/03/1910:00	06/04/19

EMAX QUALITY CONTROL DATA
LAB CONTROL SAMPLE ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO. : 19F012
METHOD : 2540D

MATRIX	: WATER		% MOISTURE: NA
DILUTION FACTOR:	1	1	1
SAMPLE ID	: MBLK1W	LCS1W	LCD1W
LAB SAMPLE ID	: SSF003WB	SSF003WL	SSF003WC
LAB FILE ID	: 19SSF00301	19SSF00302	19SSF00303
DATE EXTRACTED	: NA	NA	NA
DATE ANALYZED	: 06/07/1911:35	06/07/1911:35	06/07/1911:35
PREP BATCH	: SSF003W	SSF003W	SSF003W
CALIBRATION REF:	19SSF003	19SSF003	19SSF003

ACCESSION:

PARAMETER	MB RESULT (mg/L)	SPIKE AMT (mg/L)	BS RESULT (mg/L)	BS REC (%)	SPIKE AMT (mg/L)	BSD RESULT (mg/L)	BSD REC (%)	RPD (%)	QC LIMIT (%)	MAX RPD (%)
TSS	ND	94.3	97.5	103	94.3	95	101	3	80-120	20

CASE NARRATIVE

Client : PUNA GEOTHERMAL VENTURE

Project: SEMI-ANNUAL GROUNDWATER SAMPLING

SDG : 19F012

METHOD 4500-SIO2C
SILICA

A total of two(2) water samples were received on 06/04/19 to be analyzed for Silica in accordance with Method 4500-SIO2C and project specific requirements.

Holding Time
Samples were analyzed within the prescribed holding time.

Calibration
Calibration was performed as prescribed by the method and was verified using a secondary source (ICV). All calibration requirements were within acceptance criteria.

Method Blank
Method blank was prepared and analyzed at the frequency required by the project. For this SDG, one(1) method blank was analyzed. Silica was not detected in SIF001WB. Refer to sample result summary form for details.

Lab Control Sample
Lab control sample was prepared and analyzed at a frequency required by the project. For this SDG, one(1) set of LCS/LCD was analyzed. SIF001WL/SIF001WC were within LCS limits. Refer to LCS summary form for details.

Matrix QC Sample
Matrix spike sample was prepared and analyzed at a frequency required by the project. For this SDG, one(1) set of MS/MSD was analyzed. Silica was within MS QC limits in F012-02IM/F012-02IS. Sample duplicate was analyzed and RPD was within expected value. Refer to Matrix QC summary forms for details.

Sample Analysis
Samples were analyzed according to prescribed analytical procedures. Results were evaluated in accordance to project requirements. For this SDG, all quality control requirements were met.

METHOD 4500-SIO2C
SILICA

Client	: PUNA GEOTHERMAL VENTURE	Matrix	: WATER
Project	: SEMI-ANNUAL GROUNDWATER SAMPLING	InstrumentID	: 70
Batch No.	: 19F012		

CLIENT SAMPLE ID	EMAX SAMPLE ID	RESULTS (mg/L)	DFxPREP FACTOR	MOIST (%)	RL (mg/L)	MDL (mg/L)	ANALYSIS DATETIME	PREPARATION DATETIME	DATA FILE ID	CAL REF	PREP BATCH	COLLECTION DATETIME	RECEIVED DATETIME
MBLK1W	SIF001WB	ND	1	NA	2	0.5	06/10/1918:33	NA	19SIF00110	19SIF001	SIF001W	NA	NA
LCS1W	SIF001WL	15.1	1	NA	2	0.5	06/10/1918:33	NA	19SIF00111	19SIF001	SIF001W	NA	NA
LCD1W	SIF001WC	15.3	1	NA	2	0.5	06/10/1918:33	NA	19SIF00112	19SIF001	SIF001W	NA	NA
190104	F012-01I	143	10	NA	20	5	06/10/1918:46	NA	19SIF00120	19SIF001	SIF001W	06/03/1909:00	06/04/19
190107	F012-02I	144	20	NA	40	10	06/10/1918:47	NA	19SIF00121	19SIF001	SIF001W	06/03/1910:00	06/04/19
190107DUP	F012-02ID	146	20	NA	40	10	06/10/1918:48	NA	19SIF00122	19SIF001	SIF001W	06/03/1910:00	06/04/19
190107MS	F012-02IM	454	20	NA	40	10	06/10/1918:48	NA	19SIF00123	19SIF001	SIF001W	06/03/1910:00	06/04/19
190107MSD	F012-02IS	449	20	NA	40	10	06/10/1918:48	NA	19SIF00124	19SIF001	SIF001W	06/03/1910:00	06/04/19

EMAX QUALITY CONTROL DATA
LAB CONTROL SAMPLE ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO. : 19F012
METHOD : 4500-SIO2C

MATRIX	: WATER		% MOISTURE:NA
DILUTION FACTOR:	1	1	1
SAMPLE ID	: MBLK1W	LCS1W	LCD1W
LAB SAMPLE ID	: SIF001WB	SIF001WL	SIF001WC
LAB FILE ID	: 19SIF00110	19SIF00111	19SIF00112
DATE PREPARED	: NA	NA	NA
DATE ANALYZED	: 06/10/1918:33	06/10/1918:33	06/10/1918:33
PREP BATCH	: SIF001W	SIF001W	SIF001W
CALIBRATION REF:	19SIF001	19SIF001	19SIF001

ACCESSION:

PARAMETERS	MBResult (mg/L)	SpikeAmt (mg/L)	LCSResult (mg/L)	LCSRec (%)	SpikeAmt (mg/L)	LCDResult (mg/L)	LCDRec (%)	RPD (%)	QCLimit (%)	MaxRPD (%)
SILICA	ND	15.0	15.1	101	15.0	15.3	102	1	80-120	20

MB: Method Blank sample LCS: Lab Control Sample LCD: Lab Control Sample Duplicate

EMAX QUALITY CONTROL DATA
MS/MSD ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO. : 19F012
METHOD : 4500-SIO2C

MATRIX	: WATER		% MOISTURE:NA
DILUTION FACTOR:	20	20	20
SAMPLE ID	: 190107	190107MS	190107MSD
LAB SAMPLE ID	: F012-02I	F012-02IM	F012-02IS
LAB FILE ID	: 19SIF00121	19SIF00123	19SIF00124
DATE PREPARED	: NA	NA	NA
DATE ANALYZED	: 06/10/1918:47	06/10/1918:48	06/10/1918:48
PREP BATCH	: SIF001W	SIF001W	SIF001W
CALIBRATION REF:	19SIF001	19SIF001	19SIF001

ACCESSION:

PARAMETERS	PSResult (mg/L)	SpikeAmt (mg/L)	MSResult (mg/L)	MSRec (%)	SpikeAmt (mg/L)	MSDResult (mg/L)	MSDRec (%)	RPD (%)	QCLimit (%)	MaxRPD (%)
SILICA	144	300	454	103	300	449	102	1	75-125	20

PS: Parent Sample MS: Matrix Spike MSD: Matrix Spike Duplicate

EMAX QUALITY CONTROL DATA
SAMPLE DUPLICATE ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO. : 19F012
METHOD : 4500-SIO2C

MATRIX	: WATER	
DILUTION FACTOR	: 20	20
SAMPLE ID	: 190107	190107DUP
LAB SAMPLE ID	: F012-02I	F012-02ID
LAB FILE ID	: 19SIF00121	19SIF00122
DATE PREPARED	: NA	NA
DATE ANALYZED	: 06/10/1918:47	06/10/1918:48
PREP BATCH	: SIF001W	SIF001W
CALIBRATION REF	: 19SIF001	19SIF001

ACCESSION:

PARAMETER	PSResult (mg/L)	DUPResult (mg/L)	RPD (%)	QCLimit (%)
SILICA	144	146	1	20

PS: Parent Sample DUP: Sample Duplicate

CASE NARRATIVE

Client : PUNA GEOTHERMAL VENTURE

Project: SEMI-ANNUAL GROUNDWATER SAMPLING

SDG : 19F012

SW846 CHAPTER 7.3
REACTIVE CYANIDE

A total of two(2) water samples were received on 06/04/19 to be analyzed for Reactive Cyanide in accordance with SW846 Chapter 7.3 and project specific requirements.

Holding Time
Samples were analyzed within the prescribed holding time.

Calibration
Calibration was performed as prescribed by the method and was verified using a secondary source (ICV). All calibration requirements were within acceptance criteria.

Method Blank
Method blank was prepared and analyzed at the frequency required by the project. For this SDG, one(1) method blank was analyzed. Reactive Cyanide was not detected in RCF001WB. Refer to sample result summary form for details.

Lab Control Sample
Lab control sample was prepared and analyzed at a frequency required by the project. For this SDG, one(1) set of LCS/LCD was analyzed. RCF001WL/RCF001WC were within LCS limits. Refer to LCS summary form for details.

Matrix QC Sample
Sample duplicate was analyzed and RPD was within expected value.

Sample Analysis
Samples were analyzed according to prescribed analytical procedures. Results were evaluated in accordance to project requirements. For this SDG, all quality control requirements were met.

METHOD CHAPTER 7.3/SW846
REACTIVE CYANIDE

Client : PUNA GEOTHERMAL VENTURE
Project : SEMI-ANNUAL GROUNDWATER SAMPLING
Batch No. : 19F012

Matrix : WATER
InstrumentID : 70

CLIENT SAMPLE ID	EMAX SAMPLE ID	RESULTS (mg/L)	DFxPREP FACTOR	MOIST (%)	RL (mg/L)	MDL (mg/L)	ANALYSIS DATETIME	PREPARATION DATETIME	DATA FILE ID	CAL REF	PREP BATCH	COLLECTION DATETIME	RECEIVED DATETIME
MBLK1W	RCF001WB	ND	1	NA	0.02	0.015	06/18/1912:45	06/06/1913:42	19RCF00110	19RCF001	RCF001W	NA	NA
LCS1W	RCF001WL	0.592	1	NA	0.02	0.015	06/18/1912:45	06/06/1913:42	19RCF00111	19RCF001	RCF001W	NA	NA
LCD1W	RCF001WC	0.577	1	NA	0.02	0.015	06/18/1912:45	06/06/1913:42	19RCF00112	19RCF001	RCF001W	NA	NA
190104	F012-01	0.0186J	1	NA	0.02	0.015	06/18/1912:45	06/06/1913:42	19RCF00113	19RCF001	RCF001W	06/03/1909:00	06/04/19
190107	F012-02	ND	1	NA	0.02	0.015	06/18/1912:46	06/06/1913:42	19RCF00114	19RCF001	RCF001W	06/03/1910:00	06/04/19
190107DUP	F012-02D	ND	1	NA	0.02	0.015	06/18/1912:46	06/06/1913:42	19RCF00115	19RCF001	RCF001W	06/03/1910:00	06/04/19

EMAX QUALITY CONTROL DATA
LAB CONTROL SAMPLE ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO. : 19F012
METHOD : CHAPTER 7.3/SW846

MATRIX	: WATER		% MOISTURE:NA
DILUTION FACTOR:	1	1	1
SAMPLE ID	: MBLK1W	LCS1W	LCD1W
LAB SAMPLE ID	: RCF001WB	RCF001WL	RCF001WC
LAB FILE ID	: 19RCF00110	19RCF00111	19RCF00112
DATE PREPARED	: 06/06/1913:42	06/06/1913:42	06/06/1913:42
DATE ANALYZED	: 06/18/1912:45	06/18/1912:45	06/18/1912:45
PREP BATCH	: RCF001W	RCF001W	RCF001W
CALIBRATION REF:	19RCF001	19RCF001	19RCF001

ACCESSION:

PARAMETERS	MBResult (mg/L)	SpikeAmt (mg/L)	LCSResult (mg/L)	LCSRec (%)	SpikeAmt (mg/L)	LCDResult (mg/L)	LCDRec (%)	RPD (%)	QCLimit (%)	MaxRPD (%)
Reactive Cyanide	ND	2.52	0.592	23	2.52	0.577	23	3	5-120	20

MB: Method Blank sample LCS: Lab Control Sample LCD: Lab Control Sample Duplicate

EMAX QUALITY CONTROL DATA
SAMPLE DUPLICATE ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO. : 19F012
METHOD : CHAPTER 7.3/SW846

MATRIX	: WATER	
DILUTION FACTOR:	1	1
SAMPLE ID	: 190107	190107DUP
LAB SAMPLE ID	: F012-02	F012-02D
LAB FILE ID	: 19RCF00114	19RCF00115
DATE PREPARED	: 06/06/1913:42	06/06/1913:42
DATE ANALYZED	: 06/18/1912:46	06/18/1912:46
PREP BATCH	: RCF001W	RCF001W
CALIBRATION REF:	19RCF001	19RCF001

ACCESSION:

PARAMETER	PSResult (mg/L)	DUPResult (mg/L)	RPD (%)	QCLimit (%)
Reactive Cyanide	ND	ND	0	20

PS: Parent Sample DUP: Sample Duplicate

CASE NARRATIVE

Client : PUNA GEOTHERMAL VENTURE

Project: SEMI-ANNUAL GROUNDWATER SAMPLING

SDG : 19F012

SW846 CHAPTER 7.3
REACTIVE SULFIDE

A total of two(2) water samples were received on 06/04/19 to be analyzed for Reactive Sulfide in accordance with SW846 Chapter 7.3 and project specific requirements.

Holding Time
Samples were analyzed within the prescribed holding time.

Method Blank
Method blank was prepared and analyzed at the frequency required by the project. For this SDG, one(1) method blank was analyzed. Reactive Sulfide was not detected in RSF001WB. Refer to sample result summary form for details.

Lab Control Sample
Lab control sample was prepared and analyzed at a frequency required by the project. For this SDG, one(1) set of LCS/LCD was analyzed. RSF001WL/RSF001WC were within LCS limits. Refer to LCS summary form for details.

Matrix QC Sample
Sample duplicate was analyzed and RPD was within expected value.

Sample Analysis
Samples were analyzed according to prescribed analytical procedures. Results were evaluated in accordance to project requirements. For this SDG, all quality control requirements were met.

METHOD CHAPTER 7.3/SW846
REACTIVE SULFIDE

Client : PUNA GEOTHERMAL VENTURE
Project : SEMI-ANNUAL GROUNDWATER SAMPLING
Batch No. : 19F012

Matrix : WATER
InstrumentID : NA

CLIENT SAMPLE ID	EMAX SAMPLE ID	RESULTS (mg/L)	PREP. FACTOR	MOIST (%)	RL (mg/L)	MDL (mg/L)	ANALYSIS DATETIME	PREPARATION DATETIME	DATA FILE ID	CAL REF	PREP BATCH	COLLECTION DATETIME	RECEIVED DATETIME
MBLK1W	RSF001WB	ND	1.00	NA	.5	.5	06/07/1918:42	06/06/1913:42	19RSF00101	19RSF001	RSF001W	NA	NA
LCS1W	RSF001WL	3.68	1.00	NA	.5	.5	06/07/1918:44	06/06/1913:42	19RSF00102	19RSF001	RSF001W	NA	NA
LCD1W	RSF001WC	3.68	1.00	NA	.5	.5	06/07/1918:46	06/06/1913:42	19RSF00103	19RSF001	RSF001W	NA	NA
190104	F012-01	ND	1.00	NA	.5	.5	06/07/1918:48	06/06/1913:42	19RSF00104	19RSF001	RSF001W	06/03/1909:00	06/04/19
190107	F012-02	ND	1.00	NA	.5	.5	06/07/1918:50	06/06/1913:42	19RSF00105	19RSF001	RSF001W	06/03/1910:00	06/04/19
190107DUP	F012-02D	ND	1.00	NA	.5	.5	06/07/1918:52	06/06/1913:42	19RSF00106	19RSF001	RSF001W	06/03/1910:00	06/04/19

EMAX QUALITY CONTROL DATA
LAB CONTROL SAMPLE ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO. : 19F012
METHOD : METHOD CHAPTER 7.3/SW846

===

MATRIX	: WATER			% MOISTURE: NA
DILUTION FACTOR:	1	1	1	
SAMPLE ID	: MBLK1W	LCS1W	LCD1W	
LAB SAMPLE ID	: RSF001WB	RSF001WL	RSF001WC	
LAB FILE ID	: 19RSF00101	19RSF00102	19RSF00103	
DATE EXTRACTED	: NA	NA	NA	
DATE ANALYZED	: 06/07/1918:42	06/07/1918:44	06/07/1918:46	
PREP BATCH	: RSF001W	RSF001W	RSF001W	
CALIBRATION REF:				

ACCESSION:

PARAMETER	MB RESULT (mg/L)	SPIKE AMT (mg/L)	BS RESULT (mg/L)	BS REC (%)	SPIKE AMT (mg/L)	BSD RESULT (mg/L)	BSD REC (%)	RPD (%)	QC LIMIT (%)	MAX RPD (%)
Reactive Sulfide	ND	3.98	3.68	92	3.98	3.68	92	0	30-120	20

EMAX QUALITY CONTROL DATA
SAMPLE DUPLICATE ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO. : 19F012
METHOD : METHOD CHAPTER 7.3/SW846

==

MATRIX	: WATER	
DILUTION FACTOR	: 1.00	1.00
SAMPLE ID	: 190107	190107DUP
LAB SAMPLE ID	: F012-02	F012-02D
LAB FILE ID	: 19RSF00105	19RSF00106
DATE PREPARED	: 06/06/1913:42	06/06/1913:42
DATE ANALYZED	: 06/07/1918:50	06/07/1918:52
PREP BATCH	: RSF001W	RSF001W
CALIBRATION REF	: 19RSF001	19RSF001

ACCESSION:

PARAMETER	PARENT RESULT (mg/L)	DUP RESULT (mg/L)	RPD (%)	MAX RPD (%)
Reactive Sulfide	ND	ND	0	20

CASE NARRATIVE

Client : PUNA GEOTHERMAL VENTURE

Project: SEMI-ANNUAL GROUNDWATER SAMPLING

SDG : 19F012

METHOD 9040C
PH

A total of two(2) water samples were received on 06/04/19 to be analyzed for pH in accordance with Method 9040C and project specific requirements.

Holding Time
Samples were analyzed within the prescribed holding time.

Calibration
pH meter was calibrated per instrument operating manual instruction. Calibration was verified using a secondary source (ICV). Continuing calibration (CCV) verifications were carried out on a frequency specified by the project. All calibration requirements were within acceptance criteria.

Matrix QC Sample
Sample duplicate was analyzed and RPD was within expected value.

Sample Analysis
Samples were analyzed according to prescribed analytical procedures. Results were evaluated in accordance to project requirements. For this SDG, all quality control requirements were met.

METHOD 9040C
PH

Client	: PUNA GEOTHERMAL VENTURE	Matrix	: WATER
Project	: SEMI-ANNUAL GROUNDWATER SAMPLING	InstrumentID	: 53
Batch No.	: 19F012		

CLIENT SAMPLE ID	EMAX SAMPLE ID	RESULTS (pH Unit)	DFxPREP FACTOR	MOIST (%)	RL (pH Unit)	MDL (pH Unit)	ANALYSIS DATETIME	PREPARATION DATETIME	DATA FILE ID	CAL REF	PREP BATCH	COLLECTION DATETIME	RECEIVED DATETIME
190104	F012-01	6.93	1	NA	0.1	0.1	06/04/1915:11	NA	19PHF00101	19PHF001	PHF001W	06/03/1909:00	06/04/19
190104DUP	F012-01D	6.95	1	NA	0.1	0.1	06/04/1915:15	NA	19PHF00102	19PHF001	PHF001W	06/03/1909:00	06/04/19
190107	F012-02	6.93	1	NA	0.1	0.1	06/04/1915:18	NA	19PHF00103	19PHF001	PHF001W	06/03/1910:00	06/04/19

EMAX QUALITY CONTROL DATA
SAMPLE DUPLICATE ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : SEMI-ANNUAL GROUNDWATER SAMPLING
BATCH NO. : 19F012
METHOD : 9040C

==

MATRIX	: WATER	
DILUTION FACTOR	: 1	1
SAMPLE ID	: 190104	190104DUP
LAB SAMPLE ID	: F012-01	F012-01D
LAB FILE ID	: 19PHF00101	19PHF00102
DATE PREPARED	: NA	NA
DATE ANALYZED	: 06/04/1915:11	06/04/1915:15
PREP BATCH	: PHF001W	PHF001W
CALIBRATION REF	: 19PHF001	19PHF001

ACCESSION:

PARAMETER	ParentResult (pH Unit)	Dup_Result (pH Unit)	Difference (pH Unit)	Max Diff. (+/- pH Unit)
PH	6.93	6.95	.02	0.1

LABORATORY REPORT FOR

PUNA GEOTHERMAL VENTURE

SEMI-ANNUAL GROUNDWATER SAMPLING

TOTAL SULFUR BY ICPMS

SDG#: 19F012

element

9240 Santa Fe Springs Road
Santa Fe Springs, CA
90670 USA

P: 1 562 948 2225
F: 1 562 948 5850
info.santafesprings@element.com
element.com

Laboratory Report

June 20, 2019

EMAX Laboratories Inc
1835 W 205th St
Torrance, CA 90501-1510

Attn: Raman Singh

Element Job No: 231777
Purchase Order: COD - CC
Project Name: Puna Geothermal Venture Groundwater Sampling Event
Samples Received: 2
Date Received: 06-05-19

Analysis	Page
Sulfur by SOP 7040, Rev 13	2

Michael Shelton
Technical Director

Ishika Lokuge
Senior Chemist

Sulfur by SOP 7040, Rev 13
Inductively Coupled Plasma-Mass Spectrometry

Sample preparation: A sample portion (20 mL) was mixed with 0.4 mL of nitric acid and internal standards to produce a clear solution for ICP-MS analysis.

Parts Per Million (mg/L)

Sample ID	Sulfur
190104	120
190107	120
190107 Duplicate	120
Detection Limit:	3

Date Analyzed: 06-18-19

Quality Control Summary

Sample: 190107

Analyte	Sample Result	Duplicate Result	Sample RPD	Spike Conc	Spike Result	Spike % Rec
Sulfur	122	124	2	100	214	NR

NR - Not reported; sample result exceeds the amount spiked.

Date Analyzed: 06-18-19

Sample: Laboratory Fortified Blank (LFB)

Analyte	Blank Result	Spike Conc	Spike Result	Spike % Rec
Sulfur	ND	100	87	87

Date Analyzed: 06-18-19

CHAIN OF CUSTODY

EMAX Laboratories, Inc.	1835 W. 205th Street, Torrance, CA 90501 Tel # : 310-618-8889 FAX#: 310-618-0818 Email: info@emaxlabs.com	PO NUMBER: SAMPLE STORAGE	EMAX CONTROL NO. 19F012 PROJECT CODE: PGV1901_

	MATRIX CODE	PRESERVATIVE	ANALYSIS REQUIRED	TAT
CLIENT PUNA GEOTHERMAL VENTURE			TOTAL SULFUR ICPMS	
PROJECT GW SAMPLING EVENT	DW=Drinking Water	IC = Ice		☐ Rush __24__hrs.
COORDINATOR	GW=Ground Water	HC = HCl		☐ Rush __48_hrs
TEL FAX EMAIL	WW=Waste Water	HN=HNO3		☐ Rush_72_hrs
SEND FINAL DATA DELIVERABLES TO RAMAN SINGH	SD=Solid Waste SL=Sl	SH=NaO3		☐ 7 days
COMPANY EMAX LABORATORIES	SS=Soil/ Sediment	ST=Na2S2O3		☐ 14 days
ADDRESS 1835W, 205th STREET	WP=Wipes PP=Pure P	ZA=Zinc Acetate		☐ 21 days
TORRANCE CA 90501	AR=Air	HS=H2SO4		STANDARD
EMAX PM RAMAN SINGH 310-618-8899 Ext 119	O=			

LAB	SAMPLE ID CLIENT	LOCATION	SAMPLING DATE	TIME	CONTAINER NO.	SIZE	TYPE	MATRIX CODE	QC	PRESERVATIVE CODE IC	COMMENTS
1	1 190104		6/3/2019	9:00	1	125ML	AMBER	W		X	EMAX ID 19F012-01
2	2 190107		6/3/2019	10:00	1	125ML	AMBER	W		X	EMAX ID 19F012-02
3	06.05.19 AND										
4	Alsohas: F012										
5	1 01 009										
6	2 02 023										
7											
8											

	Cooler #	Temp. (oC)	Sample #s
Instructions PLEASE EMAIL LOGIN AND SUMMARY RESULT TO RAMAN SINGH			
PLEASE SEND ALL DATA DELIVERABLES TO RAMAN SINGH			SUB SAMPLE TO:
			EXOVA, INC.
			9240 SANTA FE SPRINGS ROAD
SAMPLER / COURIER/AIRBILL			SANTA FE SPRINGS, CA 90670. U.S.A

RELINQUISHED BY	Date	Time	RECEIVED BY
[signature]	6/4/19	1640	FedEx
FedEx	06.05.19	10:30AM	Alfred N. [signature] Element

NOTICE: Turn-around-time (TAT) for samples shall not begin untill all discrepancies have been resolved. For samples received and discrepacies resolved after 1500 hrs, TAT shall start at 0800 hrs the next business day. The client is responsible for all cost associted with sample disposal. Samples shall be disposed of as soon as practical (but not prior to fifteen (15) calendar days) after issuance of analytical report unless a different sample disposal schedule is pre-arranged with EMAX. Disposal fee for samples defined by CA Title 22 as non-hazardous shall be $5.00 per sample. EMAX will return hazardous samples to the client at the client's expense unless directed in writing otherwise.

ATTACHMENT F – MAPS AND CROSS SECTIONS OF GEOLOGIC STRUCTURE OF AREA

Refer to Attachment D-1 MAPS

PUNA GEOTHERMAL VENTURE
UIC PERMIT APPLICATION
ATTACHMENT F

NOVEMBER 2019

ORMAT

SAFE HARBOR STATEMENT

Information provided during this presentation may contain statements relating to current expectations, estimates, forecasts and projections about future events that are forward-looking statements as defined in the Private Securities Litigation Reform Act of 1995.

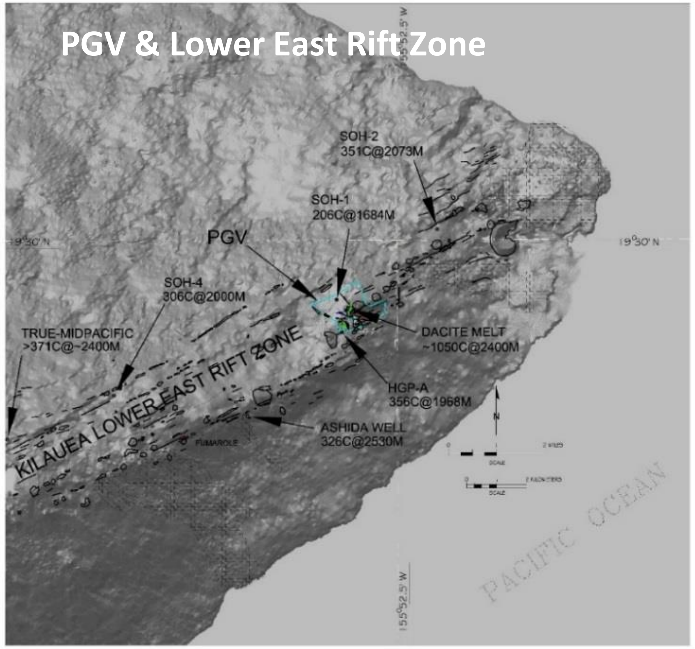
These forward-looking statements generally relate to the company's plans, objectives and expectations for future operations, and are based on management's current estimates and projections of future results or trends. Actual future results may differ materially from those projected as a result of certain risks and uncertainties.

For a discussion of such risks and uncertainties, please see risk factors as described in the Annual Report on Form 10-K filed with the Securities and Exchange Commission on March 16, 2018.

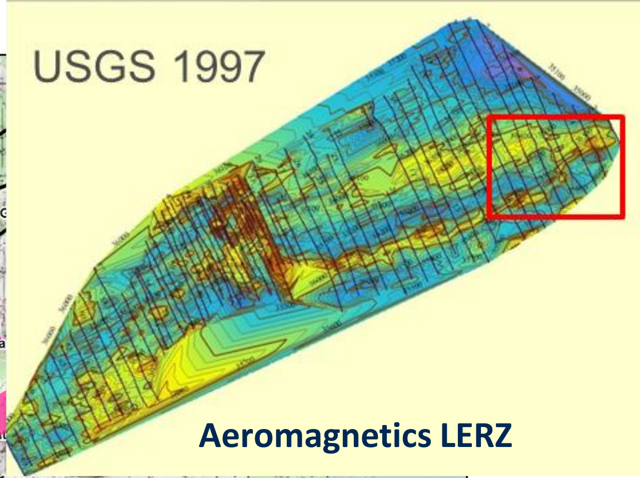
In addition, during this presentation, statements may be made that include a financial measure defined as non-GAAP financial measures by the Securities and Exchange Commission, such as EBITDA and adjusted EBITDA. These measures may be different from non-GAAP financial measures used by other companies. The presentation of this financial information is not intended to be considered in isolation or as a substitute for the financial information prepared and presented in accordance with GAAP.

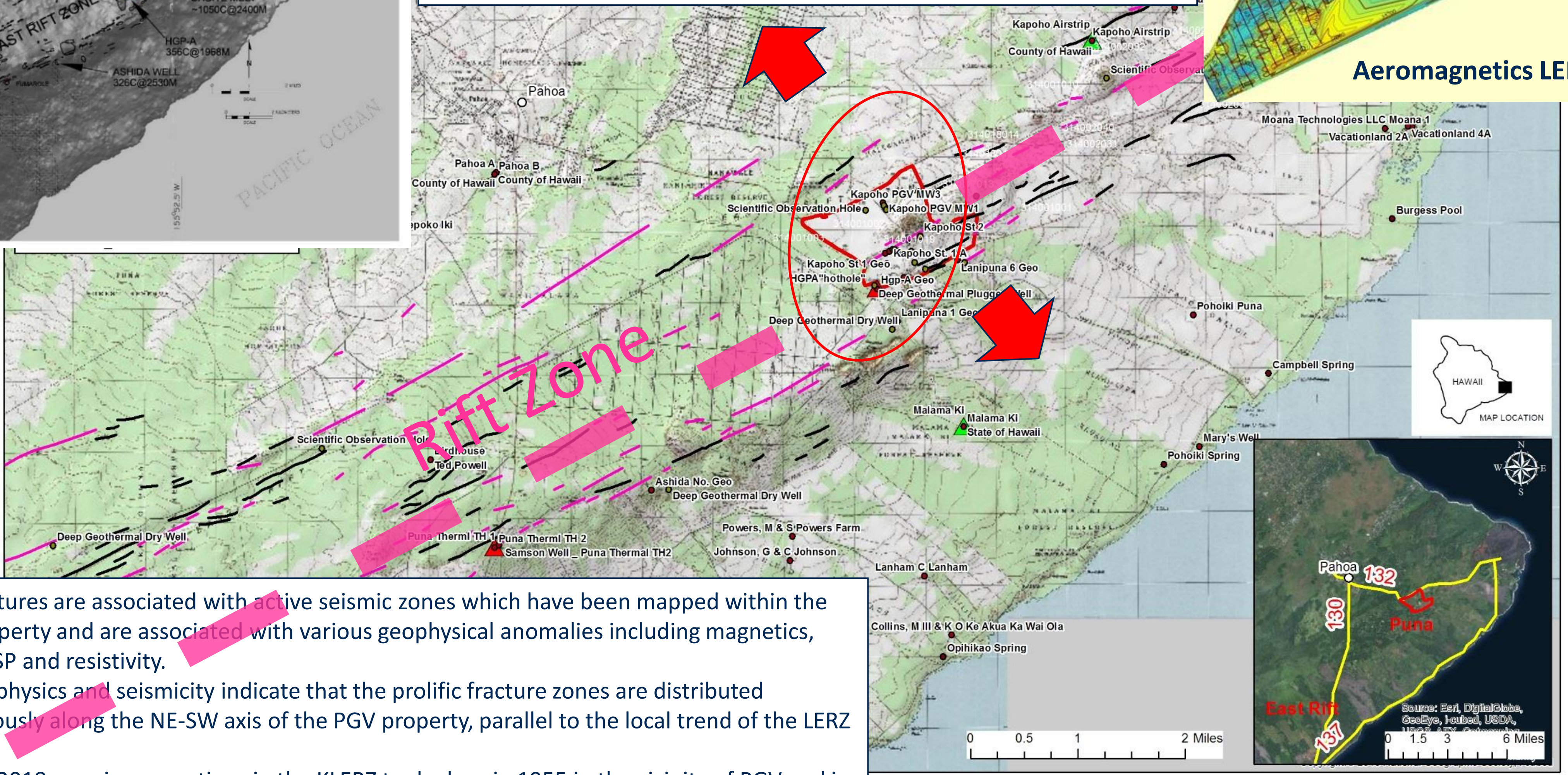
Management of Ormat Technologies believes that EBITDA and adjusted EBITDA may provide meaningful supplemental information regarding liquidity measurement that both management and investors benefit from referring to this non-GAAP financial measures in assessing Ormat Technologies' liquidity, and when planning and forecasting future periods. This non-GAAP financial measures may also facilitate management's internal comparison to the company's historical liquidity.

EBITDA and Adjusted EBITDA are not a measurement of financial performance or liquidity under accounting principles generally accepted in the United States of America and should not be considered as an alternative to cash flow from operating activities or as a measure of liquidity or an alternative to net earnings as indicators of our operating performance or any other measures of performance derived in accordance with accounting principles generally accepted in the United States of America. EBITDA and Adjusted EBITDA are presented because we believe they are frequently used by securities analysts, investors and other interested parties in the evaluation of a company's ability to service and/or incur debt. However, other companies in our industry may calculate EBITDA and Adjusted EBITDA differently than we do.



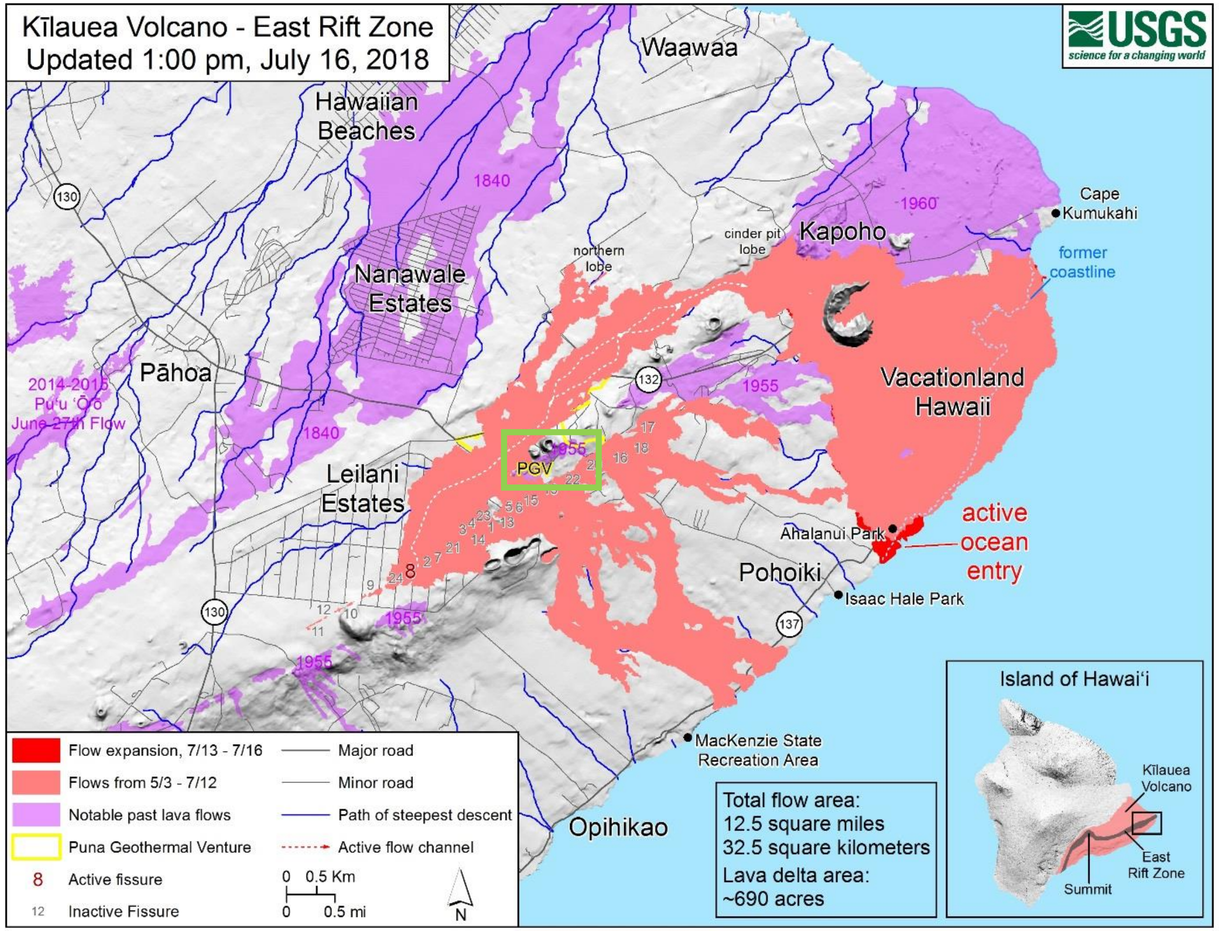
- The reservoir at PGV is hosted in a step over along the axis of the Kilauea Lower East Rift Zone. (KLERZ).
- Subsurface permeability and productivity are controlled by sub-vertical and rift-parallel fractures/faults and dike swarms which are the result of active tectonic dilation across the rift and shallow volcanic activity related to Kilauea.

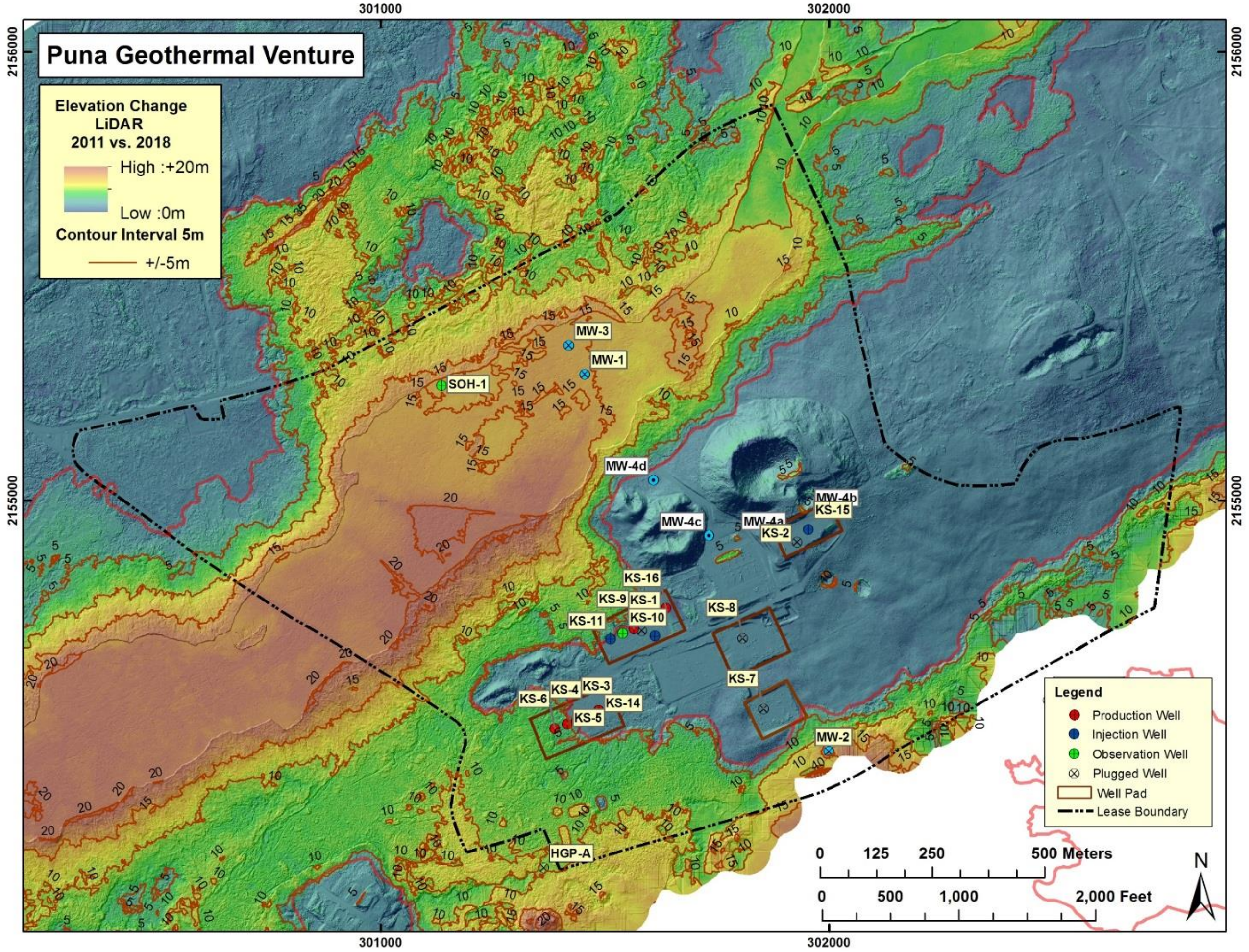


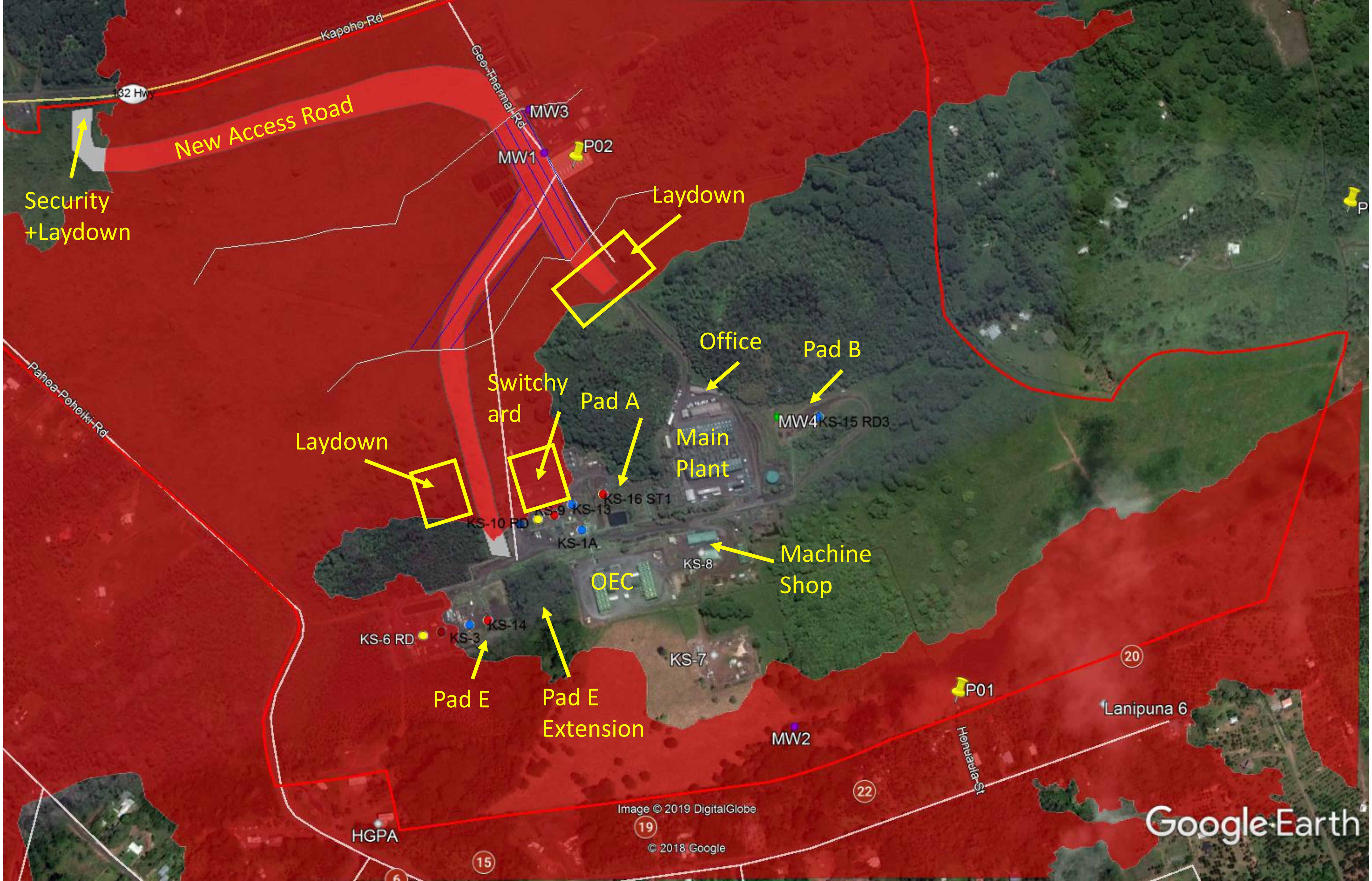


- The fractures are associated with active seismic zones which have been mapped within the PGV property and are associated with various geophysical anomalies including magnetics, gravity, SP and resistivity.
- The geophysics and seismicity indicate that the prolific fracture zones are distributed continuously along the NE-SW axis of the PGV property, parallel to the local trend of the LERZ .
- Prior to 2018, previous eruptions in the KLERZ took place in 1955 in the vicinity of PGV and in 1960 in the Kapoho area six kilometers to the east.

PGV 2018


Kīlauea Volcano - East Rift Zone
Updated 1:00 pm, July 16, 2018
USGS science for a changing world
Waawaa
Hawaiian Beaches
Nanawale Estates
Pāhoa
Leilani Estates
Kapoho
Vacationland Hawaii
Pohoiki
Opihikao
Cape Kumukahi
former coastline
Ahalanui Park
Isaac Hale Park
MacKenzie State Recreation Area
active ocean entry
PGV
2014-2015 Pu'u 'Ō'ō June 27th Flow
Flow expansion, 7/13 - 7/16
Flows from 5/3 - 7/12
Notable past lava flows
Puna Geothermal Venture
Active fissure
Inactive Fissure
Major road
Minor road
Path of steepest descent
Active flow channel
Total flow area:
12.5 square miles
32.5 square kilometers
Lava delta area:
~690 acres
Island of Hawai'i
Kīlauea Volcano
East Rift Zone
Summit


Puna Geothermal Venture
Elevation Change LiDAR 2011 vs. 2018
High :+20m
Low :0m
Contour Interval 5m
+/-5m
Legend
Production Well
Injection Well
Observation Well
Plugged Well
Well Pad
Lease Boundary
0 125 250 500 Meters
0 500 1,000 2,000 Feet



New Access Road
Security
+Laydown
Laydown
Office
Pad B
Switchy
ard
Pad A
Main
Plant
Laydown
Machine
Shop
OEC
Pad E
Pad E
Extension
Kapoho Rd
132 Hwy
Geo-Thermal Rd
Pahoa-Pohoiki-Rd
MW3
MW1
P02
MW4
KS-15 RD3
KS-16 ST1
KS-13
KS-9
KS-10 RD
KS-1A
KS-8
KS-14
KS-3
KS-6 RD
KS-7
MW2
P01
Lanipuna 6
HGPA
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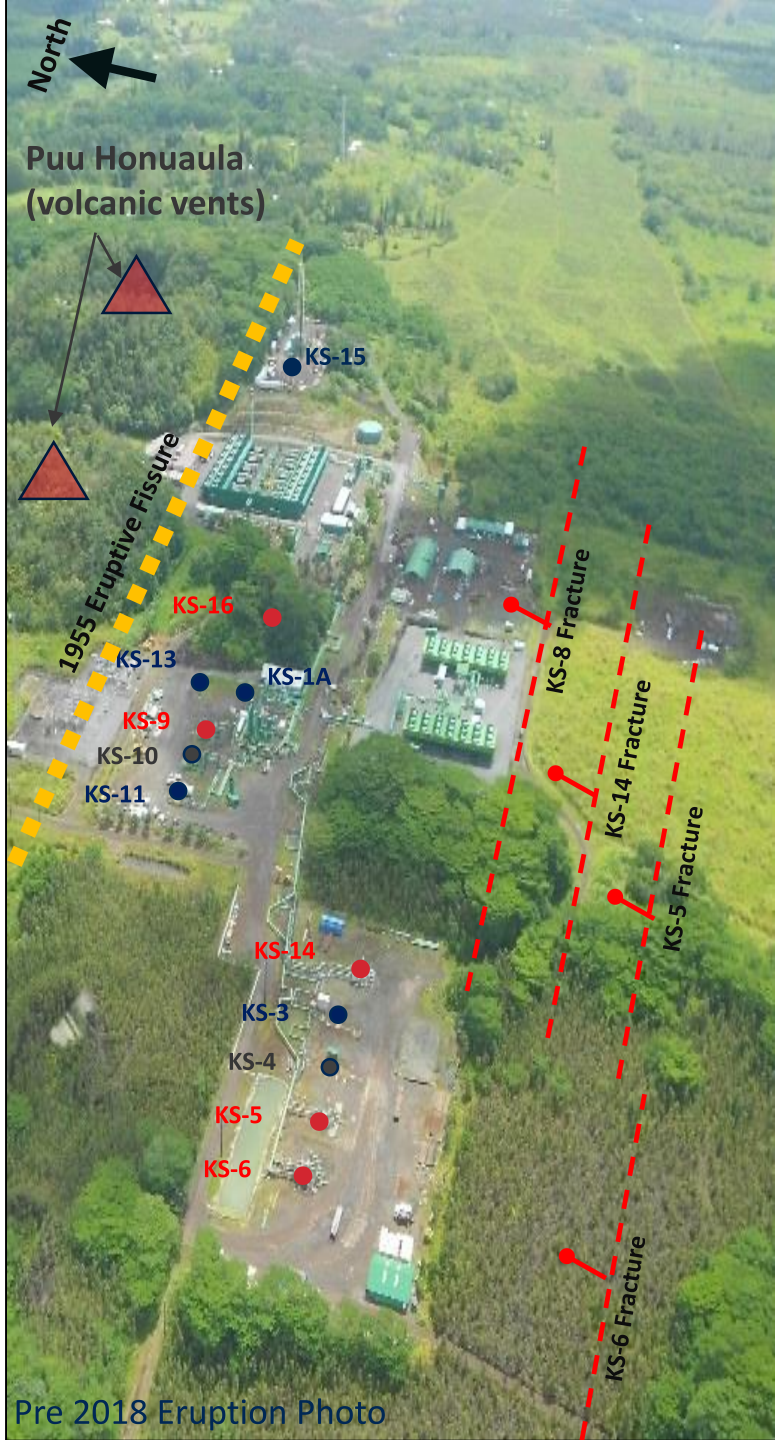
Google Earth

PGV RESOURCE OVERVIEW-PRODUCTION

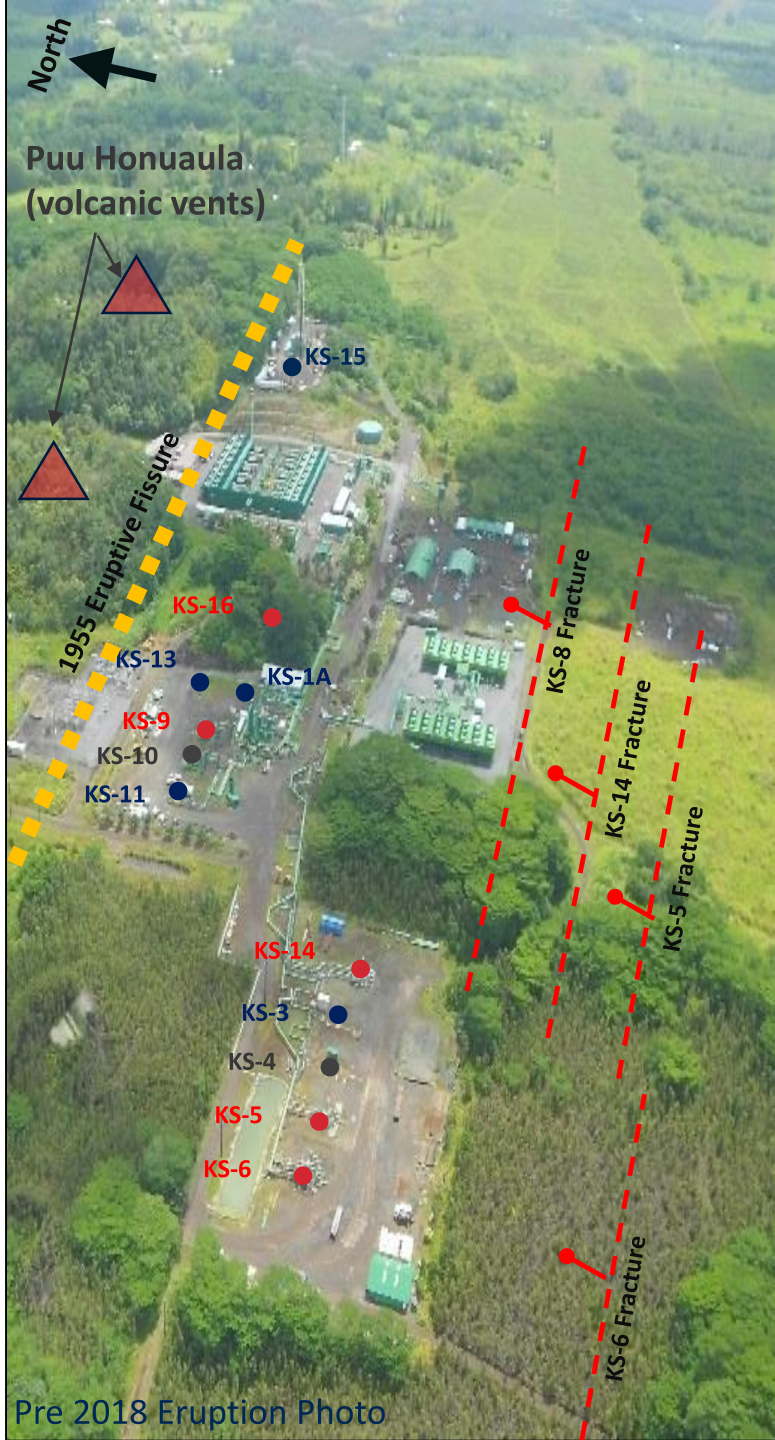
- Associated with large-aperture, steeply dipping fractures.
- Location and attitude of these fractures are well constrained by drilling to be orientated at **N63°E** and dipping at **85°** to the NW.
- Fractures are aligned en-echelon and form a major left-step along the rift axis which results in a localized zone of enhanced dilation.
- Diabasic dikes commonly associated with large aperture fractures (wall rock).
- The main fractures exploited are the **KS-6, KS-5, KS-14 & KS-8.**
- Production depths 4500-6500 ft.
- Wells are two phase steam and brine at temperatures of 600°F (315°C) at a high pressure of 1,430 psi (100 bar). Yield high initial productivity (10-25 MWe).



ORMAT

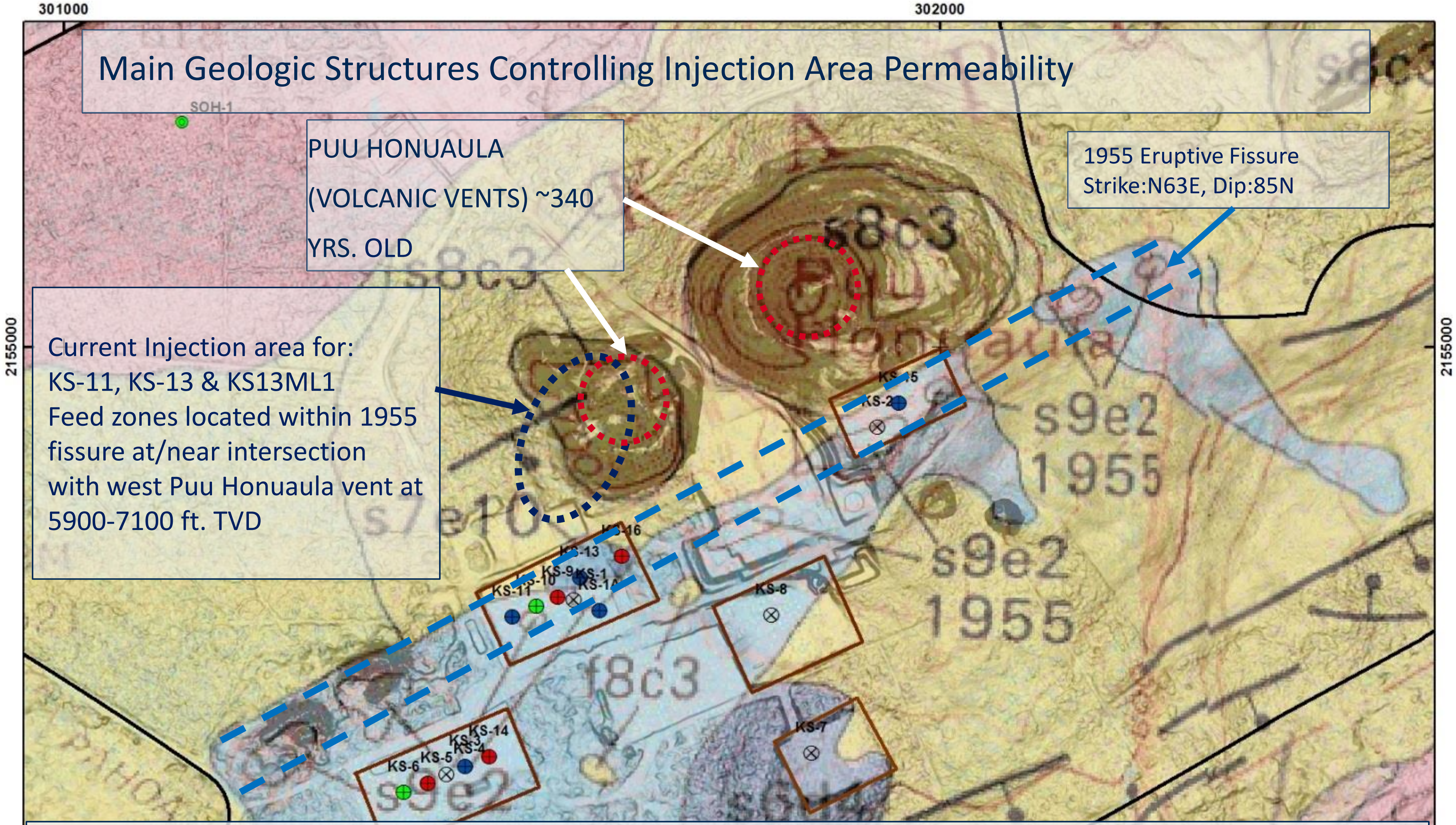
PGV RESOURCE OVERVIEW-INJECTION

- Associated with large-aperture, steeply dipping fractures/fissures and the Puu Honuaula volcanic vents.
- Permeability is also associated with stratigraphic units in submarine basalts consisting primarily of hyaloclastites (glassy basaltic sediments) and pillow basalts. These stratigraphic zones have not proven suitable for production due to their low productivity (2-3 MWe) and higher acidity, but are suitable for injection.
- The main permeable structure exploited is the **1955 Eruptive Fissure**.
- Injection depths 4200-8000 ft. (Majority below 6500 ft.)



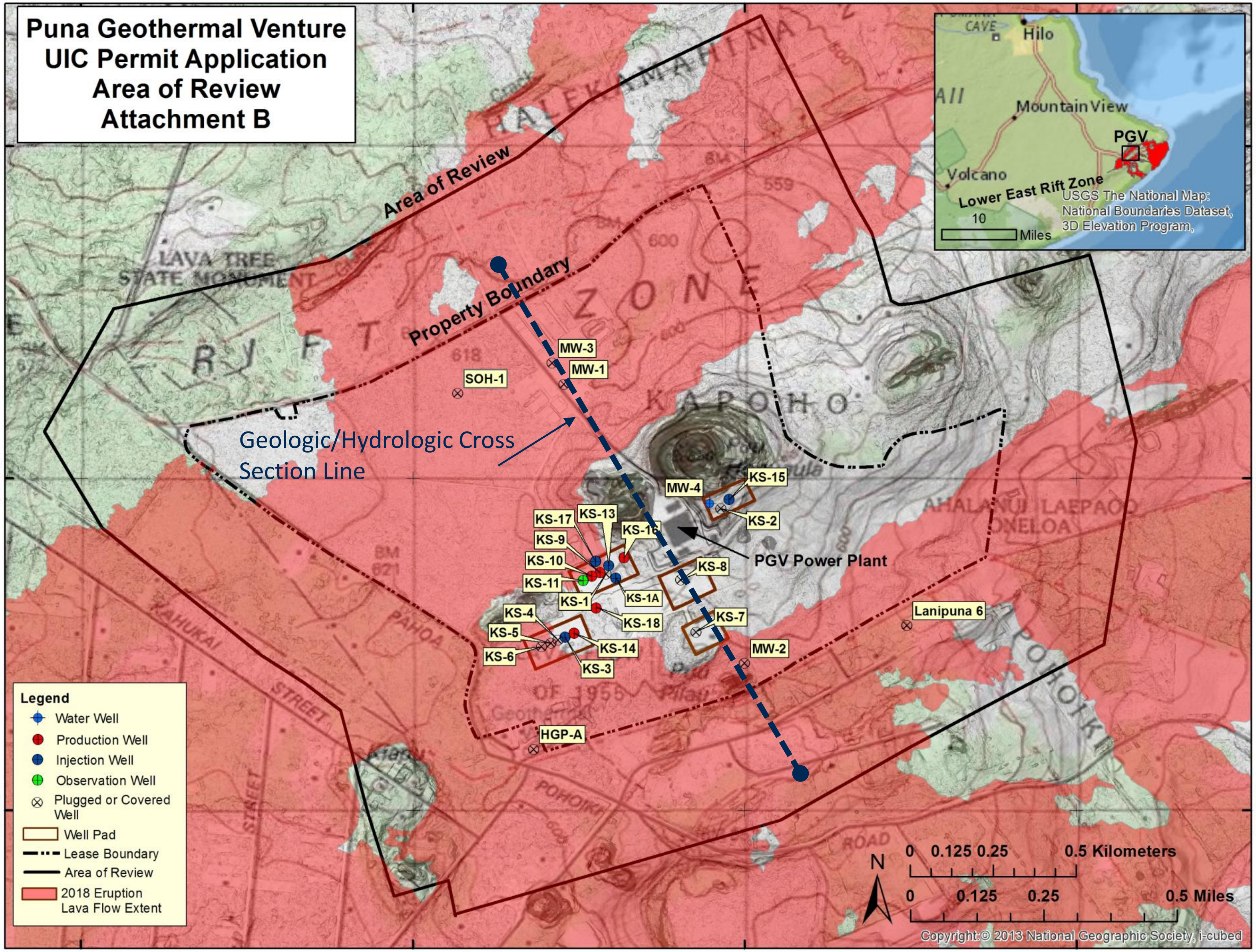
ORMAT

Main Geologic Structures Controlling Injection Area Permeability



- Permeability develops near subvertical structures (fractures, fissures, vents) within the rift zone.
- Basic model: Tectonic dilation of the rift, lithostatic pressure decreases, magma upwells, generates surface lava flows, cinder cones and subsurface dike swarms, pressure declines, magma recedes, cools, contracts and fractures in shallow subsurface, rift dilation continues, fracture density increases at lava flow/dike rock interface due to quenching, dissimilar lithology and stress field.

Base Map: Moore and Trusdell 1991

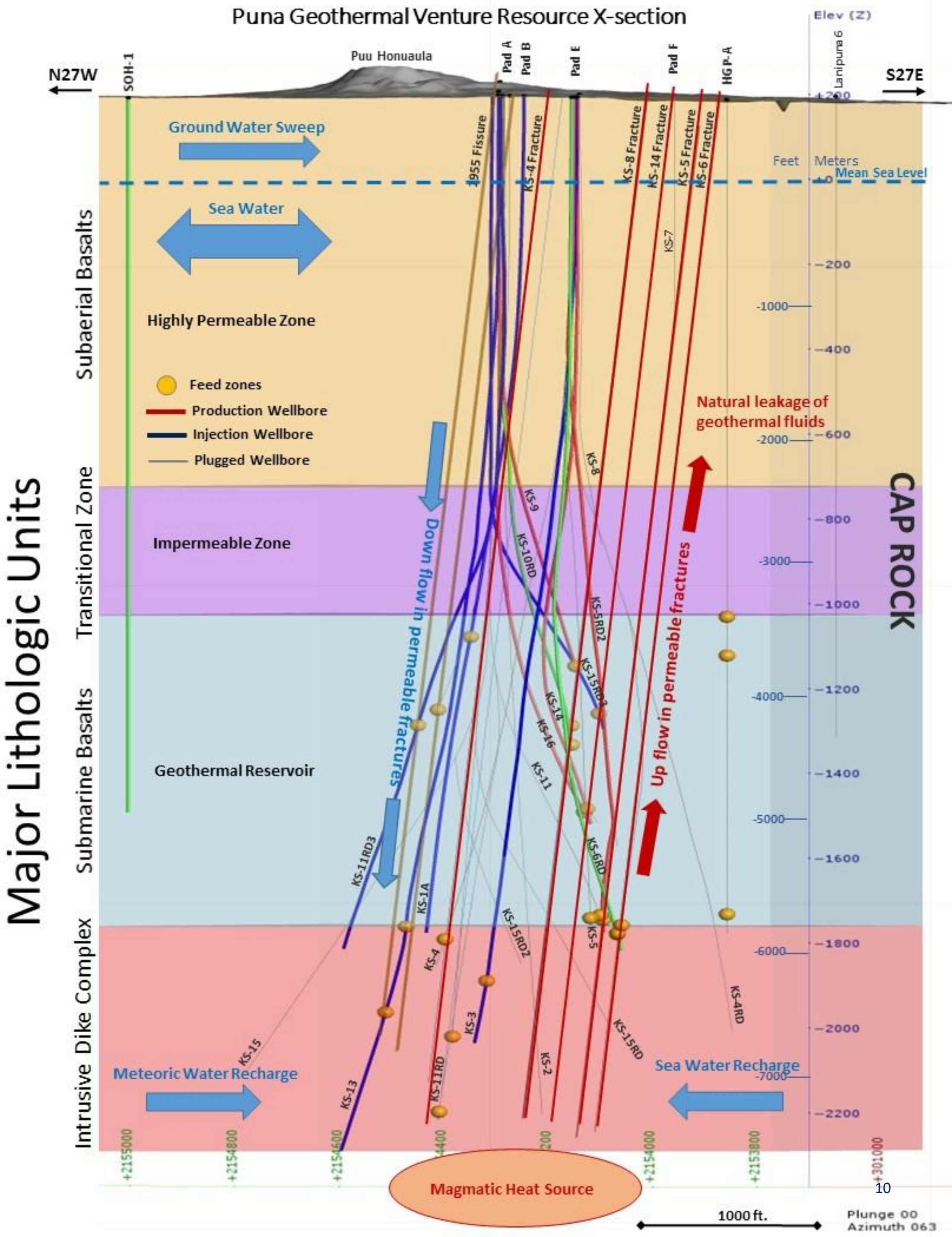


Puna Geothermal Venture
UIC Permit Application
Area of Review
Attachment B
Area of Review
Property Boundary
Geologic/Hydrologic Cross Section Line
PGV Power Plant
MW-3
MW-1
SOH-1
MW-4
KS-15
KS-2
KS-17
KS-13
KS-16
KS-9
KS-10
KS-11
KS-1
KS-1A
KS-8
KS-18
KS-7
KS-4
KS-5
KS-6
KS-14
KS-3
MW-2
Lanipuna 6
HGP-A
Hilo
Mountain View
Volcano
PGV
Lower East Rift Zone
USGS The National Map: National Boundaries Dataset, 3D Elevation Program,
10
Miles
Legend
Water Well
Production Well
Injection Well
Observation Well
Plugged or Covered Well
Well Pad
Lease Boundary
Area of Review
2018 Eruption Lava Flow Extent
0 0.125 0.25 0.5 Kilometers
0 0.125 0.25 0.5 Miles
N
Copyright:© 2013 National Geographic Society, i-cubed
300000
301000
302000
303000
2156000
2155000
2154000

SIMPLIFIED GEOLOGIC MODEL

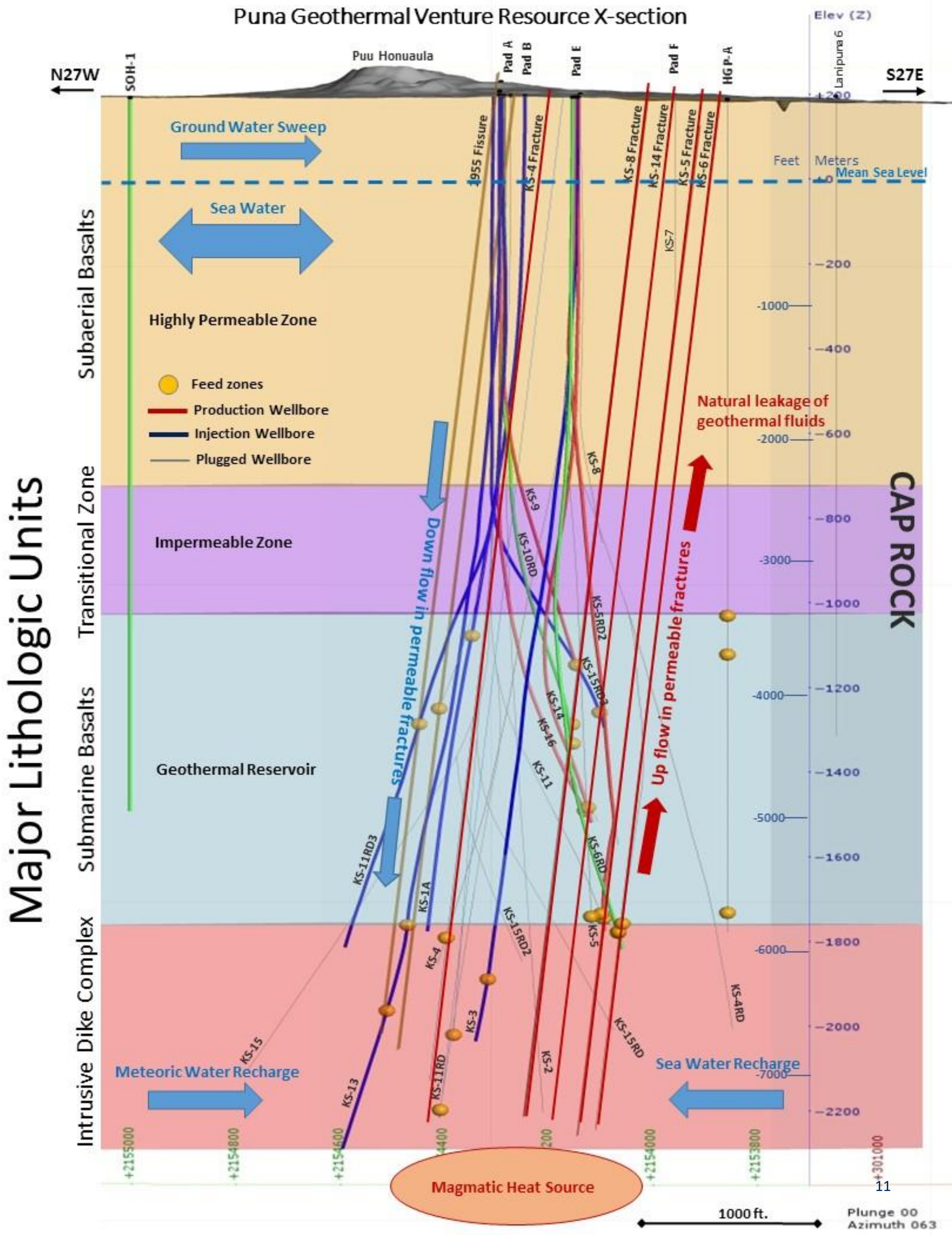
Major Lithologic Units

- Subaerial Basalts: Intercalated lava flows, scoria zones and weathered interfaces. Two types of basalts occur as (non) vesicular. Olivine-Tholeiitic & Diff-Tholeiitic
- Transitional Zone: Hyaloclastites intercalated with differentiated basalts (aerial & subaerial flows (pillows) and dikes).
- Submarine Basalts: Pillow basalts, minor hyaloclastites
- Intrusive Dike Complex: (Micro) Porphyritic differentiated basalt.

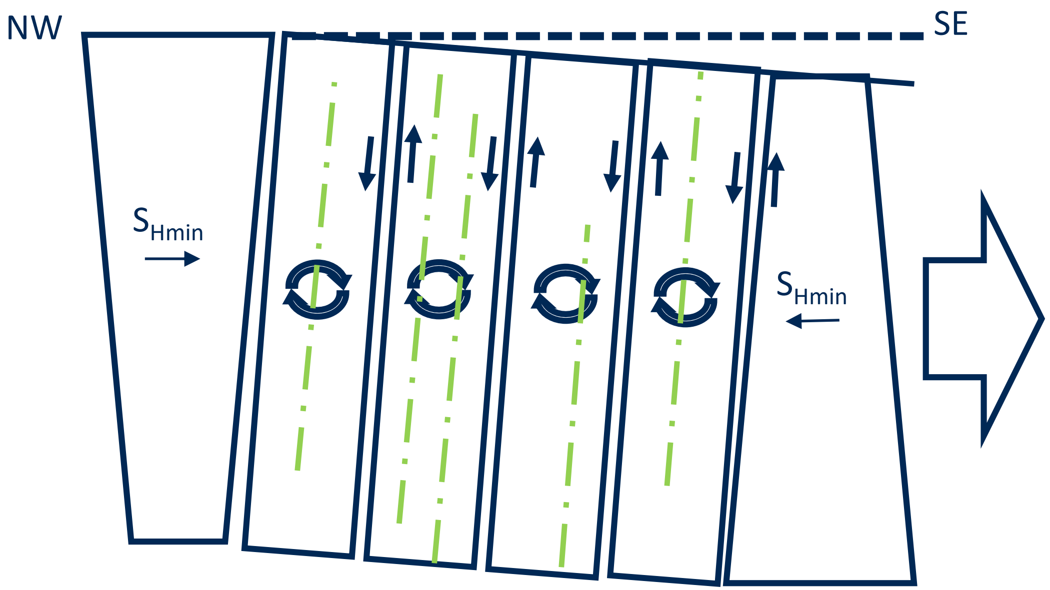


SIMPLIFIED HYDROLOGIC MODEL

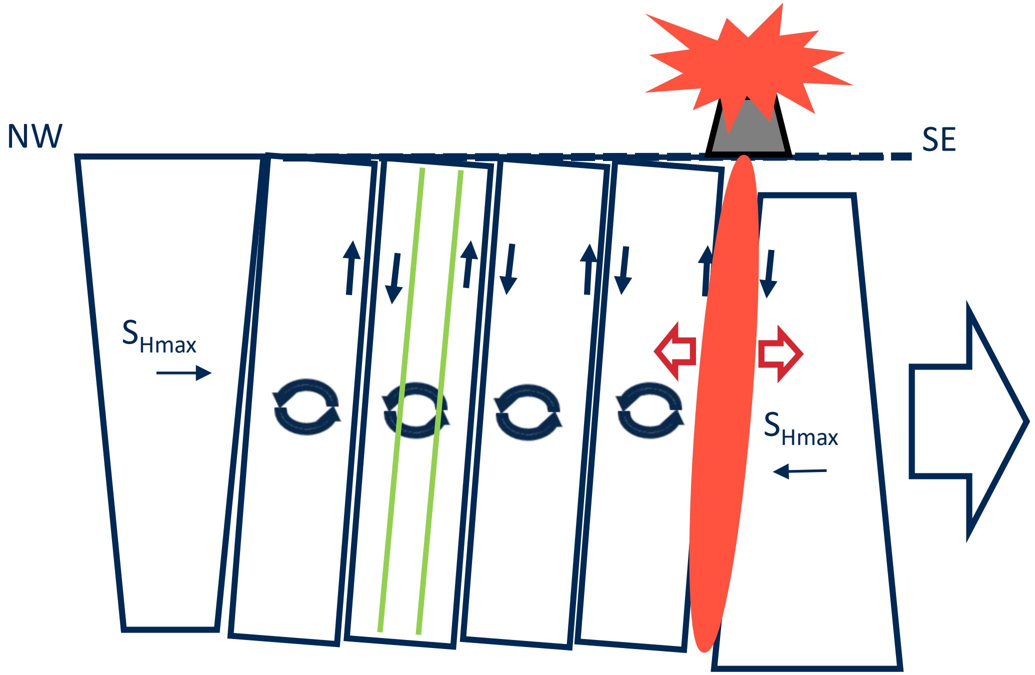
- Produced geothermal fluids are reinjected into the reservoir at depths below ~4000 ft., beneath a semi-impermeable caprock which separates the geothermal reservoir from an upper groundwater zone.
- Groundwater zone extends from the top of the caprock to the water table ~600 ft. below the surface.
- The groundwater in this upper aquifer in the vicinity of PGV is thermally and chemically influenced by natural leakage of geothermal fluids through the caprock.



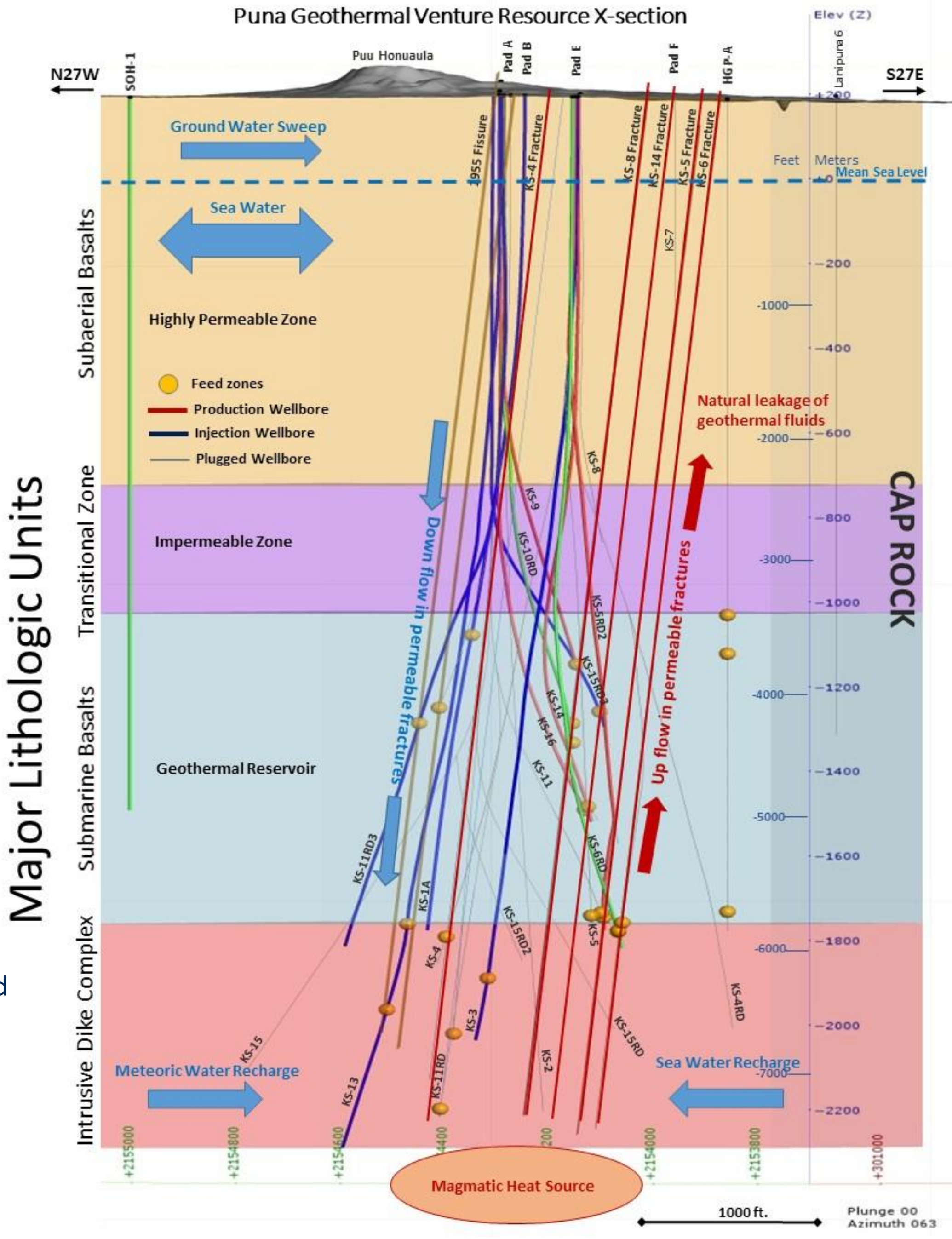
SIMPLIFIED STRUCTURAL MODEL



South flank of Kilauea displaced seaward due to lithostatic over loading. Rift zone dilates via normal displacement along high angle structures.



Episodic injection of magma further drives flank displacement but temporarily compresses rift zone (internal) and may reactivate older structures along preexisting planes of weakness.



ATTACHMENT H - Well Testing Procedures

Both the production and injection wells are subjected to various logging and testing procedures, both during and after completion. The tests ensure the integrity of the casing and cement, and help define the location of the production and injection zones. Testing may be performed by the rig, or by an independent contractor. Depending on the test, contractors may include international wellfield firms such as Schlumberger, Halliburton, Baker Atlas, Well Analysis Corporation and Roke Technologies Ltd.

Several references are attached that provide more information on specific well logging and monitoring methods. These references include:

Axelsson, Gudni (2013): *Geothermal Well Testing.* Presented at "Short Course V on Conceptual Modelling of Geothermal Systems", organized by UNU-GTP and LaGeo, in Santa Tecla, El Salvador, February 24 - March 2, 2013.

Axelsson, Gudni and Steingrímsson, Benedikt (2010): *Logging, Testing and Monitoring Geothermal Wells.* Presented at "Short Course on Geothermal Development and Geothermal Wells", organized by UNU-GTP and LaGeo, in Santa Tecla, El Salvador, March 11-17, 2012.

Danielsen, Peter Eric (2010): *Servicing Geothermal Wells during Completion and Follow-up Monitoring.* Proceedings World Geothermal Congress 2010, Bali, Indonesia, 25-29 April 2010

Rutagarama, Uwera (2012): *The Role of Well Testing in Geothermal Resource Assessment.* University of Iceland, Thesis submitted in partial fulfilment of a Magister Scientiarum degree in Geophysics.

Roke Technologies Ltd. Web site describing Quad Neutron Technology at: http://roke.ca/quad-neutron/our-technology/

Schlumberger website describing geophysical well logs at: http://www.glossary.oilfield.slb.com/Terms/w/water-flow_log.aspx/

Testing methods can include:

- CALIPER LOG - checks inside casing diameter to detect corrosion, scale, washouts, parted casing.
- ULTRASONIC LOGS- determines the internal casing diameter and thickness, and potential internal and external metal loss.
- ELECTROMAGNETIC (EM) LOGS - detects overall metal loss. Can discriminate internal and external metal loss and holes, but can be hard to interpret in the presence of two strings of casing or external hardware such as centralizers.
- RADIOACTIVE (RA) TRACER SURVEYS - detects leaks in injection well casing. A slug of iodine 131 is injected into the wellbore and a gamma ray detector is then lowered that can detect small amounts of fluid leaving the wellbore. Fluid flow behind pipe can

also be detected. Periodic RA surveys are used to demonstrate the mechanical integrity of injection wells.

- CEMENT BOND LOGS - determines the integrity and density of the cement behind the casing. The test is often unreliable in geothermal wells because of the cements used, and tooling designed for oil and gas wells where the maximum diameter is smaller than geothermal wells.
- STATIC PRESSURE AND TEMPERATURE SURVEY - measures reservoir pressure and temperature with depth. Can identify casing leaks, and hotter and cooler zones within the reservoir. Can also be used to detect injection fluid going to unauthorized depths in geothermal wells. When the cool injection fluid goes down the wellbore it cools the formation a short distance away from the well and when injection stops the wellbore heats up slowly. The cooling penetrates further out in permeable areas in the formation, so when injection stops the wellbore does not heat up as much in the injection zones. A series of static temperature surveys is run and external well integrity is assured by temperatures increasing with time above the casing shoe.
- FLOWING PRESSURE AND TEMPERATURE SURVEYS – identifies production zones and cold water infiltration zones.
- FLOWING SPINNER SURVEY - Identifies production zones and zones of production losses.
- PRESSURE TRANSIENT ANALYSIS - Measures reservoir permeability and skin factor – can quantify near wellbore blockage.
- CASING CALIPER SURVEY - Identifies holes in casing, internal metal loss to corrosion or wear, collapsed casing, and scale buildup.
- ULTRA-SONIC CASING INSPECTION - Identifies holes or corrosion in casing, internal and external metal loss, and material behind pipe (cement, water or gas).
- VIDEO SURVEY - Requires clear water or air.
- SHOE TEST – tests the integrity of the casing by pressurizing the well and measuring the leaking rate.
- FORMATION INTEGRITY TEST – tests the integrity of the formation and casing cement by pressurizing the casing and measuring the leakage rate.
- TANDEM PACKER TESTS - this type of test might be used to identify the precise location of a casing leak. If a leak is indicated by pressure datat, a spinner-temperature log may first be used to identify the leak area. A tandem packer assembly can be used to isolate the zone and measure fluid flow.

30 CFR Section 250.427 requires *a pressure integrity test below the surface casing or liner and all intermediate casings or liners…You must test to either the formation leak-off pressure or to an equivalent drilling fluid weight if identified in an approved APD.*" For PGV, the equivalent drilling fluid weight specified in our drilling programs is the 0.65 psi/ft mud pressure gradient. This is designed to stay below the leak-off pressure in order to avoid weakening the formation.

PGV uses the terminology "shoe test" or just simply a "Formation Integrity Test" (FIT). A leak off test (LOT) is different than the FIT, as the LOT tests formation until failure, while the FIT tests the formation up to a predetermined pressure before formation failure.

The FIT is the preferred term for wells tests in geothermal fields. The FIT is not a "leak off test" unless it fails and there is leak off. The FIT procedure is performed after the casing has been cemented and the cement drilled out a few feet below the casing shoe. Pressure is applied to the cement and formation below the casing shoe at a pressure gradient that is below any likely fracture pressure gradient. This assures the integrity of the formation and cement at the shoe. During subsequent operations, injection pressure is limited to the same pressure, which ensure that injectate will not go up behind the casing to shallower depths where the fracture pressure is lower or where protected aquifers might be located. PGV does not establish a specific fracture pressure for the basalt formations, because injection pressures during operations are kept well below fracture pressures. Establishing a fracture pressure gradient is generally not necessary in geothermal areas where the formation fluids are at hydrostatic pressure gradient, over-pressured zones do not exist, and high mud weights are not used.

The FIT provides a conservative limit to injection pressure. Higher injection pressures would be possible if the actual fracture pressure was measured by a step rate test, but such high pressures are generally not necessary in geothermal fields due to high permeabilities in the production/injection fracture zones, and are not desired due to the high cost of pumping injectate into the wells at high pressure. Although the FIT does not measure fracture pressure, it does ensure that injection pressures will stay below the fracture pressure. Therefore FIT's provide a safety margin above the 30 CFR subpart D method.

If the casing shoe is set in a high-permeability fracture within the geothermal reservoir, it may be difficult to get a successful FIT. In this case, the FIT test is not necessary because injection into the geothermal reservoir below the casing shoe is acceptable. However, it is still necessary to ensure that injection is not going up behind the casing. If this situation occurs, it is necessary to perform a survey that can detect flow behind the casing such as the Quad Neutron, RA Tracer Survey, Water Flow Log, Thermal Decay Time Tool, etc. These types of surveys are standard industry practice for determining external well integrity. See attached articles or website references for more information.

Quad Neutron Test: this test can determine the formation Porosity including clay free porosity, saturation, clay volume, relative permeability and relative bulk density. This test was used as a basis for our FIT in KS-13 ML-1.

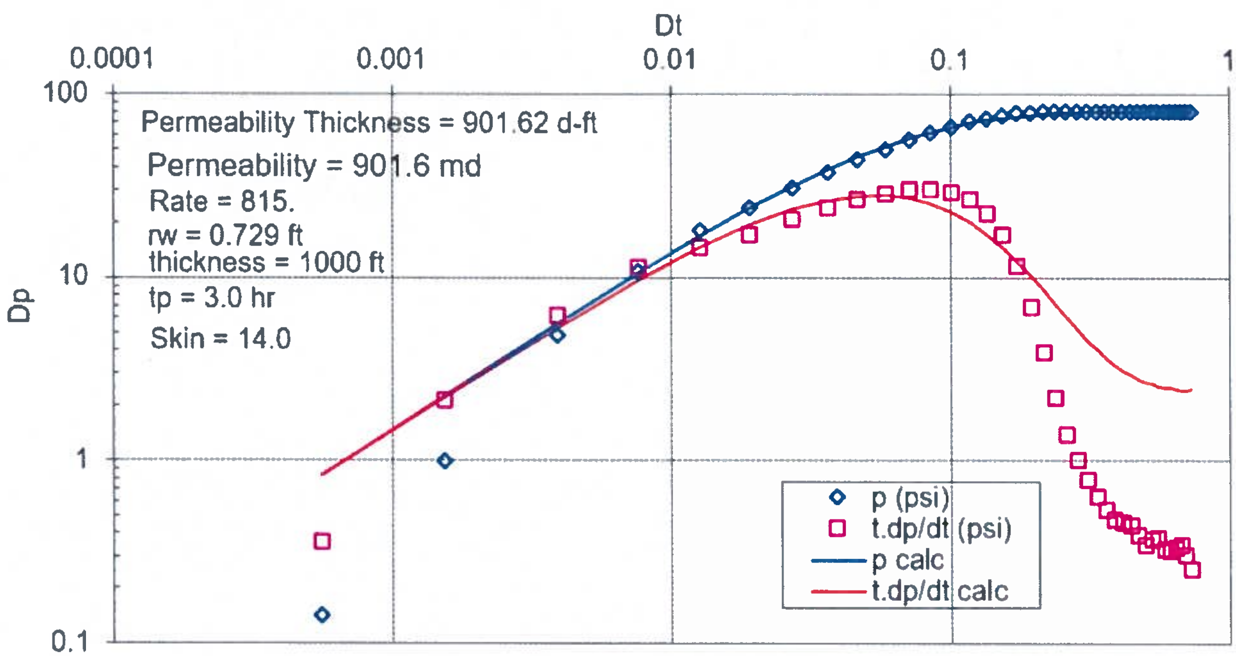
Water Flow Log: determines the direction of water flowing in and around a borehole based on oxygen activation by a radioactive source. The log may also include estimates of the flow volume and the distance from tool to flowing water.

Thermal Decay Time Tool: The thermal decay time log is a record of the rate of capture of thermal neutrons in a formation after it is bombarded with a burst of 14 Mev neutrons. Because chlorine is by far the strongest neutron absorber of the common earth elements, the response of the tool is determined primarily by the chlorine present (as sodium chloride) in the formation water. Like the resistivity log, therefore, the measured response is sensitive to the salinity and amount of formation water present in the pore volume.

A **Water Injection Test** is a rig test design to measure the well's Injectivity Index. A general Ormat procedure is as follows:

The well bottom is tagged using a sinker bar run. Following the tag run, a static pressure and temperature survey was run which determines the static water level. The injection test is then performed at multiple injection rates, while measuring the wellhead pressure in PSIG, and the downhole pressure increased in PSIA. During this injection, a spinner survey may be run to the tag depth, up to the drill pipe, down to tag depth, within the open-hole once again, and then back down. Once the tool is parked at depth, the pump rate is increased while again measuring the wellhead and downhole pressure. The well is then shut in after the injection period to record pressure fall-off. The total injection time and volume are recorded.

The Injectivity Index is calculated by the change in rate divided by the change in pressure using the Horner projected static reservoir pressure. From the pressure fall-off, the Horner projection calculates a static reservoir at the tool depth. The pressure increases and stabilization during both injection rates are then evaluated. The Injectivity Index results are interpreted in GPM/PSI. An example is provided in the following figure.



Horne, R, Modern Well Test Analysis A Computer Aided Approach, Petroway, 1995

organized by UNU-GTP and LaGeo, in Santa Tecla, El Salvador, February 24 - March 2, 2013.

GEOTHERMAL WELL TESTING

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ABSTRACT

Geothermal wells are fundamental components in geothermal research and utilization and improved understanding of geothermal systems during the last century coincided with geothermal wells becoming the main instruments of geothermal development. Geothermal wells provide access deep into the systems, not otherwise possible, which enables a multitude of direct testing and measurements of conditions at depth. The testing made possible through wells includes well testing, one of the main tools of geothermal reservoir physics/engineering. Through well testing and consequent pressure transient analysis the main reservoir parameters, such as permeability and storativity, can be estimated along with reservoir boundary conditions, if a test is sufficiently long-lasting. Such estimates consequently provide key information for conceptual model development. Pressure transient analysis is performed on the basis of appropriate reservoir models, often the well-known Theis model, and involves in fact model simulation of the pressure transient data collected. Well tests range from very short step-rate injection or production tests, via longer production (discharge or pumping), pressure build-up and interference tests to long-term (months – years) reservoir testing, often involving several wells. Tracer testing, also a kind of well testing, is the most important tool for the purpose of assessing the danger of production well cooling during long-term reinjection, if combined with comprehensive interpretation and cooling predictions (reinjection modelling).

1. INTRODUCTION

Wells or boreholes are vital components in both geothermal research and utilization, since they provide essential access for both energy extraction and information collection. The breakthrough of increased geothermal utilization and improved understanding of geothermal systems during last century coincided in fact with geothermal wells becoming the main instruments of geothermal development. Wells enable a drastic increase in geothermal energy production, compared to natural out-flow, and provide access deep into the systems, not otherwise possible. As the latter they can provide much more detailed and specific information than the various surface exploration methods, information which is fundamental for conceptual model development and revision (the subject matter of this short course), once they become available.

Geothermal wells play a variable role during both development of a geothermal resource and during their utilization. The main roles are either as temperature gradient, exploration, appraisal, production, step-out, make-up, reinjection or monitoring wells. Wells also play an essential role in all geothermal reservoir physics (or reservoir engineering) research. Such research would be particularly ineffective without the access into geothermal systems wells provide. Geothermal reservoir physics is the scientific discipline that deals with mass and energy transfer in geothermal systems and geothermal wells. It attempts to understand and quantify this flow along with accompanying changes in reservoir conditions, in particular those caused by exploitation, mainly through applying different modelling techniques (Axelsson, 2013). During the exploration stage of a geothermal resource research focuses on analysis of surface exploration data; mainly geological, geophysical and geochemical data (Axelsson and Franzson, 2012). This emphasis changes to reservoir physics research during development and utilization, with geothermal reservoir physics e.g. having the potential to play a key role in geothermal resource management.

The purpose of geothermal reservoir physics is, in fact, twofold: To obtain information on the nature, reservoir properties and physical conditions in a geothermal system and to use this information to predict the response of reservoirs and wells to exploitation. Based on the latter the energy production capacity of a geothermal resource can be assessed. Response predictions also aid in the different aspect of the management of geothermal resources during utilization (Axelsson, 2008). Geothermal reservoir physics emerged as a separate scientific discipline in the 1970s even though some isolated studies of the physics of geothermal systems had been conducted before that in countries like Iceland, New Zealand and the USA (Grant et al., 1982). Geothermal reservoir engineering, as well as geothermal technology in general, draws heavily from the theory of ground water flow and petroleum reservoir engineering, the former having emerged in the 1930's. However, geothermal reservoirs are in general considerably more complex than ground-water systems or petroleum reservoirs. The different aspects of geothermal reservoir physics are e.g. discussed by Bödvarsson and Witherspoon (1989), Grant and Bixley (2011) and Axelsson (2012).

The testing made possible through wells includes well testing, one of the main tools of geothermal reservoir physics. It is more correctly called pressure transient testing because it involves disturbing the pressure state of a reservoir, through mass extraction or injection, and observing the resulting pressure transients. Through well testing and consequent pressure transient analysis the main reservoir parameters can be estimated along with reservoir boundary conditions. Such estimates consequently provide key information for conceptual model development. Pressure transient analysis is performed on the basis of appropriate reservoir models. Well tests range from very short step-rate injection or production tests, via longer production (discharge or pumping), pressure build-up and interference tests to long-term (months – years) reservoir testing, often involving several wells.

Tracer testing, which is also a kind of well testing, yet not pressure transient testing, is the most important tool to study the connections between reinjection wells and production wells and to assess the danger of production well cooling during long-term reinjection, if combined with comprehensive interpretation and cooling predictions (reinjection modelling).

This paper starts out by reviewing the different types of geothermal wells, as background information. After that it discusses the main methods of pressure transient well testing used during geothermal research and development, along with other reservoir research conducted through wells, and consequently the main pressure transient analysis methods. Subsequently the paper discusses briefly the application of tracer testing in reinjection research and their subsequent analysis. The paper is concluded by general conclusions and recommendations.

2. GEOTHERMAL WELLS

2.1 General

Wells or boreholes are vital components in both geothermal research and utilization, since they provide essential access for both energy extraction and information collection, as already mentioned. Deep geothermal drilling didn't really commence on a large scale until the middle of the 20th century even though some geothermal drilling had already started a century before that. Deep (150–200 m) geothermal drilling started in Larderello, Italy, in 1856 (Grant and Bixley, 2011) and the first deep (~970m) geothermal well in Hungary was drilled in Budapest from 1868 to 1878 (Szanyi and Kovács, 2010).

The design, drilling and construction of geothermal wells are discussed in the geothermal literature, e.g. in the proceedings of a short course held by UNU-GTP and LaGeo in San Salvador in March 2012 (see http://www.unugtp.is/page/sc-14/). Sarmiento (2007) discusses drilling practises in The Philippines in particular, where extensive experience has accumulated during the countries extensive geothermal development. Typically the upper parts of a geothermal well are closed off by a series of casings; to stabilize the well, to close off non-geothermal hydrological systems and for safety reasons. The deeper parts of the well are either fully open or cased with a so-called liner, which is not cemented in place but perforated in selected intervals, to allow fluid (water and/or steam) to flow from the reservoir into the well. The most significant difference between geothermal and petroleum wells are the following:

(i) Geothermal wells are most often drilled in hard, igneous rocks, which are more difficult to drill than the sedimentary environment of petroleum wells.
(ii) The open production sections of geothermal wells are quite long in comparison with those of petroleum wells, ranging from a few hundred metres to more than 2 km.
(iii) Yet geothermal wells usually have some discrete in-flow sections (feed-zones, see below).
(iv) Geothermal wells often encounter high temperatures and pressures, sometimes associated with blow-out danger due to explosive boiling.
(v) Water is commonly used as drilling fluid for open sections in contrast with drilling mud most commonly used in petroleum wells to avoid clogging any feed-zones (also reduced pollution danger).
(vi) The drilling of successful geothermal wells often involves large, or even total, circulation losses.
(vii) Geothermal production wells are generally of larger diameter (up to a few tens of cm's) than petroleum wells, because of greater flow-rates involved.

Grant and Bixley (2011) discuss some of these in more detail.

A geothermal well is connected to the geothermal reservoir through feed-zones of the open section or intervals. The feed-zones are either particular open fractures or permeable aquifer layers. In volcanic rocks the feed-zones are often fractures or permeable layers such as interbeds (layers in-between different rock formations) while in sedimentary systems the feed-zones are most commonly associated with a series of thin aquifer layers or thicker permeable formations. Yet fractures can also play a role in sedimentary systems. In some instances a well is connected to a reservoir through a single feed-zone while in other cases several feed-zones may exist in the open section, but often one of these is the dominant one.

Geothermal wells can be classified as one of three principal types:

(a) liquid-phase low-temperature wells, which produce liquid water at well-head (pressure may be higher than atmospheric, however),
(b) two-phase high-temperature wells where the flow from the feed-zone(s) is liquid or two-phase and the wells produce either a two-phase mixture or dry-steam or
(c) dry-steam high-temperature wells where the flow from the feed-zone(s) to the well-head is steam-dominated.

In the liquid-phase and dry-steam wells the inflow is single phase liquid water or steam, respectively, while two-phase wells can be furthermore classified as either liquid or two-phase inflow wells. In multi feed-zone two-phase wells one feed-zone can even be single-phase while another one is two-phase.

In general the productivity of geothermal wells is a complex function of:

(1) well-bore parameters such as diameter, friction factors, feed-zone depth and more,
(2) feed-zone temperature and enthalpy,
(3) feed-zone pressure, which depends directly on reservoir pressure and reservoir permeability,
(4) well-head pressure or depth to water level during production and
(5) temperature conditions around the well.

Most of these parameters can be assumed approximately constant for reservoirs under production, except for the reservoir pressure (3), which varies with time and the overall mass-extraction from the reservoir. The feed-zone temperature and enthalpy may also vary with time in some cases, albeit usually more slowly than reservoir pressure. Axelsson and Steingrímsson (2012) discuss the multidisciplinary research conducted during drilling, testing and monitoring of geothermal wells, research not discussed here.

Finally it should be mentioned that geothermal wells are often stimulated following drilling, either to recover permeability reduced by the drilling operation itself, to enhance lower than expected near-well permeability or to open up connections to permeable structures not directly intersected by the well in question. Axelsson and Thórhallsson (2009) review the main methods of geothermal well stimulation with emphasis on methods applied successfully in Iceland. The methods most commonly used involve applying high-pressure water injection, sometimes through open-hole packers, or intermittent cold water injection with the purpose of thermal shocking. Stimulation operations commonly last a few days while sometimes stimulation operations have been conducted for some months. The stimulation operations often result in well productivity (or injectivity) being improved by a factor of 2-3.

2.2 Types of geothermal wells

The different types of geothermal wells are listed and described briefly below (see Axelsson and Franzson, 2012):

(1) **Temperature gradient wells** are generally both slim and quite shallow, most often only around 50 m in depth, even though in some instances they may reach a few hundred metres depth. Their main purpose is to study shallow temperature conditions (temperature gradient) and estimate heat flow. In contrast with other geothermal wells temperature gradient drilling can in fact be classified as a surface exploration tool.
(2) **Exploration wells** are deeper wells intended to extend into the geothermal system being explored, i.e. to reach a specific target. Their main purpose is to study temperature conditions, permeability and chemical conditions of the target. Exploration wells are either so-called slim wells with diameter < 15 cm, which are drilled for the sole purpose of exploring conditions at the target depth, or exploration wells designed as production wells (full diameter wells). The former can be used to estimate the capacity of production wells later drilled to reach the same target(s). The latter can later be converted to production wells, however, if successful.
(3) **Production wells** are wells drilled with the sole purpose of enabling production of geothermal energy (as hot liquid, two-phase mixture or steam) from a specific target, or a geothermal reservoir. Their design is of paramount importance, e.g. the casing program applied. Production wells are either designed for spontaneous discharge through boiling (high-temperature reservoirs) or for the application of down-hole pumps (lower temperature reservoirs).
(4) **Step-out wells** are either exploration or production wells drilled to investigate the extent, of a geothermal reservoir already confirmed. A step-out well either approaches the edge, or boundary, of a reservoir or is drilled beyond it. A number of step-out wells in different directions may be required if a given reservoir is extensive in area.
(5) **Make-up wells** are production wells drilled inside an already confirmed reservoir, which is being utilized for energy production, to make up for production wells which are either lost

through damage of some kind (collapse, scaling, etc.) or to make up for declining capacity of wells.

(6) **Reinjection wells** are used to return energy-depleted fluid back into the geothermal system in question or even to inject water of a different origin as supplemental recharge. The location of reinjection wells is variable as reinjection can either be applied inside a production reservoir, on its periphery, above or below it or outside the main production field, depending on conditions and the purpose of the reinjection.

(7) **Monitoring wells** are used to monitor changes in geothermal systems, mainly after utilization starts, mostly pressure and temperature changes. These are in most cases already existing wells, such as exploration wells or abandoned production wells. Active production wells are sometimes used for monitoring purposes (chemical content, temperature and pressure). Carefully designed and comprehensive monitoring is the key to successful management of geothermal resources during utilization.

(8) **Unconventional wells** are either wells of unconventional design or wells drilled into parts of geothermal systems generally not used for energy production. Examples are wells that are deeper than normal, well drilled into magma or wells drilled into supercritical conditions.

The different types of wells play a role during different stages of geothermal research and development, and all types can contribute data used in conceptual model development. Pressure transient testing can e.g. be performed in all well-types while tracer tests are commonly performed between reinjection and production wells. The key to the successful drilling of any type of geothermal well is, furthermore, correct siting and design of the well based on a clear definition and understanding of the drilling target aimed for, founded on all information available at any given time. This is best achieved through a comprehensive and up-to-date conceptual model incorporating, and unifying, the essential physical features of a geothermal system. Geothermal drilling targets and well siting are discussed in a separate presentation at this short course (Axelsson et al., 2013). It may also mbe mentioned that Stefánsson (1992) analyses the success of geothermal development, which depends to a great extent on the success of drilling.

3. RESERVOIR RESEARCH CONDUCTED THROUGH GEOTHERMAL WELLS

3.1 During drilling

The principal research conducted during drilling of geothermal wells is achieved through logging of the wells, often called wireline logging. This involves measuring various contrasting, partly unrelated, parameters for different purposes as a function of depth. Some of these are drilling technology related, others for logging geological parameters and still others for reservoir physics purposes. The following are the main logging methods applied during geothermal well drilling (see Axelsson and Steingrímsson (2012) for more details):

(A) Caliper and cement bond logging aimed at measuring variations in well diameter and assessing the integrity of casing cementing. In addition imaging of casings and other parts of wells by video cameras is increasingly being used.

(B) Geophysical logging (resistivity logs, neutron-neutron logs, gamma-gamma logs, sonic logs and natural gamma ray logs) aimed at estimating different physical properties of the rock formations intersected by the well. This type of logging supplements drill cutting analysis, in particular for depth intervals where drill cuttings aren't available.

(C) Fracture imaging is increasingly being used to study specific fractures and fracture distributions in wells. The method most often applied is televiewer logging, which provides an extremely valuable addition to other logging methods, and circulation loss analysis, aimed at understanding feed-zones in wells.

(D) Temperature and pressure logging can be viewed as the main reservoir physics logging performed during drilling. In addition spinner logging is often applied to estimate fluid flow in wellbores as well as inflow or outflow through feed-zones.

Pressure transient well testing (the subject of this paper) is usually not applied during drilling. Exceptions include situations when the outcome of a drilling operation needs to be assessed before drilling is completed, which can be done through short-term step-rate injection or production testing, comparable (often shorter, however) to tests normally applied at well completion (see below). The results of such testing are sometimes used to determine whether a drilling operation should be terminated or not.

During the drilling phase of a well temperature and pressure logging has a few different research purposes; firstly to evaluate well conditions regarding the drilling operation itself, secondly to locate feed-zones (inflow or outflow zones) and thirdly to estimate reservoir temperature and pressure. During drilling temperature and pressure are, however, lowered by drilling fluid circulation as well as being often affected by inflow or outflow through feed-zones or internal flow between feed-zones, and it's difficult to estimate reservoir temperature and pressure accurately. Axelsson and Steingrímsson (2012) discuss the methods used for that purpose.

3.2 At well completion

At well completion reservoir physics research kicks in at full force, including well testing, with the main purpose being to assess the result of the drilling operation. If the outcome is deemed satisfactory the drilling operation is stopped, otherwise drilling may be continued to greater depth, or a program of well stimulation may be initiated (see later). The main phases of conventional completion program for a geothermal production well are as follows:

(1) Temperature and pressure logging, sometimes accompanied by spinner logging, to evaluate location and relative importance of feed-zones as well as temperature conditions prior to later phases of the completion test (due to temperature limitations of instruments used).
(2) Geophysical logging and fracture imaging of the production part of the well.
(3) Step-rate well-testing; through injection in high-temperature wells or production in low-temperature wells. Pressure (and sometimes temperature) transients are preferably measured down-hole.
(4) Temperature and pressure logging is normally performed after, sometimes even during step-rate testing. Spinner logging can be beneficial to assess feed-zones.

The purpose of the step-rate well-testing, which is the main reservoir physics research conducted at the end of drilling a well, is to obtain a first estimate of the possible production capacity of a well and to estimate its production characteristics. In the case of high-temperature wells this estimate is only indirect since it's not performed at high-temperature, production conditions. Step-rate well-testing usually lasts from several hours to a few days. The following are the parameters usually estimated on basis of step-rate test data:

(a) Injectivity index, defined as $\boldsymbol{II} = \Delta q/\Delta p$, with Δq the change in flow-rate and Δp the change in down-hole pressure, usually based on measured values at the end of each step. In the case of low-temperature wells tested through production step testing a comparable index is defined, termed productivity index (***PI***). A productivity index is also estimated during production testing of high-temperature wells. This will be discussed later in the present chapter.
(b) Formation transissivity or permeability-thickness ($\boldsymbol{T}$ or $\boldsymbol{kh}$, respectively), to be discussed in Chapter 4 below.
(c) Formation storage coefficient ($\boldsymbol{S}$) or storativity ($\boldsymbol{s}$), also to be discussed in Chapter 4.
(d) Skin factor of a well and wellbore storage capacity (see Chapter 4).

The injectivity index (as well as the productivity index) is a simple relationship, approximately reflecting the capacity of a well, which is useful for determining whether a well is sufficiently open to be a successful producer and for comparison with other wells. It neglects, however, transient changes and turbulence pressure drop at high flow-rates. For liquid phase low-temperature wells a more accurate productivity relationship can usually be put forward relating mass flow-rate (***q***) and well pressure (***p***):

$$p = p_0 - b(t)q - Cq^2 \tag{1}$$

The pressure can either be measured as down-hole pressure, depth to water-level if pumping from the well is required, or well-head pressure if flow from the well is artesian. The term $\boldsymbol{p_0}$ represents the initial well pressure before production starts, $\boldsymbol{b(t)q}$ transient changes in well pressure reflecting transient changes in reservoir pressure (addressed in Chapter 4) and $\boldsymbol{Cq^2}$ turbulent and frictional pressure changes in the feed-zones next to the well, where flow-velocities are at a maximum, and in the well itself. The term $\boldsymbol{b(t)}$ depends on the properties of the reservoir in question, such as permeability and storativity. The injectivity/productivity index is, therefore, in fact an approximation of this term. To be exact the term will also include interference (due to production and/or reinjection) from other nearby wells. Figure 1 shows examples of productivity curves (often also called deliverability or output curves) for three liquid-phase low-temperature geothermal wells with vastly variable production characteristics, based on real Icelandic low-temperature examples.

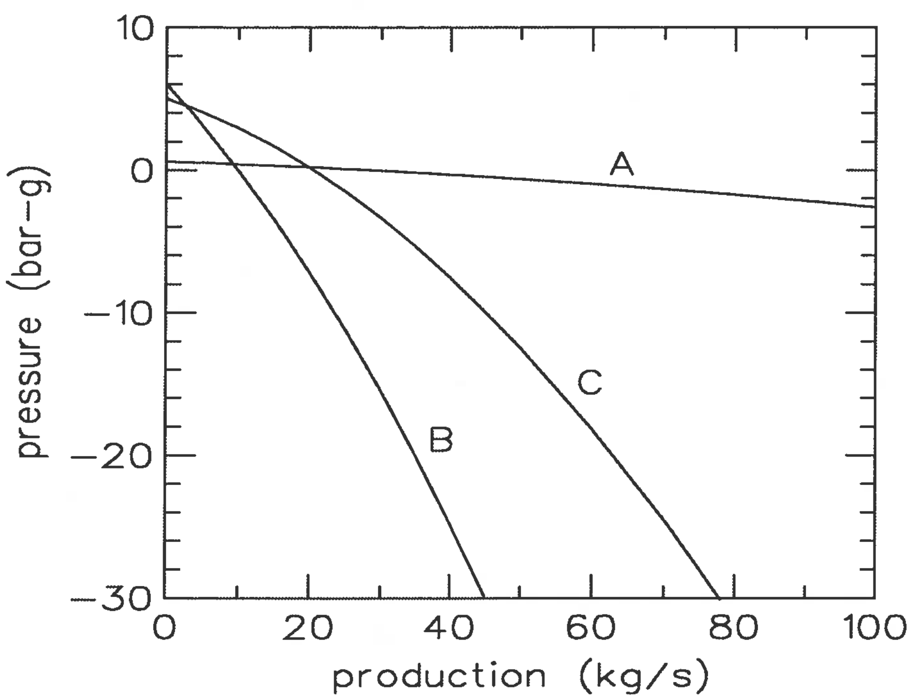

FIGURE 1: Examples of productivity curves (i.e. Equation (1)) for liquid-phase low-temperature geothermal wells with varying characteristics. Based on real Icelandic examples (see Axelsson and Gunnlaugsson, 2000)

It may be mentioned that Rutagarama (2012) presents a good treatise on the role of well-testing in geothermal resource assessment while Sarmiento (2011) discusses completion testing in more detail than done here, based on examples from high-temperature geothermal fields in the Philippines. Pressure transient analysis of step-rate well test data, collected during either injection or production, is discussed in Chapter 4 below and some examples presented.

3.3 Stimulation related testing

Geothermal wells are often stimulated following drilling, either to recover permeability reduced by the drilling operation itself, to enhance lower than expected near-well permeability or to open up connections to permeable structures not directly intersected by the well in question. Axelsson and Thórhallsson (2009) review the main methods of geothermal well stimulation with emphasis on methods applied successfully in Iceland. The methods most commonly used involve applying high-pressure water injection, sometimes through open-hole packers, or intermittent cold water injection with the purpose of thermal shocking. Chemical stimulation (mostly applying acid) methods are also used. Experimental procedures, such as using deflagration to stimulate wells and propellants to maintain stimulation achieved, have also been tested (Axelsson and Steingrímsson, 2012). Stimulation operations commonly last a few days while in some instances stimulation operations have been conducted for some months. The stimulation operations often result in well productivity (or injectivity) being improved by a factor of 2-3.

Emphasis is placed on careful reservoir monitoring during stimulation operations. Seismic monitoring has e.g. provided valuable information in some few cases. Further research and "state of the art" technology are needed to better understand stimulation processes, however, and to improve the outcome of geothermal stimulation operations. The results of stimulation operations are usually assessed through repeated step-rate well-tests (see Section 3.2) and by comparing injectivity (or productivity) indices estimated before, during and after stimulation operations. Changes in skin factor can also be used to evaluate the outcome of such operations.

3.4 During well warm-up and production testing

After the drilling of a geothermal well is completed a well is usually allowed to recover in temperature (heat up) from the cooling caused by drilling fluid circulation and cold water injection. How long depends on local conditions and the development project being followed, but this usually takes a few months. The principal reservoir engineering research conducted during this period is repeated temperature and pressure logging. The temperature data thus collected is used to estimate the undisturbed system temperature, often called formation temperature, as wells usually don't recover completely during the recovery period. Different methods can be used for this estimation, but the method most often applied is the so-called Horner method (see Axelsson and Steingrímsson, 2012). No pressure transient testing is conducted during the warm-up period.

After a well has been allowed to warm up sufficiently it is ripe for output testing. In the case of high-temperature wells this usually involves spontaneous discharge through boiling at depth in the wellbore, which creates the pressure drop necessary to drive the flow of geothermal fluid from the reservoir, through the well, and to the surface (discharge testing). In the case of lower temperature wells either sufficient overpressure in the reservoir, which creates free-flow (artesian) from wells, or pumping, is required for output testing. In many cases high temperature wells need to be discharge stimulated through a variety of methods before discharge can be sustained. Such methods are e.g. discussed by Sarmiento (2011).

Measuring the well discharge of single-phase (liquid water or dry steam) wells is relatively straight-forward whereas measuring the discharge (both mass- and energy-flow) of a two-phase well is much more complex. This involves measuring, or estimating, two out of four key parameters; liquid-flow (q_w), steam-flow (q_s), total flow (q_{total}) or enthalpy of the flow (h_t). Once any two have been determined the other parameters can be estimated based on the following equations:

$$X = q_s / q_{total} \tag{2}$$

$$q_{total} = q_w + q_s \tag{3}$$

$$h_t = Xh_s + (1-X)h_w \tag{4}$$

Here X is the mass-fraction of steam and h_s and h_w enthalpy of water and steam, respectively, at separation conditions on surface.

The following are the main methods used to estimate the output of two-phase wells at surface (see also Grant and Bixley, 2011):

(1) Liquid and steam phases are separated (in a separator) and each phase measured separately. Probably the most accurate method but requires the most complex instrumentation.
(2) This method applies to wells with liquid inflow and known feed-zone temperature. Liquid flow is measured after separation and enthalpy of flow estimated on basis of feed-zone temperature.
(3) This method also applies to wells with liquid inflow and known feed-zone temperature. Total flow estimated by the Russel James method and enthalpy of flow on basis feed-zone temperature. The Russel James method is an empirical method, relating total flow and flowing enthalpy, based on measuring the critical lip-pressure at lip of a pipe discharging the two-phase mixture (James, 1970; Grant et al., 1982).
(4) A combination of using the Russel James method on the total flow and consequently measuring the liquid flow-rate after separation.
(5) Using two different chemical tracers to measure the flow-rate of each of the phases in a pipeline (Hirtz et al., 2001). This method is increasingly being used with success, as it doesn't require disruption of power production.

Figure 2 shows an example of discharge test data from the Olkaria Domes field in Kenya. It shows a typical behaviour resulting from the well heating up, actually continuing from the warm-up period after drilling, i.e. enthalpy increases and water flow decreases as the test progresses. In this case the test lasted about a month, but ideally discharge tests should last until an approximate equilibrium is reached, which often may take several months. In some cases equilibrium is not attained. The behaviour of discharging wells is, however, quite variable, depending on the nature of the geothermal reservoir involved and well properties, as e.g. discussed by Bödvarsson and Witherspoon (1989) and Grant and Bixley (2011).

The productivity of geothermal wells is often presented through a simple relationship between mass flow-rate or production (measured as mentioned above) and the corresponding pressure change, either in down-hole or well-head pressure, as a first-order approximation, as already discussed (see discussion on injectivity/productivity above). This relationship is often termed production characteristics or well deliverability (output curve). In general the productivity of geothermal wells is a complex function of well-bore parameters (diameter, friction factors, feed-zone depth, skin factor, etc.), feed-zone temperature and enthalpy, feed-zone pressure, reservoir permeability and storativity, well-head pressure or depth to water level during production and temperature conditions around the well. For two-phase high-temperature wells a simple relationship as given by Equation (1) can't be set up between flow-rate and well-head pressure.

Figure 3 shows examples of productivity curves for two types of two-phase high-temperature geothermal wells with vastly variable production characteristics. It exemplifies a clear distinction between wells with single phase feed-zone inflow, which show typical bell-shaped curves like liquid-phase wells (Figure 1), and wells with two-phase inflow, which show little variation in output with changes in well-head pressure. The possible reasons for the characteristics of the latter wells have been discussed by Stefánsson and Steingrímsson (1980) as well as Bödvarsson and Witherspoon (1989).

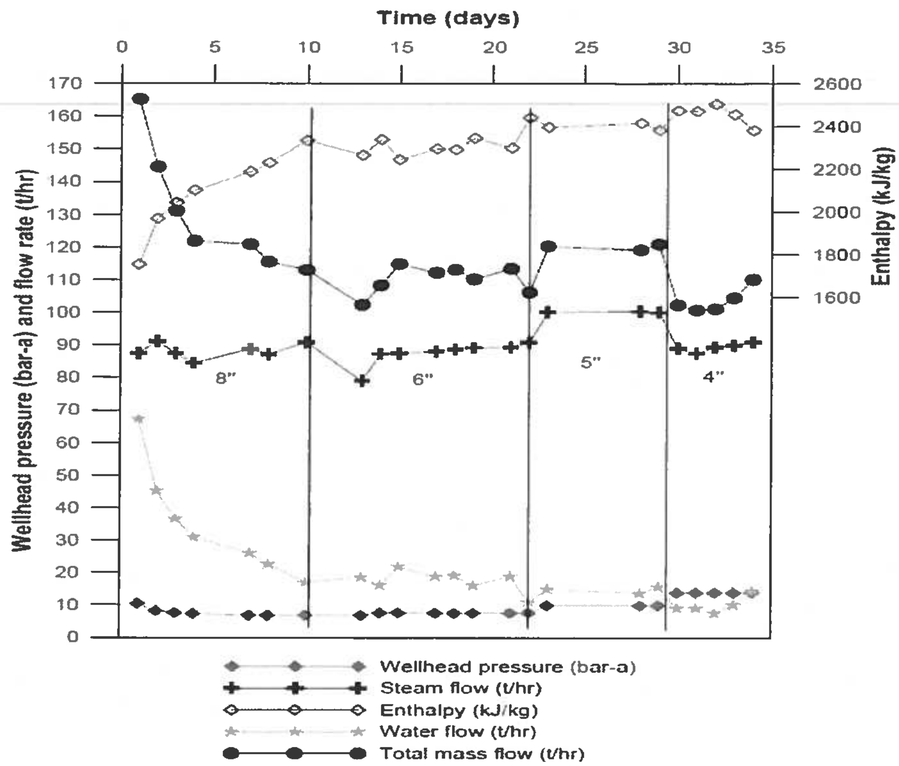

FIGURE 2: Discharge test data from well OW-915A in the Olkaria Domes field in Kenya (Mwarania, 2010)

When analysing data from flowing two-phase wells researchers need to resort to so-called wellbore simulators, i.e. computer software which numerically solves the relevant physical equations to simulate flow-, pressure- and energy conditions in the wells in question. These include mass conservation, pressure changes due to acceleration, friction and gravitation as well as energy conservation. The *HOLA* wellbore simulator is a good example of such software (Björnsson and Bödvarsson, 1987) while several other newer wellbore simulators also exist.

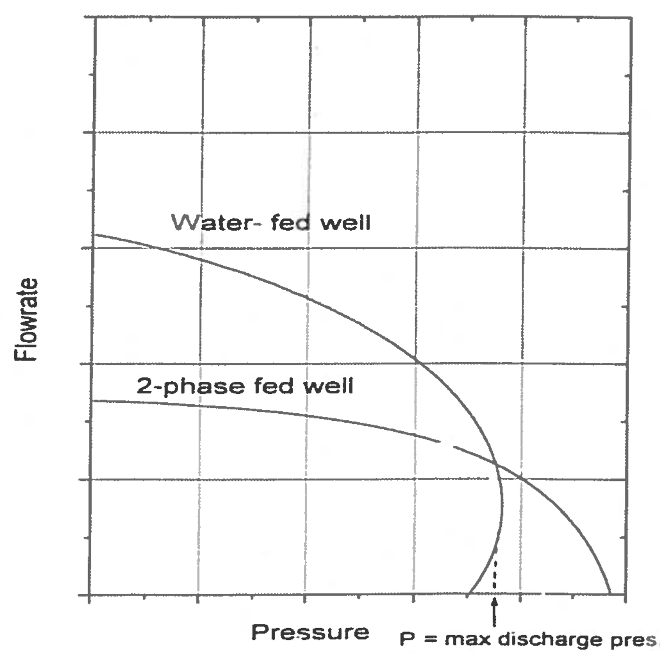

FIGURE 3: General examples of productivity curves for two types of two-phase high-temperature geothermal wells (Axelsson and Steingrímsson, 2012)

An extremely important part of discharge testing is monitoring of down-hole pressure during testing, either continuously or intermittently. This is not done in nearly all cases, however, as it may be technically difficult and/or quite expensive. If such data are available it is common to define a productivity index (***PI***) simply as the ratio between a change in mass flow-rate and a corresponding change in well pressure, preferably measured at the main feed-zone of a well, as first-stage analysis. For low-temperature, single-phase wells the productivity index is normally quite comparable to the wells injectivity index, if that has been estimated. This is, however, not the case for high-temperature, two-phase wells because of drastically contrasting conditions during injection of colder fluids and high-temperature production. This can be seen clearly in Figure 4 which shows a comparison of productivity and injectivity indices for a number of high-temperature wells worldwide. The figure shows a considerable scatter, at least not a clear one-to-one relationship. A conservative relationship assuming that $PI = II/3$, which has been suggested, is supported by the figure. This is logical in the case of two-phase wells where boiling causes a much greater pressure draw-down than during injection. Yet it seems evident that in the case of highly productive wells the productivity index is considerably larger than the injectivity index (Axelsson and Thórhallsson, 2009).

Conventional pressure transient analysis of down-hole pressure data measured during discharge testing is of course a more accurate method of analysis than the estimation of a productivity index. The analysis methods described in Chapter 4 may be used for this purpose; they are in fact the same methods as used for the analysis of step-rate well-test data.

In addition to simple monitoring of down-hole pressure during discharge testing, supplementary pressure transient testing is sometimes performed. This involves in particular pressure recovery monitoring after discharging wells are shut in and pressure interference monitoring in near-by monitoring wells. Such data add greatly to the reservoir physics analysis of discharge tests. It should be noted, however, that in the case of high-temperature, especially two-phase, reservoirs pressure propagation is very slow so pressure interference may be limited. In lower temperature, liquid-dominated, reservoirs interference testing is extremely valuable.

3.5 Long term monitoring

Management of geothermal resources relies on adequate knowledge on the corresponding geothermal system and the monitoring of their response to long-term utilization is therefore essential (Monterrosa and Axelsson, 2013; Axelsson, 2008). Production response monitoring provides in fact some of the most important data on the nature and characteristics of geothermal systems, information which is also indispensable for the development of geothermal conceptual models. It is, in particular, essential for the revision of conceptual models previously developed on the basis of exploration and well data. If the understanding of a geothermal system is adequate, monitoring will enable changes in the reservoir to be seen in advance. Timely warning is thus obtained of undesirable changes such as decreasing generating capacity due to declining reservoir pressure or steam-flow, insufficient injection capacity or possible operational problems such as scaling in wells and surface equipment or corrosion. The importance of a proper monitoring program for any geothermal reservoir being utilised can thus never be over-emphasised. In addition utilization and monitoring can be viewed as really long-term reservoir testing, i.e. a continuation of the production testing discussed above, even though that type of testing is not performed under controlled conditions. Long-term pressure transients monitored during years of utilization, together with data on the mass extraction (always variable) causing it, constitutes, in particular, long-term pressure transient testing.

Monitoring the physical changes in a geothermal reservoir during exploitation is in principle simple and involves measuring the (1) mass and heat transport, (2) pressure, and (3) energy content (temperature in most situations). This is complicated in practise, however (Axelsson and Gunnlaugsson, 2000). Measurements must be made at high-temperatures and pressures and reservoir access for measurements is generally limited to a few wells, and the relevant parameters can't be measured directly throughout the remaining reservoir volume. Monterrosa and Axelsson (2013) and Axelsson and Steingrímsson (2012) discuss response monitoring in more detail, including the parameters that need to be measured, as well as presenting several relevant examples. It should be mentioned that such physical monitoring data are essential for calibration of models of geothermal systems used to assess their production capacity and for long-term management purposes.

In addition to monitoring physical changes the chemical content of produced water and/or steam also needs to be monitored. Finally repeated indirect monitoring, which involves monitoring the changes occurring at depth in geothermal systems through various surface observations (mainly geophysical surveying, e.g. combined surface deformation and micro-gravity monitoring), can provide valuable additional information, such as on changes in the mass balance of a geothermal system (Axelsson and Steingrímsson, 2012; Axelsson, 2008).

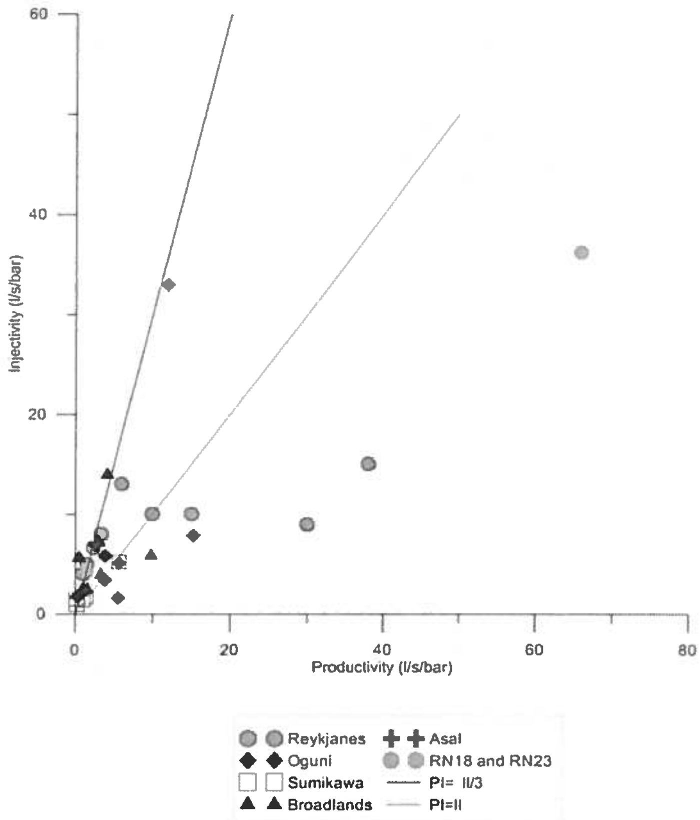

FIGURE 4: The relationship between productivity and injectivity indices for several high-temperature geothermal wells worldwide (Rutagarama, 2012). The red line represents ***PI = II*** while the blue line represents ***PI = II***/3

3.6 For reinjection wells

In the case of reinjection wells, either drilled specifically as such or other types of wells converted into reinjection wells, much of the same reservoir physics research is conducted as described above. The main difference is that reinjection wells don't need to be discharge tested so a step-rate injection test suffices. After well completion injection testing needs to be continued for a long period, usually several months. During this long-term injection testing tracer test are often conducted to study the connection between the designated reinjection well and near-by production wells, with the danger of cooling of the production wells in mind. Tracer testing in geothermal operations is discussed in Chapter 5 below, while a more detailed discussion of other aspects of reinjection well testing and research is presented by Axelsson (2012b). It may be specifically mentioned, however, that the injectivity of reinjection wells sometimes continues to increase during long-term injection, most likely due to thermal stimulation.

4. PRESSURE TRANSIENT ANALYSIS

Pressure transient analysis of pressure transient well-test data is performed to estimate the principal hydrological parameters of the geothermal system around the well(s) being studied. It actually constitutes modelling, or simulation of the pressure transient data by the calculated pressure changes in a relevant model, driven by a given mass extraction from a production well or injection into a reinjection well. Geothermal pressure transient analysis is discussed in detail by Bödvarsson and Witherspoon (1989) and Grant and Bixley (2011).

The main reservoir and well parameters estimated through pressure transient analysis are the following (see also section 3.2):

(a) Formation transissivity or permeability-thickness defined as $\boldsymbol{T = kh/\mu}$ (or $\boldsymbol{kh\rho/\upsilon}$) and $\boldsymbol{kh}$, respectively, with $\boldsymbol{k}$ the formation permeability, $\boldsymbol{h}$ the reservoir thickness, $\boldsymbol{\mu}$ and $\boldsymbol{\upsilon}$ the dynamic and kinematic viscosity of the fluid, respectively, and $\boldsymbol{\rho}$ the fluid density.
(b) Formation storage coefficient defined as $\boldsymbol{S = sh}$ (or $\boldsymbol{shg}$), with $\boldsymbol{s}$ the storativity of the geothermal reservoir involved, $\boldsymbol{h}$ its thickness again and $\boldsymbol{g}$ the acceleration of gravity. The storativity (with units kg/(m^{3}Pa)) describes the storage capacity per unit reservoir volume and depends on rock and fluid/steam compressibility, free surface mobility or phase change activity (two-phase storativity).
(c) Skin factor of the well, which describes an additional pressure drop next to a well due to so-called wellbore damage, often caused by clogging of formation pore-space by drilling mud. A negative skin factor, however, reflects a well with stimulated near-well permeability.
(d) Wellbore storage capacity, which simply depends on wellbore volume and the well-fluid compressibility.

Axelsson (2012a) as well as Grant and Bixley (2011) discusses permeability and storage capacity in detail. The permeability of the reservoir rock reflects the flow resistance of the flow paths in the rock (fractures and pores) and is the reservoir property that most greatly influences the reservoir response to production. The reservoir fluid-flow may in most cases be described by Darcy's law, which relates the underground fluid-flow with the pressure gradient and permeability. Storage describes the ability of a reservoir to store fluid or release it in response to an increase or lowering of pressure. The storativity gives the mass of fluid that is stored (released) by a unit volume of a reservoir as a result of a unit pressure increase (decrease). Even though storativity is a function of reservoir porosity different kinds of reservoirs have different storage mechanisms:

i. The storativity of confined liquid dominated reservoirs (i.e. not connected to shallower hydrological systems) is controlled by water and rock compressibility.
ii. The storativity of unconfined (free-surface) liquid dominated reservoirs is controlled by free-surface lowering, in the long-term.
iii. The storativity of dry-steam reservoirs (rare in reality) is controlled by the compressibility of dry steam, which is much larger than the compressibility of liquid water.
iv. The storativity of two-phase (boiling) reservoirs depends only weakly on porosity, but is controlled by the phase change resulting from the pressure change. When pressure increases some steam condenses allowing the rock to store more fluid. In addition the heat released during the process heats up the rock surrounding the pores and fractures of the rock. Note that two-phase storativity doesn't depend on compressibility at all.

It should be noted that storativity varies by several orders of magnitude between different kinds of reservoirs, compressibility-storativity (i) being the smallest and two-phase storativity (iv) being the greatest.

The basic differential equation, which is used in geothermal reservoir physics to evaluate the mass-transfer in models of geothermal reservoirs as well as estimate reservoir pressure changes, is the so-called *pressure diffusion equation.* It is derived by combining the conservation of mass (involves storativity) and Darcy's law for the mass flow, which in fact replaces the force balance equation in fluid mechanics. This results in:

$$s\frac{\partial p}{\partial t} = \nabla \cdot \left(\frac{k}{\upsilon}\nabla p\right) - f(x,y,z,t) \qquad (5)$$

with p the reservoir pressure, υ the kinematic viscosity of the reservoir fluid and f a mass source density simulating mass extraction from wells as well as injection into reinjection wells. By defining the geometry of a problem, and prescribing boundary- and initial conditions, a mathematical problem has been fully defined (i.e. a model). Theoretically a solution to the problem will exists, which can be used to calculate pressure changes and flow in the model, e.g. for pressure transient test analysis.

The pressure diffusion equation discussed shows what role each of the key parameters, permeability and storativity, play in overall pressure variations and fluid flow. In general it can be stated that permeability controls how great pressure changes are and that storativity controls how fast pressure changes occur and spread.

It should be kept in mind that permeability and porosity of geothermal reservoirs is both associated with the rock matrix of the system as well as the fissures and fractures intersecting it. Overall permeability in geothermal systems is usually dominated by fracture permeability with the fracture permeability commonly being of the order of 1 mD (milli-Darcy) to 1 D (Darcy) while matrix permeability is much lower or 1 μD (micro-Darcy) to 1 mD. Yet fracture porosity is usually of the order of 0.1 – 1% while matrix porosity may be of the order of 5 – 30% (highest in sedimentary systems). Therefore, fissures and fractures control the flow in most geothermal systems while matrix porosity controls their storage capacity. It should also be mentioned that in more complex situations permeability can be anisotropic and needs to be represented by a tensor in equation (5).

The pressure diffusion equation is in fact a parabolic differential equation of exactly the same mathematical form as the heat diffusion (conduction) equation. Therefore, the same mathematical methods may be used to solve these equations (see e.g. Carslaw and Jaeger, 1959). Pressure diffusion is, however, an extremely fast process compared to heat conduction. Strictly speaking, Darcy's law, and consequently the pressure diffusion equation, apply only to porous media such as sedimentary rocks. Yet in most cases fractured reservoirs behave hydraulically as equivalent porous media. This is because how fast the pressure diffusion process is and how rapidly pressure changes diffuse throughout a reservoir. The fractured nature is only relevant on a much smaller spatial and temporal scale. The fractured nature of most geothermal reservoirs can't be neglected when dealing with heat transfer, however (see Chapter 5).

Various solutions to the pressure diffusion equation, for corresponding models, provide the basis for the different tools of geothermal reservoir physics, or engineering. This includes models used to interpret well-test data such as the well-known Theis model (see later). Many such models actually originate from ground-water hydrology or petroleum reservoir engineering, where Darcy's law and the pressure diffusion equation are also applicable.

The permeability-thickness and storage coefficient are estimated through an analysis of pressure transients measured during different kinds of well-tests, ranging from very short step-rate injection or production tests, via longer production (discharge or pumping), pressure build-up and interference tests to long-term (months – years) reservoir testing, often involving several wells. In the case of completion well-tests (Section 3.2) pressure transient analysis is a more accurate analysis than involved in the simple estimation of an injectivity/productivity index. The same analysis methods (actually models) can also be used to analyse data from the longer transient well tests.

The analysis (or modelling) methods most often applied in the geothermal industry have been inherited from groundwater science (they have also been adopted by petroleum reservoir engineering). These classical methods will not be discussed in detail here but instead the reader is referred to the works by Bödvarsson and Witherspoon (1989) and Grant and Bixley (2011). The foundation of the methods is the

Theis model, a sketch of which is presented in Figure 5, along with sketches of a few variants of the basic model. The Theis model comprises a model of a very extensive isotropic, homogeneous and horizontal permeable layer of constant thickness, confined at the top and bottom, with two-dimensional, horizontal flow towards a producing well extending through the layer.

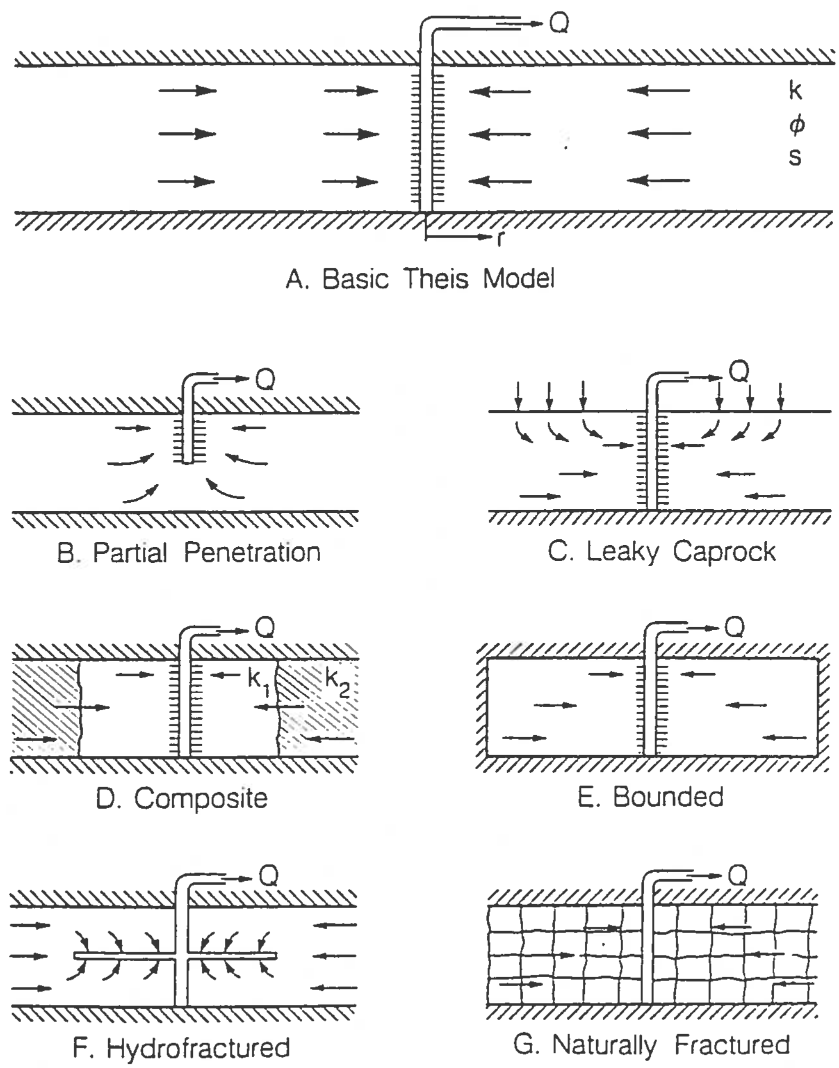

FIGURE 5: A sketch of the basic Theis-model (top) used to analyse pressure transient well-test data along with several variants of the basic model (Bödvarsson and Whiterspoon, 1989)

Well-test data are analysed on basis of the Theis model, and its variants, by fitting the pressure response of the model to observed pressure response data. Consequently the parameters of the model provide an estimate of the parameters of the reservoir being tested. Historically this fitting has been done by using semi-logarithmic plots or the type-curve method. The former method is still used as it is quite simple and effective, in spite of simplifying assumptions; Figure 6 shows the calculated responses of the Theis model and its variants in Figure 5, on a semi-logarithmic plot. The type-curve method has been replaced by more modern, computerized fitting, which today is often applied through an inverse approach, automatically yielding best fitting reservoir parameter estimates. The WellTester software (Júlíusson et al., 2008) has e.g. been used extensively to analyse well-test data from geothermal fields in Iceland, as well as from a variety of other geothermal fields worldwide. Various other well-test analysis software are available, both open-source and commercially.

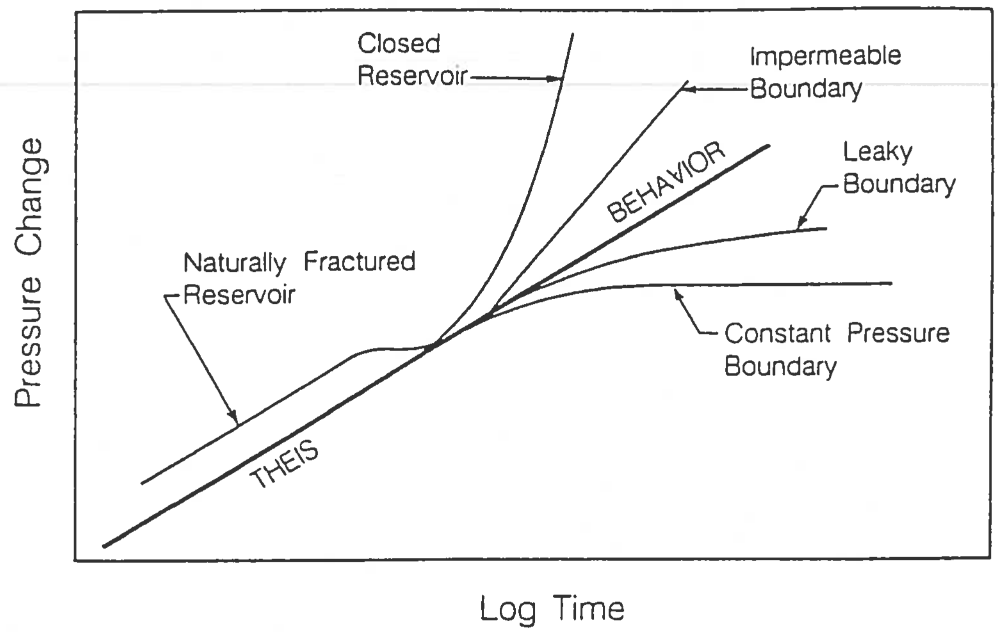

FIGURE 6: Responses of the models in Figure 5 plotted on a semi-logarithmic plot (linear pressure change vs. logarithmic time) demonstrating the linear behaviour, which is the basis of the semi-logarithmic analysis method (Bödvarsson and Whiterspoon, 1989)

Figure 7 shows one of the first examples of the results of computerized fitting of step-rate injection data, from a well drilled into the Krafla volcanic geothermal system in Iceland. It may be mentioned that today combined fitting of the pressure transients and their derivative (derivative analysis) is increasingly being used. Figures 8 and 9 present the results of such an analysis for a high-temperature geothermal production well in the Hengill geothermal region of SW-Iceland, with Figure 8 presenting the pressure transient data collected during a step-rate injection test and Figure 9 a comparison between the corresponding observed and simulated data for one of the steps.

Figures 10 – 12 present two other examples of the analysis, or simulation, of pressure transient data, both involving interference tests during which mass is produced from a certain production well and the resulting pressure transients (interference) observed in a separate monitoring well. Such tests provide the most accurate estimates of the permeability-thickness and storage coefficient, as the analysis of single well pressure transient data doesn't yield unique estimates of the storage coefficient, in addition to the fact that interference tests are generally longer than completion well-tests, providing estimates of reservoir parameters over considerably larger reservoir volumes than the latter. Figures 10 and 11 present data collected during an interference test conducted in the Kawerau geothermal field in New Zealand and Figure 12 presents an interference test example from the Oguni geothermal field in Japan.

The same applies to longer term well-testing, such as discharge testing, as to interference testing (see above). Their analysis also yields estimates of permeability-thickness and storage coefficient, estimates which should be representative for larger reservoir volumes than estimates based on step-rate well-test data, because of the much longer time scale involved. In addition discharge testing is performed at reservoir temperature conditions instead of lower temperature conditions, with an associated viscosity ambiguity, as during step-rate testing.

It should also be stressed that the analysis method for geothermal well-test data reviewed above (Theis model) is based on particular, simplifying assumptions, which are not always applicable. This applies e.g. to the assumption of two-dimensional flow, while three-dimensional flow may be important in many geothermal situations. Therefore, the results of geothermal well-test analyses should be viewed with the model applied in mind. In other words the results are actually model-dependent.

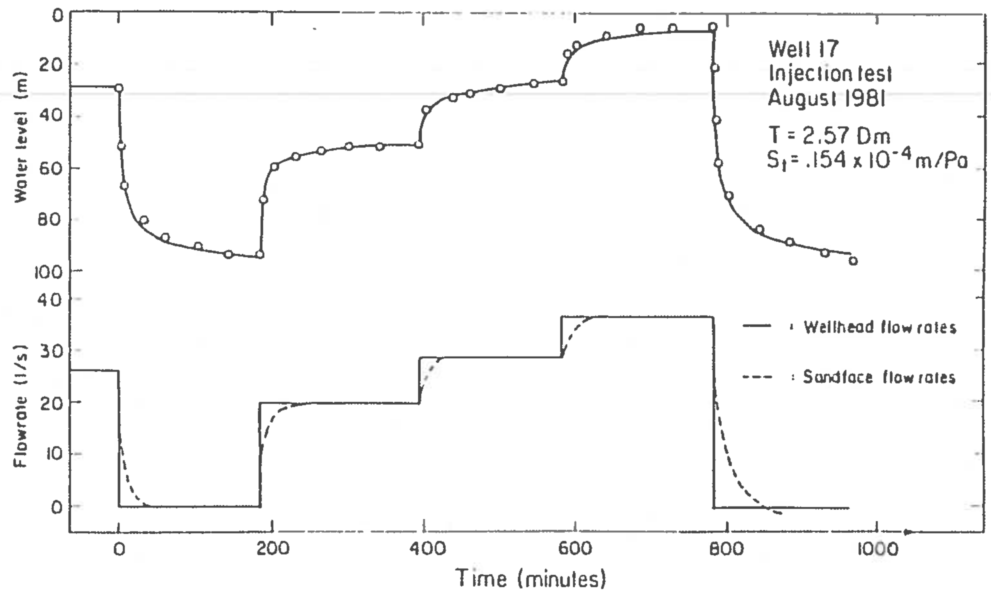

FIGURE 7: An early example of the results of computerized simulation of step-rate injection test data by a Theis-model response (Bödvarsson et al., 1984). Data from a high-temperature production well in the Krafla volcanic geothermal system in N-Iceland

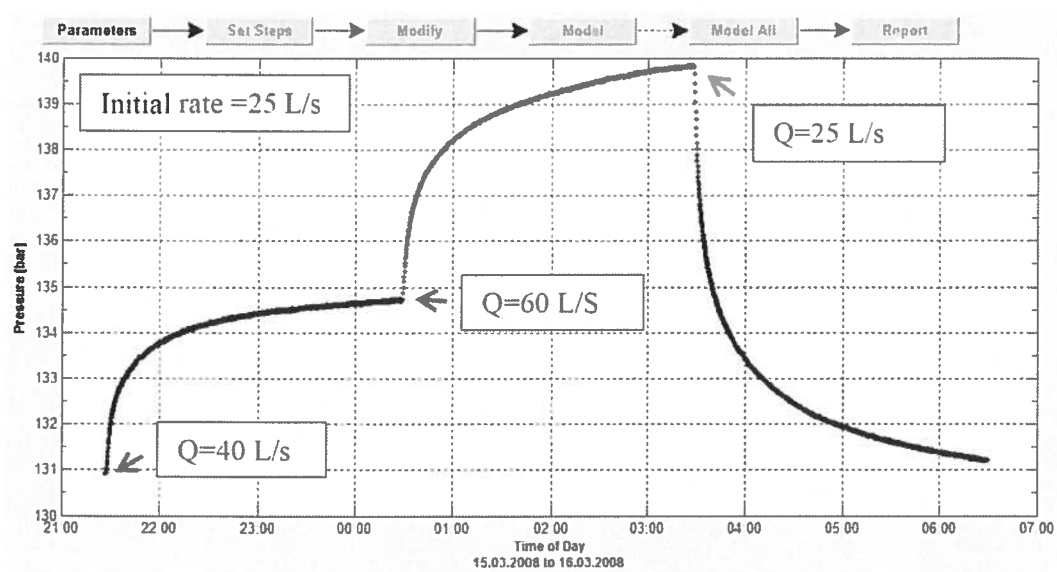

FIGURE 8: Pressure transients measured at 1750 m depth in well HE-41 in the Hengill geothermal region in SW-Iceland during a three-step injection test conducted at the end of drilling (Syed, 2011)

Finally it should be noted that in addition to the conventional reservoir analysis performed on the well data discussed above, the pressure transient data are extremely valuable for the calibration of different kinds of dynamic reservoir models (see Axelsson, 2013), i.e. numerical reservoir models. The simulation of pressure and mass output data by such models is, in effect, pressure transient analysis.

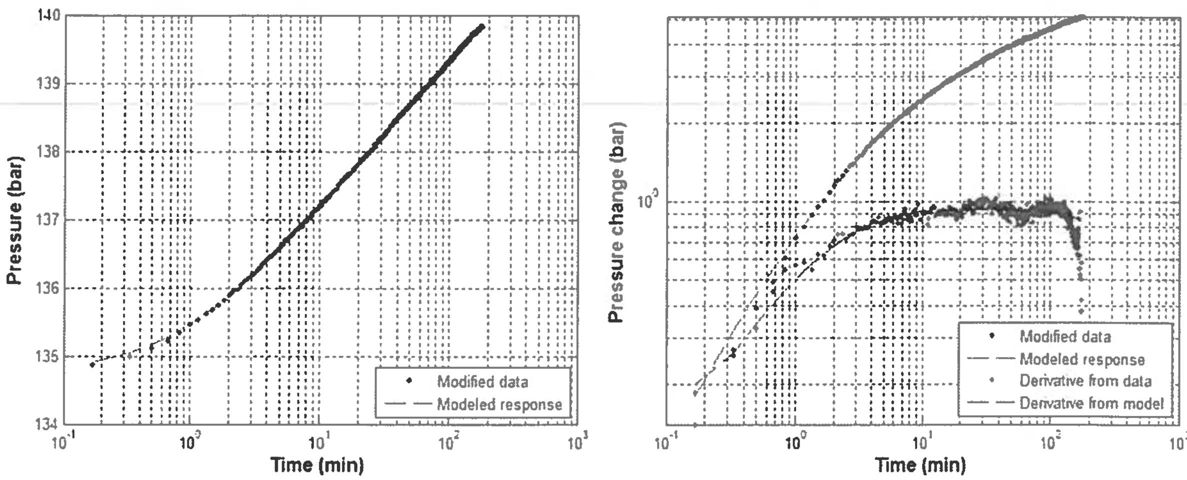

FIGURE 9: Pressure transient data from well HE-41, from the second step of Figure 8, simulated by the WellTester software (see text) and the response of a Theis model variant with a constant pressure boundary (Syed, 2011). The left hand side shows the observed and simulated pressure on a log-linear (semi-logarithmic) scale while the right hand side shows both the observed and simulated pressure, as well as the pressure derivative on a log-log scale. The simulation yields the following parameter estimates: $\boldsymbol{kh} = 1.8\times10^{-12}$ m^2 (1.8 Dm), $\boldsymbol{sh} = 3.6\times10^{-5}$ kg/(Pa·m^2) and skin-factor = -3.5

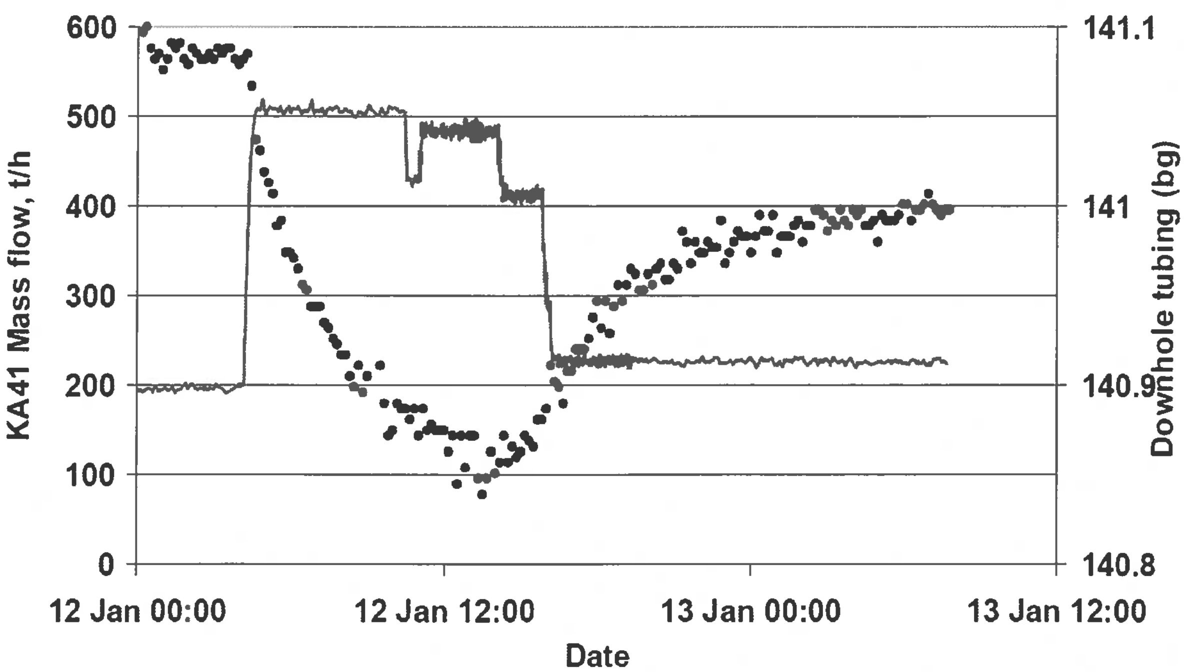

FIGURE 10: Pressure interference test data from the Kawerau geothermal field in New Zealand involving wells KA-41 (production) and KA-6 (pressure observation), see analysis in Figure 11 (Grant and Wilson, 2007)

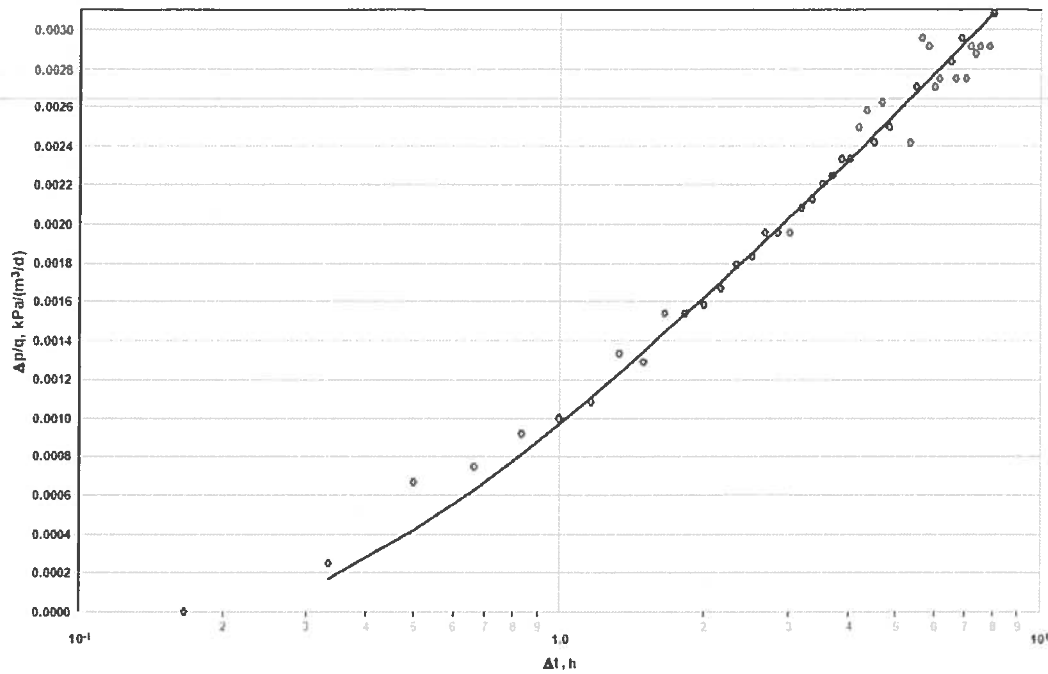

FIGURE 11: Simulation of the pressure response in well KA-6 (see Figure 10) based on the Theis model (Grant and Wilson, 2007). The simulation yields the following parameter estimate: ***kh*** ~ 100×10^{-12} m^2 (~100 Dm) but estimates for the storage coefficient are not reported

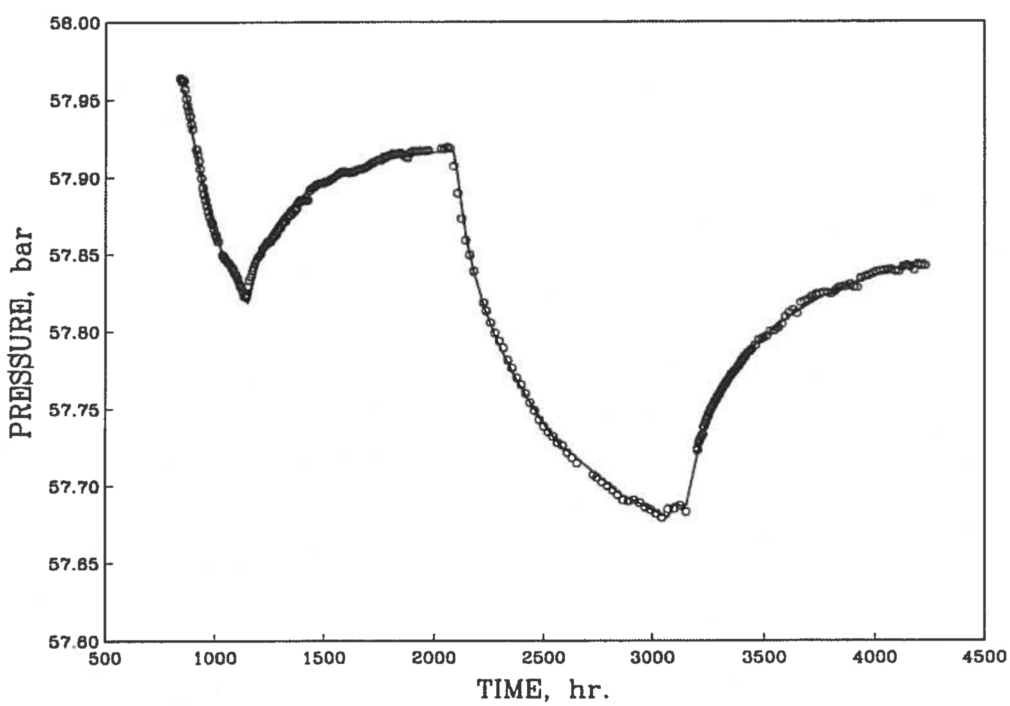

FIGURE 12: Comparison of measured pressure transients (symbols) in slim hole GH-4 in the Oguni geothermal field in Japan with computed response (line), using a Theis model variant with a no-flow boundary, due to production from wells GH-20 and GH-11 (Garg and Nakanishi, 2000). The simulation yields the following parameter estimates: ***kh*** = 150×10^{-12} m^2 (150 Dm) and ***sh*** = 1.6×10^{-3} kg/(Pa·m^2)

5. TRACER TESTING AND ANALYSIS

5.1 General

Tracer testing has become a highly important tool in geothermal research, development and resource management, with its role being most significant in reinjection studies. This is because tracer tests provide information on the nature and properties of connections, or flow-paths, between reinjection and production wells, connections that control the danger and rate of cooling of the production wells during long-term reinjection of colder fluid. Enabling such cooling predictions is actually what distinguishes tracer tests in geothermal applications (studies and management) from tracer tests in ground water hydrology and related disciplines. This information is understandably also important for conceptual model development and revision, when available. This chapter reviews geothermal tracer testing by discussing its general role, by introducing an efficient method of tracer test interpretation and for predicting production well cooling, by presenting a few examples as well as by introducing recent developments and advances in geothermal tracer testing (see also Axelsson, 2012).

Tracer tests are used extensively in surface and groundwater hydrology as well as pollution and nuclear-waste storage studies. Tracer tests involve injecting a chemical tracer into a hydrological system and monitoring its recovery, through time, at various observation points. The results are, consequently, used to study flow-paths and quantify fluid-flow. Tracer tests are, furthermore, applied extensively in petroleum reservoir engineering. The methods employed in geothermal applications have mostly been adopted from these fields.

Tracer testing has multiple applications in geothermal research and management:

1) The main purpose in conventional geothermal development is to study connections between injection and production wells as part of reinjection research and management. The results are consequently used to predict the possible cooling of production wells due to long-term reinjection of colder fluid.
2) In EGS-system development tracer testing has a comparable purpose even though it's rather aimed at evaluating the energy extraction efficiency and longevity of such operations through studying the nature of connections between reinjection and production wells.
3) For general hydrological studies of subsurface flow, such as flow under undisturbed conditions and regional flow.
4) For flow rate measurements in pipelines carrying two-phase water mixtures.

The power of tracer tests in reinjection studies lies in the fact that the thermal breakthrough time (onset of cooling) is usually several orders of magnitude (2–4) greater than the tracer breakthrough time, bestowing tracer tests with a predictive power. This is actually what distinguishes tracer tests in geothermal applications (see 1) and 2) above) from tracer tests in ground water hydrology and related disciplines. Numerous references on tracer tests in geothermal research and development can be found through the web-page of the International Geothermal Association (http://www.geothermal-energy.org), i.e. at World Geothermal Congresses held every 5 years. The reader is also referred to a special issue of the international journal Geothermics devoted to tracer tests (Adams, 2001) and a paper by Axelsson et al. (2005).

Geothermal tracer tests are mostly conducted through wells and can involve (i) a single well injection-backflow test, (ii) a test involving one well-pair (injection and production) as well as (iii) several injection and production wells. In the last setup several tracers must be used, however. The geothermal reservoir involved should preferably be in a "semi-stable" pressure state prior to a test. This is to prevent major transients in the flow-pattern of the reservoir, which would make the data analysis more difficult. In most cases a fixed mass of tracer is injected "instantaneously", i.e. in as short a time as possible, into the injection well(s) in question. Samples for tracer analysis are most often collected from producing wells, while down-hole samples may need to be collected from non-discharging wells. The duration of a tracer test is of course site specific and hard to pinpoint beforehand. The same applies to sampling plans, even though an inverse link between required sampling frequency and time passed can often be assumed (Axelsson et al., 2005).

The tracer selected needs to meet a few basic criteria: It should (a) not be present in the reservoir (or at a concentration much lower than the expected tracer concentration), (b) not react with or absorb to reservoir rocks (see however discussion on reactive tracers below), (c) be thermally stable at reservoir conditions, (d) be relatively inexpensive, (e) be easy (fast/inexpensive) to analyse and (f) be environmentally benign. In addition the tracer selected must adhere to prevailing phase (steam or water) conditions. The following are the principal tracers used in geothermal applications (not a complete list):

Liquid-phase tracers:

- Halides such as iodide (I) or bromide (Br);
- Radioactive tracers such as the isotopes iodide-125 (^{125}I) and iodide-131 (^{131}I);
- Fluorescent dyes such as fluorescein and rhodamine;
- Aromatic acids such as benzoic acid;
- Naphthalene sulfonates.

Steam-phase tracers:

- Fluorinated hydrocarbons such as R-134a and R-23;
- Sulphur hexafluoride (SF_6).

Two-phase tracers:

- Tritium (^3H);
- Alcohols such as methanol, ethanol and n-propanol.

Sodium-fluorescein has been used successfully in numerous geothermal fields, both low- and high-temperature ones (Axelsson et al., 2005). It meets most of the criteria listed above and, in particular, can be detected at very low levels of concentration (10-100 ppt). In contrast the detection limit of halides is several orders of magnitude higher.

The main disadvantage in using fluorescein is that it decays at high temperatures, a decay which becomes significant above 200°C. Therefore new tracers with higher temperature-tolerance, but comparable detection limits, have been introduced, in particular several polyaromatic sulfonates (Rose et al., 2001). These are increasingly being used in geothermal applications. Having several comparable tracers also enables the execution of multi-well tracer tests. Rose et al. (2001) present the temperature-tolerance of several of these compounds, which in some cases exceeds 300°C.

Radioactive materials are also excellent tracers since they are detectable at extremely low concentration (Axelsson et al., 2005). Their use is limited by stringent transport, handling and safety restrictions, however. When selecting a suitable radioactive tracer their different half-lives must be taken into account. Iodide-125 and iodide-131 have half-lives of 60 and 8.5 days, respectively, for example.

It should be mentioned that for flow-rate measurements in two-phase pipelines (Hirtz et al., 2001) fluorescein or benzoic acid are commonly used for the liquid phase. Naphthalene sulfonates are also promising as such. Steam-phase measurements are commonly done using SF_6 or a suitable alcohol.

Special techniques, of differing complexity, have been developed for sampling and analysing geothermal tracers. A discussion of these is beyond the scope of this paper, however.
Figures 13 – 15 show three examples of the results of tracer tests conducted in geothermal systems of quite contrasting nature, also presented by Axelsson (2012). These are just presented as concise examples, without specific field details. Two more examples, with interpretation results, are presented below.

Figure 13 shows the tracer recovery during an unusually long tracer test conducted in the Hofsstadir low-temperature (reservoir temperature 85-90°C) geothermal system in W-Iceland already mentioned twice in this paper. The test involved tracer injection into an operating reinjection well about 1200 m from the production well. The relatively slow recovery indicates that reinjection induced cooling will be limited. This awaits confirmation through comprehensive interpretation and modelling.

Figure 14 shows the tracer recovery during a tracer test conducted in the Krafla high-temperature (reservoir temperature 200-400°C) geothermal system in N-Iceland. The test involved tracer injection into a temporary reinjection well about 200 m from a production well. The relatively rapid recovery was interpreted as indicating a considerable danger of cooling of the production well. Therefore the reinjection well was abandoned as such.

The third example involves tracer tests conducted at the Soultz EGS site in N-France during stimulation and testing between 2000 and 2005 (Sanjuan et al., 2006). The tests involved 4 wells ranging in depth from 3600 to 5300 m. A few different tracers very used, including fluorescein and some naphthalene sulfonates. Figure 15 shows the recovery during the test between wells GPK-3 and GPK-2 separated by 650 m, in which fluorescein was successfully used. It showed the most direct connection in the system.

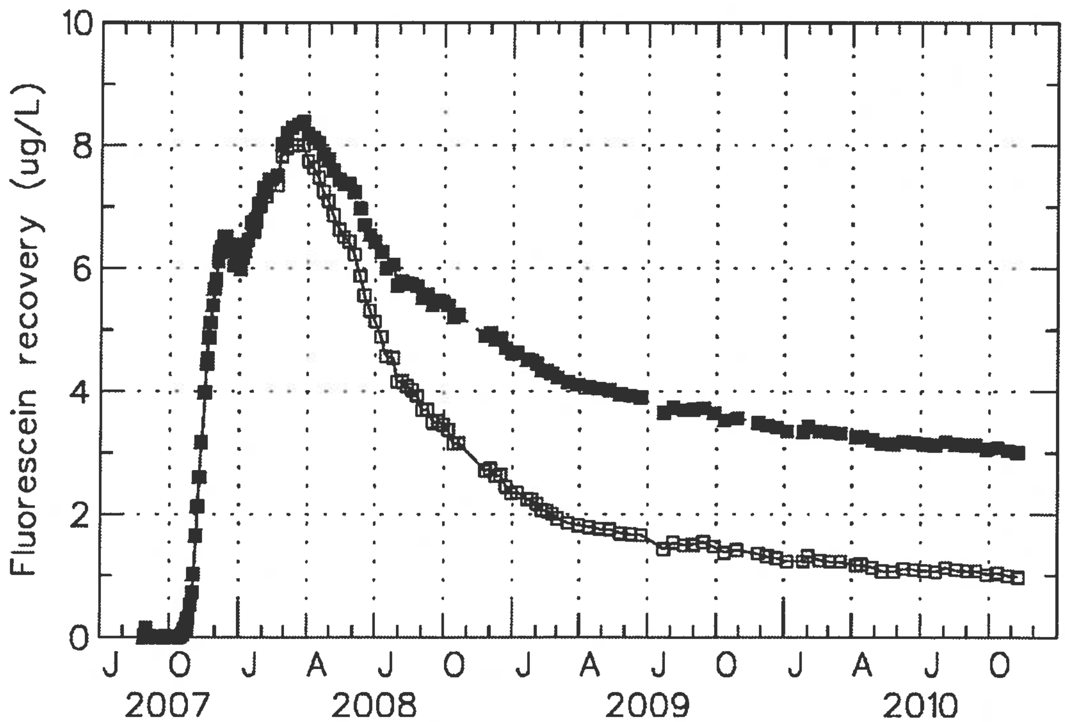

FIGURE 13: Fluorescein recovery in production well HO-1 in the Hofsstadir low-temperature system in W-Iceland, following the injection of 10 kg of the tracer into reinjection well HO-2 (from Axelsson, 2011). The test lasted 3.5 years. The lower curve shows the recovery corrected for the tracer being reinjected (recirculated) after production from HO-1. About 70% of the tracer was recovered during the test

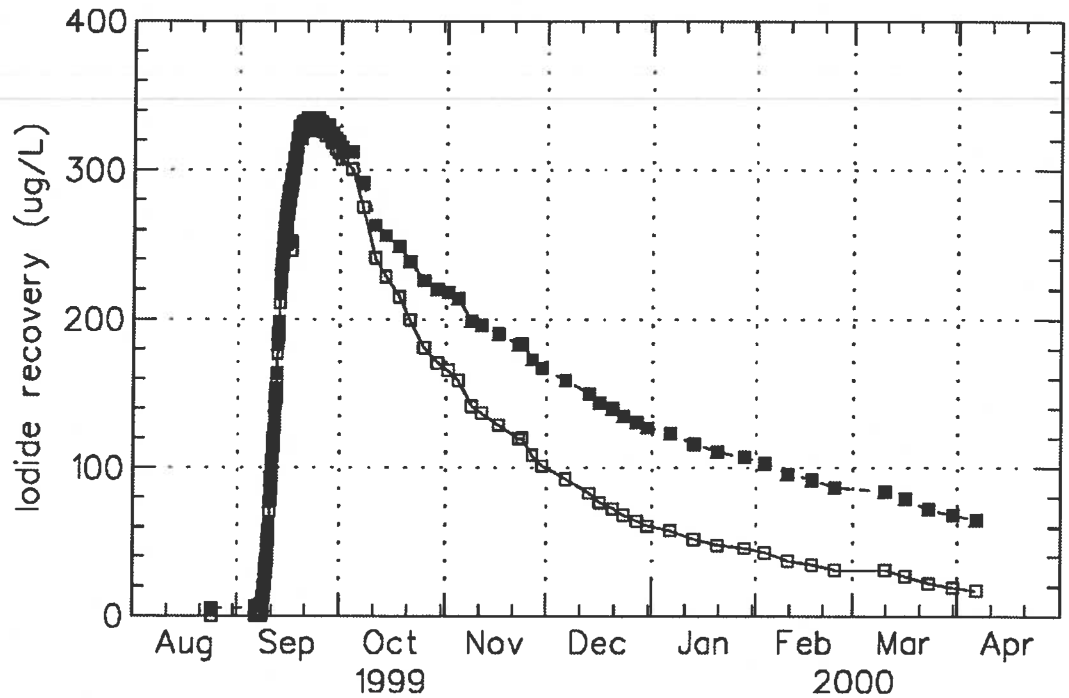

FIGURE 14: Iodide recovery in production well K-21 in the Krafla high-temperature system in N-Iceland, following the injection of 200 kg of KI into well K-22 (from Axelsson, 2011). The test lasted 7 months. The lower curve shows the recovery corrected for the tracer being reinjected (recirculated) after production. About 30% of the tracer was recovered during the test)

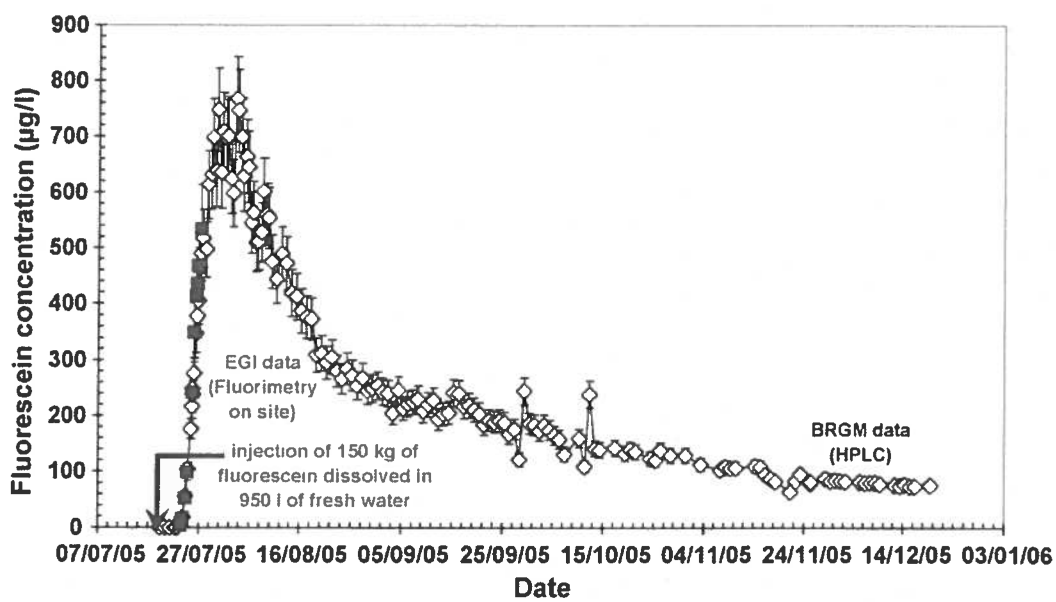

FIGURE 15: Flourescein recovery in well GPK-2 at the Soultz EGS-site in N-France, following the injection of 150 kg of fluorescein into well GPK-3 (figure from Sanjuan et al., 2006). The test lasted 5 months. About 24% of the tracer was recovered during the test

The above are examples of geothermal tracer test data without any quantitative interpretation. Below a specific interpretation method will be presented along with two interpretation examples.

5.2 Interpretation method and examples

Comprehensive interpretation of geothermal tracer test data, and consequent modelling for management purposes (production well cooling predictions), has been rather limited, even though tracer tests have been used extensively. Their interpretation has mostly been qualitative rather than quantitative. Axelsson et al. (2005) present a simple and efficient method that may be used for this purpose. It is based on simple models, which are able to simulate the relevant data quite accurately. They are powerful during first stage analysis, when the utilization of detailed and complex numerical models is not warranted. The more complex models become applicable when a greater variety of data become available that may be collectively interpreted.

The method of tracer test interpretation referred to is conveniently based on the assumption of specific flow channels connecting injection and production wells. It has been used to analyse tracer test data from quite a number of geothermal systems in e.g. Iceland, El Salvador, the Philippines, Indonesia and China and consequently to calculate cooling predictions (Axelsson et al., 2005). It has proven to be very effective. This method is based on simple models, which are nevertheless able to simulate the relevant data quite accurately.

The tracer transport model involved assumes the flow between injection and production wells may be approximated by one-dimensional flow in flow-channels. These flow-channels may, in fact, be parts of near-vertical fracture-zones or parts of horizontal interbeds or layers. The channels may be envisioned as being delineated by the boundaries of these structures, on one hand, and flow-field stream-lines, on the other hand. In other cases these channels may be larger volumes involved in the flow between wells. In some cases more than one channel may be assumed to connect an injection and a production well, for example connecting different feed-zones in the wells involved.

The interpretation method involves simulating tracer return data, such as presented above, on basis of equations presented by Axelsson et al. (2005). The simulation yields information on the flow channel cross-sectional area and dispersivity as well as the mass of tracer recovered through a given channel (equal to, or less than, the mass of tracer injected). In the case of two or more flow-channels the analysis yields estimates of these parameters for each channel. Through the estimates of flow channel cross-sectional area(s) the flow channel pore space volume(s) has (have) in fact been estimated. The tracer interpretation software *TRINV*, included in the *ICEBOX* geothermal software package, can be used for this simulation (Axelsson et al., 2005).

It should be emphasised that this method does not yield unique solutions and that many other models have been developed to simulate the transport of contaminants in ground-water systems, and in relation to underground disposal, or storage, of nuclear waste. Many of these models are in fact applicable for the interpretation of geothermal tracer tests. It is often possible to simulate a given data-set by more than one model; therefore a specific model may not be uniquely validated.

In addition to distance between wells and volume of flow-paths, mechanical dispersion is the only factor assumed to control the tracer return curves in the method presented above. Retardation of tracers by diffusion from the flow-paths into the rock matrix is neglected. It is likely to be negligible in fractured rock except when fracture apertures are small, flow velocities are low and rock porosity is high.

The main goal of geothermal tracer testing is to predict thermal breakthrough and temperature decline during long-term reinjection, or the efficiency of thermal energy extraction in EGS operations, as already stated. This is dependent on the properties of the flow-channel(s) involved, but not uniquely determined by the flow-path pore-space volume (Axelsson et al., 2005). The heat transfer (cooling/heating) mainly depends on the surface area and porosity of the flow-channel(s). Therefore, some additional information on the flow-path properties/geometry is needed, i.e. geological or geophysical in nature (see also later discussion of recent advances).

To deal with this uncertainty heat-transfer predictions may be calculated for different assumptions on flow-channel dimensions, at least for two extremes. First for a small surface area, or pipe-like, flow channel, which can be considered a pessimistic model with minimal heat transfer. Second a large surface area flow channel, such as a thin fracture-zone or thin horizontal layer, which can be considered an optimistic model with effective heat transfer. Additional data, in particular data on actual temperature changes, or data on chemical variations, if available may be used to constrain cooling predictions.

Figures 16 – 18 present examples of the results of geothermal tracer test analysis using the interpretation method discussed above. The results are only presented briefly here with some numerical findings presented in figure captions. More details can be found in the references cited. Figure 16 shows the fluorescein recovery through a production well in the Laugaland low-temperature geothermal system (reservoir temperature 90-100°C) in N-Iceland, conducted in 1997, simulated by the method presented above (Axelsson et al., 2001). This was during initial reinjection testing in the field, since then reinjection has been part of the management of the system. Figure 17 shows production temperature predictions calculated by a pessimistic model based on the tracer recovery simulation presented in Figure 16. They show that the long-term cooling of the well in question should be minimal, in particular in view of the considerable increase in productivity of the Laugaland system when reinjection is applied (Axelsson et al., 2001).

The final interpretation example is from the Los Azufres high-temperature geothermal system (reservoir temperature ~280°C) in the state of Michoacán in Mexico. It involves interpretation of a tracer test conducted in late 2006 (Figure 18) in which SF_6 was used due to the fact that a steam zone has developed in the system and that production wells involved (NE-part of the field) produce mostly steam (Molina-Martínez and Axelsson, 2011). Cooling predictions based on the interpretation indicate that well AZ-5 may cool as much as 14°C during 30 years of 8 kg/s reinjection into AZ-64 (compared with 21 kg/s production from AZ-5), cooling which is probably not acceptable.

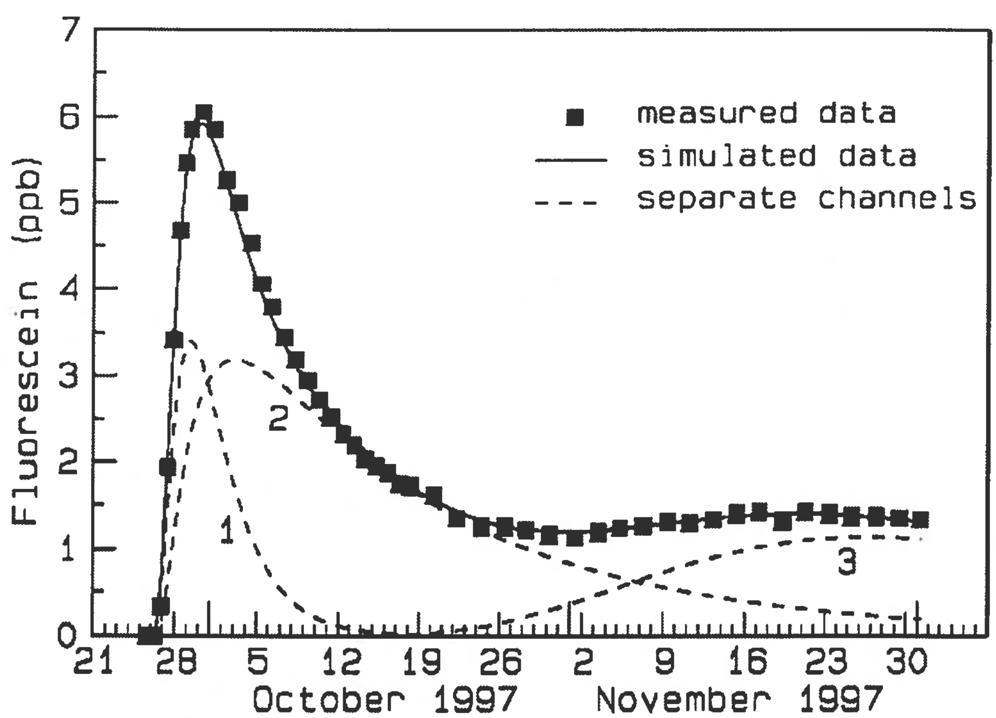

FIGURE 16: Observed and simulated (three flow channels) fluorescein recovery in well LN-12 at Laugaland in N-Iceland during a tracer test in 1997 (figure from Axelsson et al., 2001). Spent geothermal fluid was reinjection into well LJ-08 and production was from well LN-12 about 300 m away. According to the simulation only about 6% of the tracer injected is recovered through this well and the combined flow-channel volume is estimated as 20,000 m^3, assuming 7% porosity

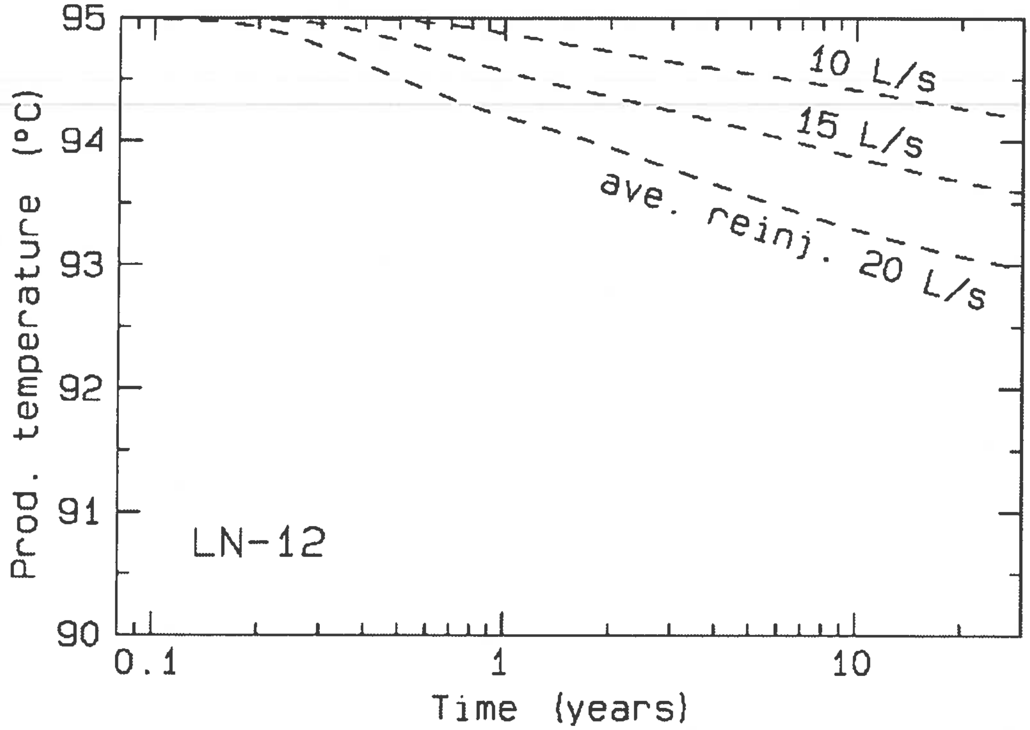

FIGURE 17: Estimated production temperature decline of well LN-12, due to flow through the three channels simulated (Figure 12), for three cases of average long-term reinjection into well LJ-8 and an average long-term production rate of 40 L/s (figure from Axelsson et al., 2001)

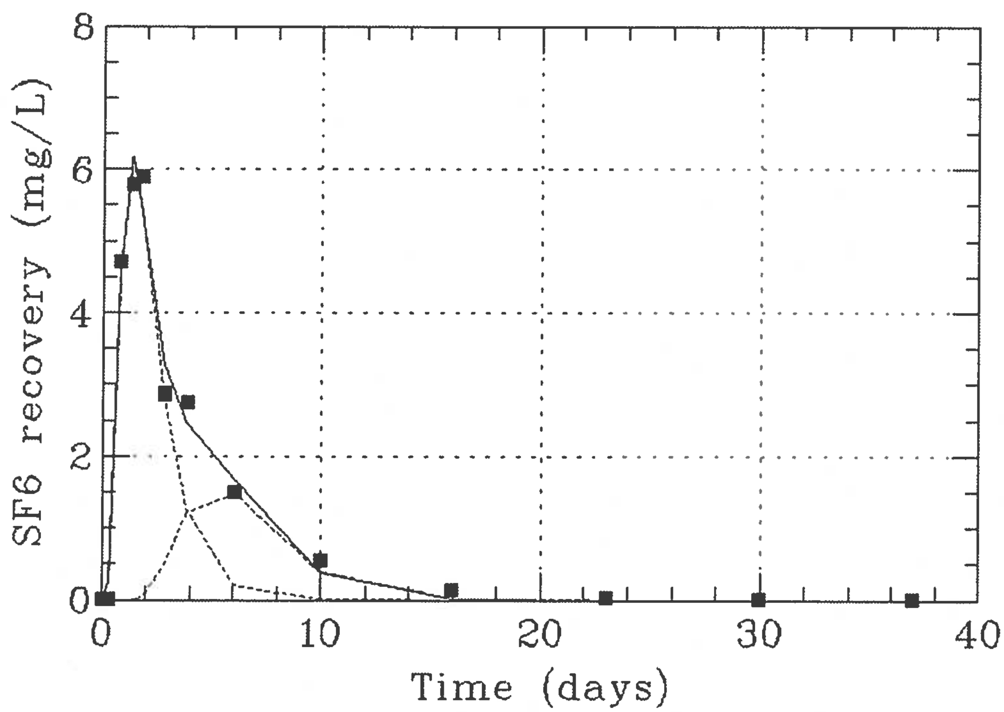

FIGURE 18: Observed and simulated (two flow channels) SF_6 recovery in well AZ-5 in the Los Azufres high-temperature field in Mexico, following injection into well AZ-64 200 m away (Molina-Martínez and Axelsson, 2011). The very rapid recovery is attributed to steam-phase transport. Almost 50% of the tracer was recovered through a combined flow channel volume of 200,000 m^3 (~10% porosity)

5.3 Recent advances

The main uncertainty in reinjection operations and EGS development involves the heat-transfer efficiency of flow-channels between reinjection and production wells. This depends on the surface area of the flow-channels, information which conventional tracer testing using conservative tracers does not yield. Therefore, emphasis has been placed on the introduction of reactive tracers, in particular in EGS-research, as they can provide this information. This includes high-tech tracers such as nano-particles and quantum-dots (see e.g. Rose et al. (2011). By applying two tracers, one conservative and the other reactive, it should be possible to estimate both the flow-channel pore-space volume and its surface area (the transport of the reactive tracer depends on the available surface area as well as the volume).

6. CONCLUSIONS AND RECOMMENDATIONS

This paper reviews the main methods of testing geothermal reservoirs through wells, generally termed well-testing. Both pressure transient testing, which is one of the main tools of geothermal reservoir physics/engineering, and tracer testing are reviewed. Through pressure transient well testing and consequent pressure transient analysis the main reservoir parameters, such as permeability-thickness and storage coefficient, can be estimated along with reservoir boundary conditions (if a test is sufficiently long-lasting). Such estimates consequently provide key information for conceptual model development and revision.

Pressure transient analysis is performed on the basis of appropriate reservoir models and it involves, in fact, model simulation of the pressure transient data collected. Various models are available for this purpose, but most often the well-known Theis model, or variants of that model, are used. Using the Theis model makes it possible to compare results for different wells as well as different geothermal systems, yet the Theis model is based on quite specific assumptions that may not be correct, in particular regarding the reservoir and flow-field geometry (two-dimensional and radial). Therefore, the results of geothermal well-test analyses should be viewed with the model applied in mind. In other words the results are actually model-dependent. Employing different models is therefore recommended during pressure transient analysis, with the conceptual model of the system in question in mind. Using different variants of the Theis model (see above), and selecting the one that best fits the data, is a step in the right direction.

Well tests range from very short step-rate injection or production tests at well completion, via longer production (discharge or pumping), pressure build-up and interference tests to long-term (months – years) reservoir testing, often involving several wells. The longer the test the more valuable the information derived is, because an increasingly larger volume of the reservoir being tested is sensed with increasing test length. Long-term monitoring (mass extraction and pressure in particular) actually constitutes extra long-term pressure transient testing, albeit under uncontrolled conditions (often variable mass extraction). Long-term interference testing provides by far the most important information, as the analysis of single well tests doesn't yield fully unique parameter estimates.

Tracer testing plays an important role in geothermal research and management, in particular concerning heat-transfer efficiency in reinjection operations and EGS development. Advances have been made in the introduction of new tracers, which both add to the multiplicity of high-sensitivity tracers available as well as being increasingly temperature tolerant. But the geothermal industry needs to follow advances in other disciplines and adopt those which are beneficial. This applies, in particular, to advances in modelling of tracer return data, which has been limited so far, especially modelling of reactive tracer data, which can yield information on flow-channel surface areas in addition to their volumes.

ACKNOWLEDGEMENTS

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LOGGING, TESTING AND MONITORING GEOTHERMAL WELLS

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ABSTRACT

Wells or boreholes are essential components in both geothermal research and utilization as they enable a drastic increase in geothermal energy production beyond natural out-flow as well as providing access deep into the systems, not otherwise possible. Wells also play a vital role in all geothermal reservoir physics (also called reservoir engineering) research, which would be particularly ineffective without the access into geothermal systems provided by wells. During drilling the main reservoir physics research is performed through logging of different parameters as functions of depth, with temperature and pressure being of particular importance. At well completion the most important reservoir physics research is step-rate well-testing, either through injection or production, which enables the first estimates of well and reservoir properties. Reservoir physics research is also conducted in association with well stimulation at the end of drilling. Repeated temperature logging aimed at estimating undisturbed reservoir temperature and pressure is the key research performed during well warm-up. Monitoring of mass and energy output along with logging down-hole pressure transients is the most important reservoir physics research conducted during output testing of geothermal wells along with pressure recovery logging after wells are shut in and interference monitoring. Much of the same reservoir physics research is also conducted in reinjection wells during drilling and following completion. All of the above provides vital information for reservoir assessments of the geothermal resource in question, but the most important data for that purpose actually comes from monitoring of energy production and the consequent response of the geothermal system during long-term (several years) utilization. The reservoir physics data collected during these phases also plays an essential role in the calibration of various reservoir models.

1. INTRODUCTION

Wells or boreholes are vital components in both geothermal research and utilization, since they provide essential access for both energy extraction and information collection, as already mentioned. The breakthrough of increased geothermal utilization and improved understanding of geothermal systems during last century coincided in fact with geothermal wells becoming the main instruments of geothermal development. Wells enable a drastic increase in geothermal energy production, compared to natural out-flow, and provide access deep into the systems, not otherwise possible. The key to the successful drilling of any type of geothermal well is correct siting and design of the well based on a clear definition and understanding of the drilling target aimed for, founded on all information available at any given time. This is best achieved through a comprehensive and up-to-date conceptual model incorporating, and unifying, the essential physical features of a geothermal system. Geothermal drilling targets and well siting are discussed in a separate lecture at this short course (Axelsson and Franzson, 2012). The current lecture can be considered a sequel to that lecture.

Geothermal wells play a variable role during both development of a geothermal resource and during their utilization. The main roles are either as temperature gradient, exploration, appraisal, production, step-out, make-up, reinjection or monitoring wells. Wells also play an essential role in all geothermal reservoir physics research. Such research would be particularly ineffective without the access into geothermal systems wells provide. Geothermal reservoir physics, commonly also called geothermal reservoir engineering, is the scientific discipline that deals with mass and energy transfer in geothermal systems and geothermal wells. It attempts to understand and quantify this flow along with accompanying changes in reservoir conditions, in particular those caused by exploitation. During the exploration stage of a geothermal resource research focuses on analysis of surface exploration data; mainly geological, geophysical and geochemical data (Axelsson and Franzson, 2012). This emphasis changes to reservoir physics research during development and utilization.

The purpose of geothermal reservoir physics is, in fact, twofold: To obtain information on the nature, reservoir properties and physical conditions in a geothermal system and to use this information to predict the response of reservoirs and wells to exploitation. Based on the latter the energy production capacity of a geothermal resource can be assessed. Response predictions also aid in the different aspect of the management of geothermal resources during utilization (Axelsson, 2008). Geothermal reservoir physics emerged as a separate scientific discipline in the 1970s even though some isolated studies of the physics of geothermal systems had been conducted before that in countries like Iceland, New Zealand and the USA (Grant et al., 1982). Geothermal reservoir engineering, as well as geothermal technology in general, draws heavily from the theory of ground water flow and petroleum reservoir engineering, the former having emerged in the 1930's. However, geothermal reservoirs are in general considerably more complex than ground-water systems or petroleum reservoirs. The different aspects of geothermal reservoir physics are e.g. discussed by Grant et al. (1982), Bödvarsson and Witherspoon (1989) and Grant and Bixley (2011).

Geothermal wells can be classified as one of three principal types:

(a) Liquid-phase low-temperature wells, which produce liquid water at well-head (pressure may be higher than atmospheric, however).
(b) Two-phase high-temperature wells where the flow from the feed-zone(s) is liquid or two-phase and the wells produce either a two-phase mixture or dry-steam.
(c) Dry-steam high-temperature wells where the flow from the feed-zone(s) to the well-head is steam-dominated.

In the liquid-phase and dry-steam wells the inflow is single phase liquid water or steam, respectively, while two-phase wells can be furthermore classified as either liquid or two-phase inflow wells. In multi feed-zone two-phase wells one feed-zone can even be single-phase while another one is two-phase.

This paper reviews the main reservoir physics research conducted through geothermal wells, in particular logging, well-testing and monitoring. It starts out by discussing logging of wells during drilling and the research conducted at the end of drilling, during well completion. After that it reviews logging and research conducted during the warm-up phase following drilling and during output testing. Subsequently the paper discusses briefly the monitoring of geothermal reservoirs during utilization. The paper is concluded by general conclusions and recommendations. The reader is also referred to a paper by Steingrímsson and Gudmundsson (2006) dealing with geothermal well research during and after drilling.

2. RESERVOIR PHYSICS RESEARCH DURING DRILLING

2.1 During drilling

The principal research conducted during drilling of geothermal wells is achieved through logging of the wells, often called wireline logging. This involves measuring various contrasting, partly unrelated, parameters for different purposes as a function of depth. Some of these are drilling technology related, others for logging geological parameters and still others for reservoir physics purposes. The following are the main logging methods applied during geothermal well drilling:

(A) Caliper and cement bond logging aimed at measuring variations in well diameter and assessing the integrity of casing cementing. The former is, in particular, used to measure wash-out intervals, either in soft formations or at major feed-zones. The latter method is used to evaluate how well casings are bonded to cement injected into the annulus between the casings and the rock formations outside the wells, in particular. These types of logs are discussed in more detail by Steingrímsson (2011a). In addition imaging of casings and other parts of wells by video cameras is increasingly being used, in particular at relatively shallow levels (down to several hundred metres), to study casing damages, formations and sometimes feed-zones (examples will be presented at this short course).

(B) Geophysical logging aimed at estimating different physical properties of the rock formations intersected by the well. This type of logging also supplements drill cutting analysis, in particular for depth intervals where drill cuttings aren't available, e.g. due to total circulation loss. Such logs include various types of resistivity logs, neutron-neutron logs aimed at estimating water content (dependent on porosity), gamma-gamma logs aimed at estimating rocks density, sonic logs aimed at estimating seismic wave velocity and natural gamma ray logs, which can be used to distinguish certain types of formations. These types of logs are discussed in more detail by Steingrímsson (2011b).

(C) Fracture imaging is increasingly being used to study specific fractures and fracture distribution in wells. The method most often applied is televiewer logging, which produces an acoustic "picture" of the walls of a well, where fractures can be easily mapped and their strike and dip determined. These provide an extremely valuable addition to other logging, and circulation loss analysis, aimed at understanding feed-zones in wells. Steingrímsson (2011b) also discusses fracture imaging. Figure 1 shows a clear example of a televiewer image of a feed-zone in a geothermal well in Iceland.

(D) Temperature and pressure logging can be viewed as the main reservoir physics logging performed during drilling. These will be discussed in more detail below. In addition spinner logging is often applied to estimate fluid flow in wellbores as well as inflow or outflow through feed-zones.

It may be mentioned in addition that geothermal logging is discussed in depth in an old treatise by Stefánsson and Steingrímsson (1980) as well as by Grant and Bixley (2011).

During the drilling phase of a well temperature and pressure logging has a few different research purposes; firstly to evaluate well conditions regarding the drilling operation itself, secondly to locate feed-zones (inflow or outflow zones) and thirdly to estimate reservoir temperature and pressure. During drilling temperature and pressure are, however, greatly disturbed and it's difficult to estimate reservoir temperature and pressure accurately. Temperature is e.g. always lowered by drilling fluid circulation as well as being often affected by inflow or outflow through feed-zones or internal flow between feed-zones (Figure 2). Undisturbed temperature is sometimes approximated by measuring temperature warm-up during short breaks (sometimes overnight) in the drilling operation, either planned or unplanned. Then the temperature recovery is measured as a function of time at a specific depth (often well bottom) and particular methods, such as the Horner method, used to assess the undisturbed temperature. The application of temperature and pressure logging will be discussed further below.

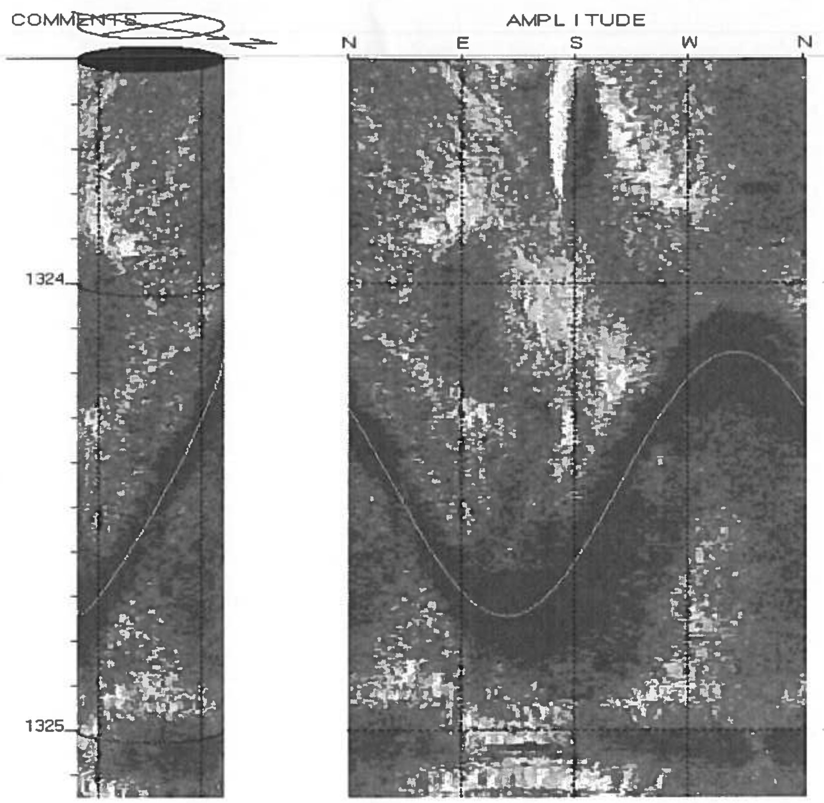

FIGURE 1: An example of a televiewer image of a highly productive, open feed-zone in a geothermal well in Iceland striking NW-SE and dipping 7° from the vertical (Steingrímsson, 2011b)

The instruments used for logging geothermal wells will not be discussed in this paper, but it may be mentioned that most such tools come, or have been adapted, from the petroleum industry. Many such tools have temperature limitations so that high-temperature wells need to be in cooled down conditions (i.e. during drilling) when used, in particular the geophysical logging tools and televiewers. High-temperature tools, such as for logging temperature and pressure, were previously mechanical ones, which could only be used for logging at discrete depths. Now memory tools with continuous recording are mostly used for this purpose. Tools tolerating higher temperature than conventional geothermal logging tools are being developed, however (see e.g. Massiot et al., 2010).

2.2 At completion

At well completion reservoir physics research kicks in at full force, with the main purpose being to assess the result of the drilling operation. If the outcome is deemed satisfactory the drilling operation is stopped, otherwise drilling may be continued to greater depth or a program of well stimulation may be initiated (see later). The main phases of conventional completion program for a geothermal production well are as follows:

(1) Temperature and pressure logging, sometimes accompanied by spinner logging, to evaluated location and relative importance of feed-zones as well as temperature conditions prior to later phases of the completion test (due to temperature limitations of instruments used).
(2) Geophysical logging and fracture imaging of the production part of the well.
(3) Step-rate well-testing; through injection in high-temperature wells or production in low-temperature wells. Pressure (and sometimes temperature) transients measured down-hole.
(4) Temperature and pressure logging is normally performed after, sometimes even during step-rate testing. Spinner logging can be beneficial to assess feed-zones.

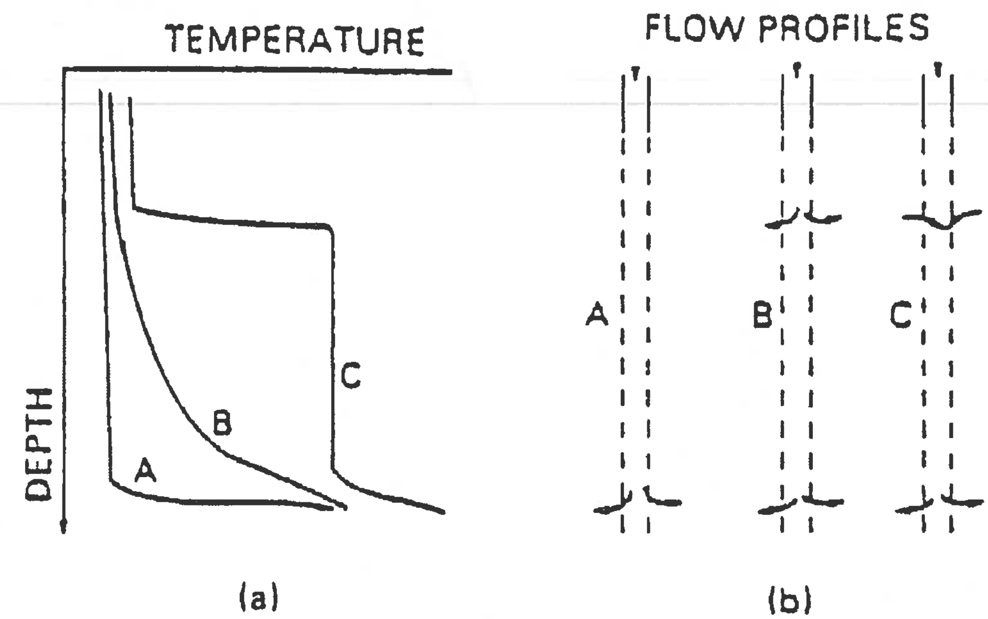

FIGURE 2: A sketch showing typical temperature profiles measured during drilling, the first with one main circulation loss at depth (A), the second with a shallow and deep circulation loss (B) and the third with shallow inflow (because of higher pressure in the loss-zone outside the well), down-flow and deep outflow (Grant et al., 1982)

The purpose of the step-rate well-testing, which is the main reservoir physics research conducted at the end of drilling a well, is to obtain a first estimate of the possible production capacity of a well and to estimate its production characteristics. In the case of high-temperature wells this estimate is only indirect since it's not performed at high-temperature, production conditions. Step-rate well-testing usually lasts from several hours to a few days. The following are the parameters usually estimated on basis of step-rate test data:

(a) Injectivity index, defined as $II = \Delta q/\Delta p$, with Δq the change in flow-rate and Δp the change in down-hole pressure, usually based on measured values at the end of each step. In the case of low-temperature wells tested through production step testing a comparable index is defined, termed productivity index (***PI***). A productivity index is also estimated during production testing of high-temperature wells. This will be discussed later in the paper.
(b) Formation transissivity or permeability-thickness defined as $T = kh/\mu$ (or $kh\rho/\nu$) and kh, respectively, with k the formation permeability, h the reservoir thickness, μ and ν the dynamic and kinematic viscosity of the fluid, respectively, and ρ the fluid density.
(c) Formation storage coefficient defined as $S = sh$ (or shg), with s the storativity of the geothermal reservoir involved, h its thickness again and g the acceleration of gravity. The storativity (with units kg/(m^{3}Pa)) describes the storage capacity per unit reservoir volume and depends on rock and fluid compressibility, free surface mobility or phase change activity (two-phase storativity).
(d) Skin factor of the well, which describes an additional pressure drop next to a well due to so-called wellbore damage, often caused by clogging of formation pore-space by drilling mud. A negative skin factor, however, reflects a well with stimulated near-well permeability.
(e) Wellbore storage capacity, which simply depends on wellbore volume and the well-fluid compressibility.

The injectivity index (as well as the productivity index) is a simple relationship, approximately reflecting the capacity of a well, which is useful for determining whether a well is sufficiently open to be a successful producer and for comparison with other wells. It neglects however transient changes and turbulence pressure drop at high flow-rates. For liquid phase low-temperature wells a more accurate productivity relationship can usually be put forward relating mass flow-rate (***q***) and well pressure (***p***):

$$p = p_0 - b(t)q - Cq^2 \tag{1}$$

The pressure can either be measured as down-hole pressure, depth to water-level if pumping from the well is required or well-head pressure if flow from the well is artesian. The term p_0 represents the initial well pressure before production starts, $b(t)q$ transient changes in well pressure reflecting transient changes in reservoir pressure and Cq^2 turbulent and frictional pressure changes in the feed-zones next to the well, where flow-velocities are at a maximum, and in the well itself. The term $b(t)$ depends on the properties of the reservoir in question, such as permeability and storativity (items (b) and (c) above). The injectivity index is, therefore, in fact an approximation of this term. To be exact the term will also include interference (due to production and/or reinjection) from other nearby wells. Figure 3 shows examples of productivity curves (often also called deliverability or output curves) for three liquid-phase low-temperature geothermal wells with vastly variable production characteristics, based on real Icelandic low-temperature examples.

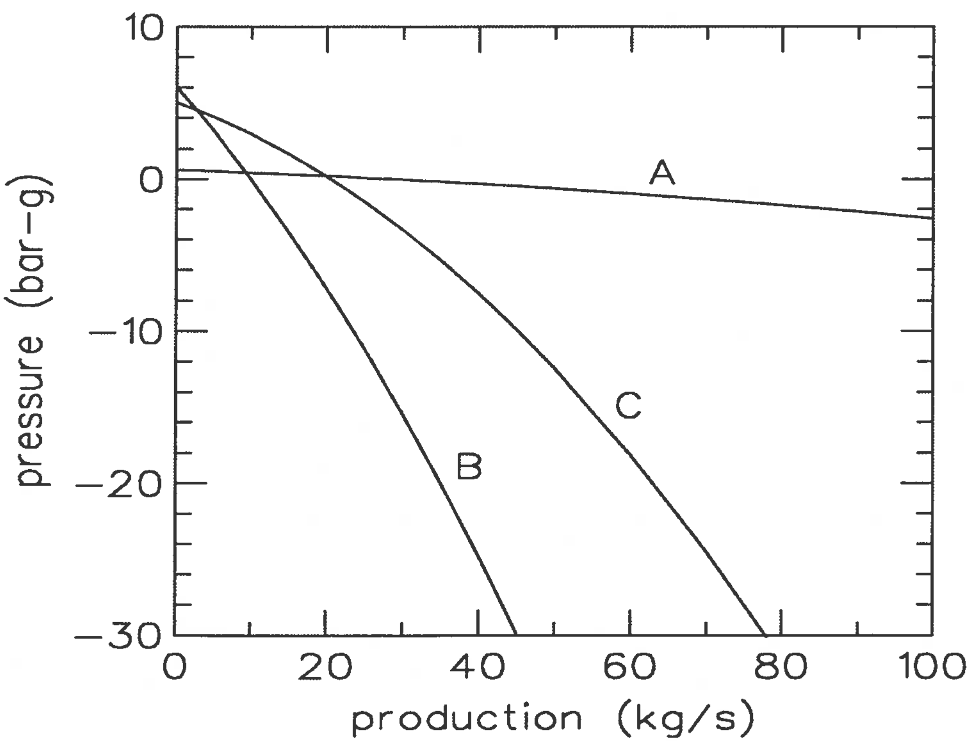

FIGURE 3: Examples of productivity curves (i.e. Equation 1) for liquid-phase low-temperature geothermal wells with varying characteristics. Based on real Icelandic examples (see Axelsson and Gunnlaugsson, 2000).

The permeability-thickness (item (b)) and storage coefficient (item (c)) are estimated through an analysis of pressure transients measured during completion well-tests (called pressure transient analysis), which is a more accurate analysis than involved in the simple estimation of an injectivity index. The corresponding analysis methods most often applied in the geothermal industry have been inherited from groundwater science (they have also been adopted by petroleum reservoir engineering). These classical methods will not be discussed in detail here but instead the reader is referred to the works by Bödvarsson and Witherspoon (1989) and Grant and Bixley (2011). The foundation of the methods is the well-known Theis model, a sketch of which is presented in Figure 4, along with sketches of a few variants of the basic model. The Theis model comprises a model of a very extensive horizontal, permeable layer of constant thickness, confined at the top and bottom, with two-dimensional, horizontal flow towards a producing well extending through the layer.

Well-test data are analysed on basis of the Theis model, and its variants, by fitting the pressure response of the model to observed pressure response data. Consequently the parameters of the model provide an estimate of the parameters of the reservoir being tested. Historically this fitting has been done by using semi-logarithmic plots or the type-curve method. The former method is still used as it is quite simple and effective, in spite of simplifying assumptions; Figure 5 shows the calculated responses of the Theis model and its variants in Figure 4, on a semi-logarithmic plot. The type-curve method has been replaced by more modern, computerized fitting, which today is often applied through an inverse approach, automatically yielding best fitting reservoir parameter estimates. Figure 6 shows one of the first examples of the results of computerized fitting of step-rate injection data, from a well drilled into the Krafla volcanic geothermal system in Iceland. It may be mentioned that today combined fitting of the pressure transients and their derivative (derivative analysis) is increasingly being used.

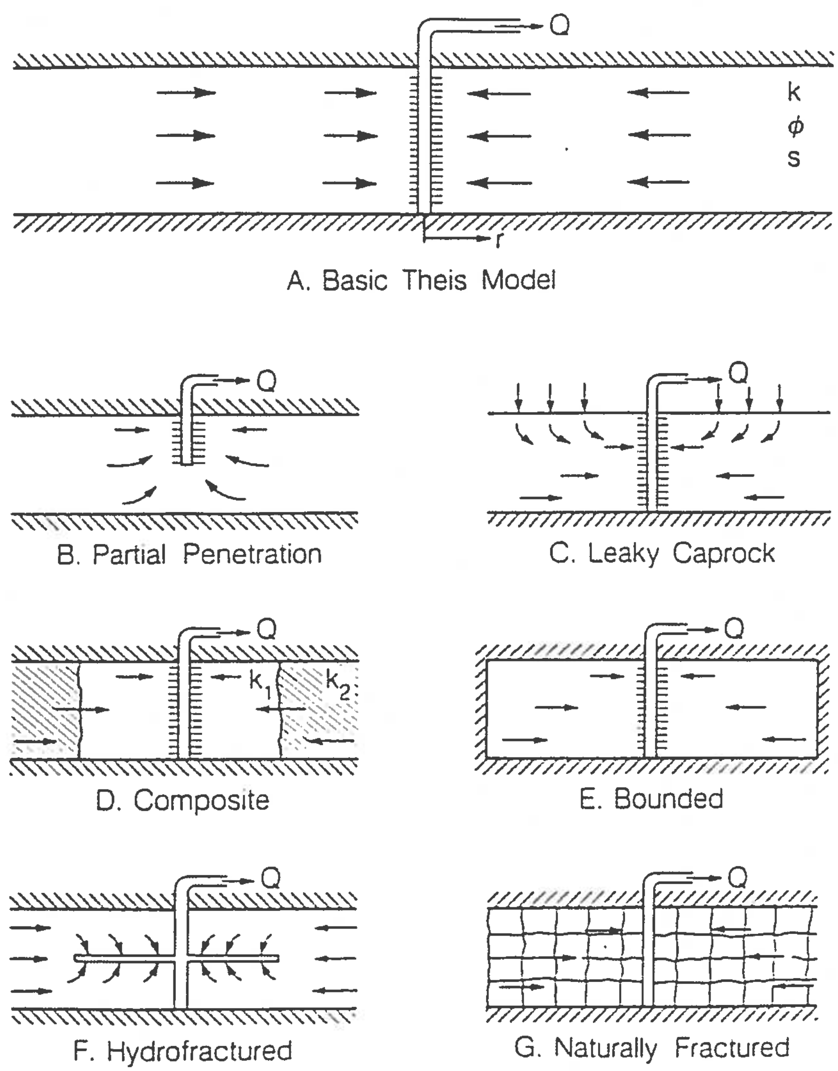

FIGURE 4: A sketch of the basic Theis-model (top) used to analyse pressure transient well-test data along with several variants of the basic model (Bödvarsson and Whiterspoon, 1989)

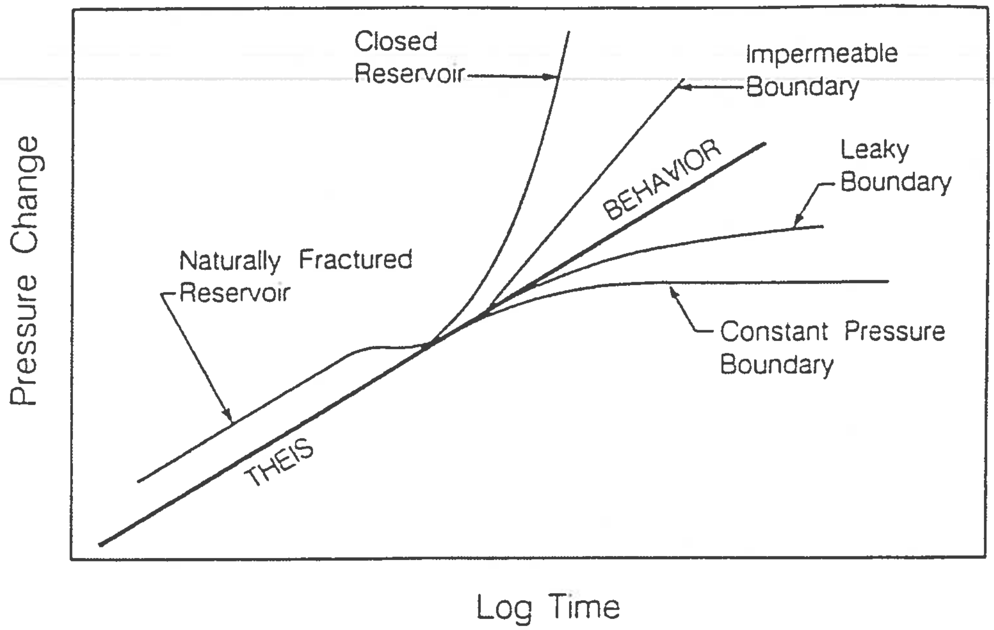

FIGURE 5: Responses of the models in Figure 4 plotted on a semi-logarithmic plot (linear pressure change vs. logarithmic time) demonstrating the linear behaviour, which is the basis of the semi-logarithmic analysis method (Bödvarsson and Whiterspoon, 1989)

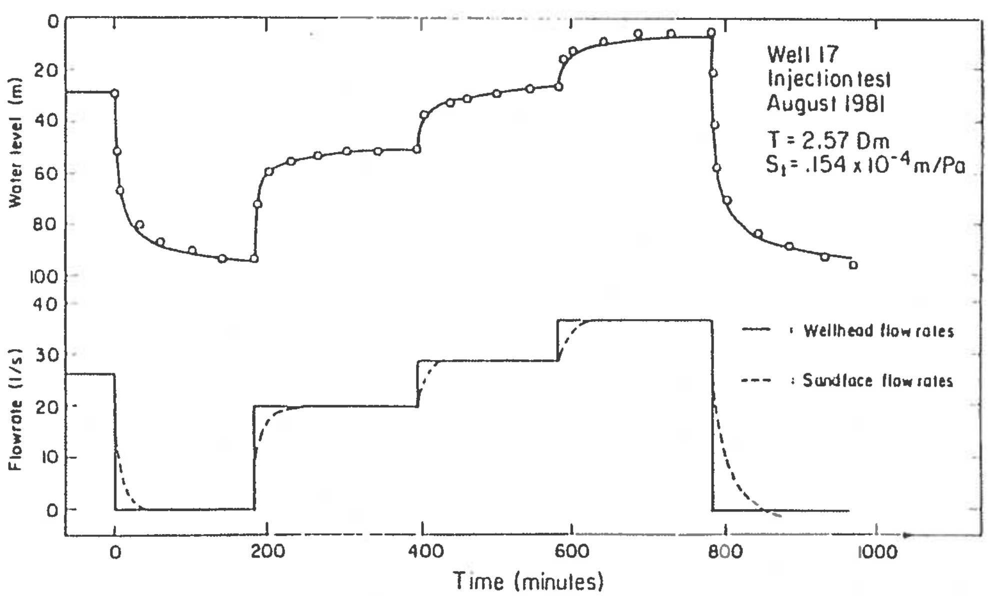

FIGURE 6: An early example of the results of computerized simulation of step-rate injection test data by a Theis-model response (Bödvarsson et al., 1984). Data from a high-temperature production well in the Krafla volcanic geothermal system in N-Iceland.

It may be mentioned that Rutagarama (2012) presents a good treatise on the role of well-testing in geothermal resource assessment while Sarmiento (2011) discusses completion testing in more detail than done here, based on examples from high-temperature geothermal fields in the Philippines. It should also be stressed that the analysis method for geothermal well-test data introduced briefly above is based on particular, simplifying assumptions, which are not always applicable. This applies e.g. to the assumption of two-dimensional flow, while three-dimensional flow may be important in many geothermal situations. Therefore, the results of geothermal well-test analyses should be viewed with the model applied in mind. In other words the results are actually model-dependent.

2.3 During stimulation

Stimulation operations are frequently part of the completion programs of geothermal wells, as already mentioned. This will only be touched upon briefly here but the reader is referred to the lecture by Thórhallsson (2012), and other related lectures, at this short course, as well as the paper by Axelsson and Thórhallsson (2009) on stimulation of geothermal wells drilled in the basaltic environment of Iceland. The purpose of stimulation operations is to enhance the output of wells either by improving near-well permeability that has been reduced by the drilling operation itself or to open up hydrological connections to permeable zones not intersected by the well. The methods most commonly used involve applying high-pressure water injection, sometimes through open-hole packers, or intermittent cold water injection with the purpose of thermal shocking. Chemical stimulation (mostly applying acid) methods are also used. Experimental procedures, such as using deflagration to stimulate wells and propellants to maintain stimulation achieved, have also been tested. Stimulation operations commonly last a few days while in some instances stimulation operations have been conducted for some months. The stimulation operations often result in well productivity being improved by a factor of 2–3.

Emphasis is placed on careful reservoir monitoring during stimulation operations. Seismic monitoring has e.g. provided valuable information in some few cases. Further research and "state of the art" technology are needed to better understand stimulation processes, however, and to improve the outcome of geothermal stimulation operations. The results of stimulation operations are usually assessed through repeated step-rate well-tests and by comparing injectivity (or productivity) indices estimated before, during and after stimulation operations. Changes in skin factor can also be used to evaluate the outcome of such operations.

3. RESERVOIR PHYSICS RESEARCH DURING WARM-UP AND TESTING

3.1 During warm-up

After the drilling of a geothermal well is completed a well is usually allowed to recover in temperature (heat up) from the cooling caused by drilling fluid circulation and cold water injection. How long depends on local conditions and the development project being followed, but this usually takes a few months. The principal reservoir engineering research conducted during this period is repeated temperature and pressure logging. The temperature data thus collected is used to estimate the undisturbed system temperature, often called formation temperature, as wells usually don't recover completely during the recovery period. Different methods can be used for this estimation, but the method most often applied is the so-called Horner method (Grant and Bixley, 2011). An example of the results of its application is presented in Figure 7. The pressure data collected are used to estimate the reservoir pressure with the intersection of several warm-up pressure profiles defining the so-called pivot point. If a single feed-zone dominates a well the pivot point defines the reservoir pressure at the feed-zone depth. If two, or more, feed-zones exist in a well the pivot point defines average conditions instead.

Figure 8 shows examples of two warm-up temperature logging series from the Olkaria Domes geothermal field in Kenya, along with the estimated formation temperature conditions for both wells. In these examples 5 – 6 warm-up temperature logs were measured for a period of up to two months. This is close to being ideal and in many other cases neither such a long warm-up period nor this number of logs is achieved.

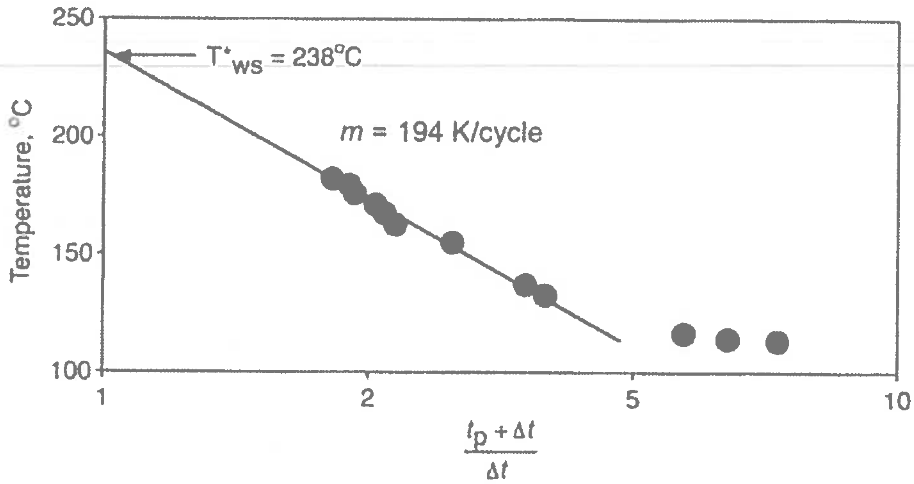

FIGURE 7: Example of the use of the Horner method to estimate undisturbed formation temperature from heating-up data (temperature recovery data) collected at a certain depth following drilling completion (Grant and Bixley, 2011)

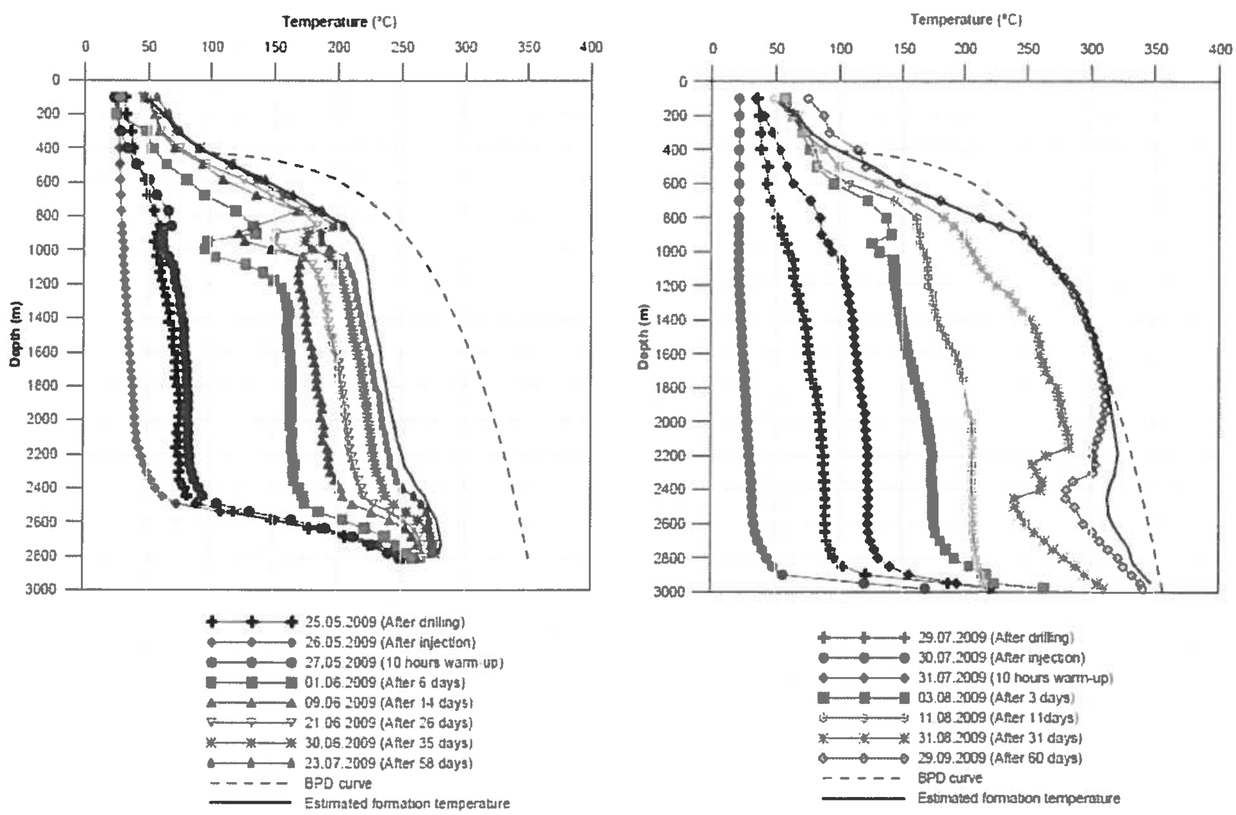

FIGURE 8: Two examples of repeated temperature logs measured in two wells in the Olkaria Domes geothermal field in Kenya, OW-911A and OW-912, with the purpose of estimating the undisturbed temperature (formation temperature) around the wells (Mwarania, 2010). Also shown are the estimated formation temperature profiles for each well along with boiling point curves for estimated formation pressure conditions.

3.2 During output testing

After a well has been allowed to warm up sufficiently it's ripe for output testing. In the case of high-temperature wells this usually involves spontaneous discharge through boiling at depth in the wellbore, which creates the pressure drop necessary to drive the flow of geothermal fluid from the reservoir, through the well, and to the surface (discharge testing). In the case of lower temperature wells either sufficient overpressure in the reservoir, which creates free-flow (artesian) from wells, or pumping, is required for output testing. In many cases high temperature wells need to be discharge stimulated through a variety of methods before discharge can be sustained. Such methods are e.g. discussed by Sarmiento (2011).

Measuring the well discharge of single-phase (liquid water or dry steam) wells is relatively straight-forward whereas measuring the discharge (both mass- and energy-flow) of a two-phase well is much more complex. This involves measuring, or estimating, two out of four key parameters; liquid-flow (q_w), steam-flow (q_s), total flow (q_{total}) or enthalpy of the flow (h_t). Once any two have been determined the other parameters can be estimated based on the following equations:

$$X = q_s / q_{total} \tag{2}$$

$$q_{total} = q_w + q_s \tag{3}$$

$$h_t = X h_s + (1 - X) h_w \tag{4}$$

Here X is the mass-fraction of steam and h_s and h_w enthalpy of water and steam, respectively, at separation conditions on surface.

The following are the main methods used to estimate the output of two-phase wells at surface (see also Grant and Bixley, 2011):

(1) Liquid and steam phases are separated (in a separator) and each phase measured separately. Probably the most accurate method but requires the most complex instrumentation.
(2) This method applies to wells with liquid inflow and known feed-zone temperature. Liquid flow measured after separation and enthalpy of flow estimated on basis of feed-zone temperature.
(3) This method also applies to wells with liquid inflow and known feed-zone temperature. Total flow estimated by Russel James method and enthalpy of flow on basis feed-zone temperature. The Russel James method is an empirical method, relating total flow and flowing enthalpy, based on measuring the critical lip-pressure at lip of a pipe discharging the two-phase mixture (James, 1970; Grant et al., 1982).
(4) A combination of using the Russel James method on the total flow and consequently measuring the liquid flow-rate after separation.
(5) Using two different chemical tracers to measure the flow-rate of each of the phases in a pipeline (Hirtz et al., 2001). This method is increasingly being used with success, doesn't require disruption of power production.

Figure 9 shows an example of discharge test data, again from the Olkaria Domes field in Kenya. It shows a typical behaviour resulting from the well heating up, actually continuing from the warm-up period after drilling, i.e. enthalpy increases and water flow decreases as the test progresses. In this case the test lasted about a month, but ideally discharge tests should last until an approximate equilibrium is reached, which often may take several months. In some cases equilibrium is not attained. The behaviour of discharging wells is, however, quite variable, depending on the nature of the geothermal reservoir involved and well properties, as e.g. discussed by Bödvarsson and Witherspoon (1989) and Grant and Bixley (2011).

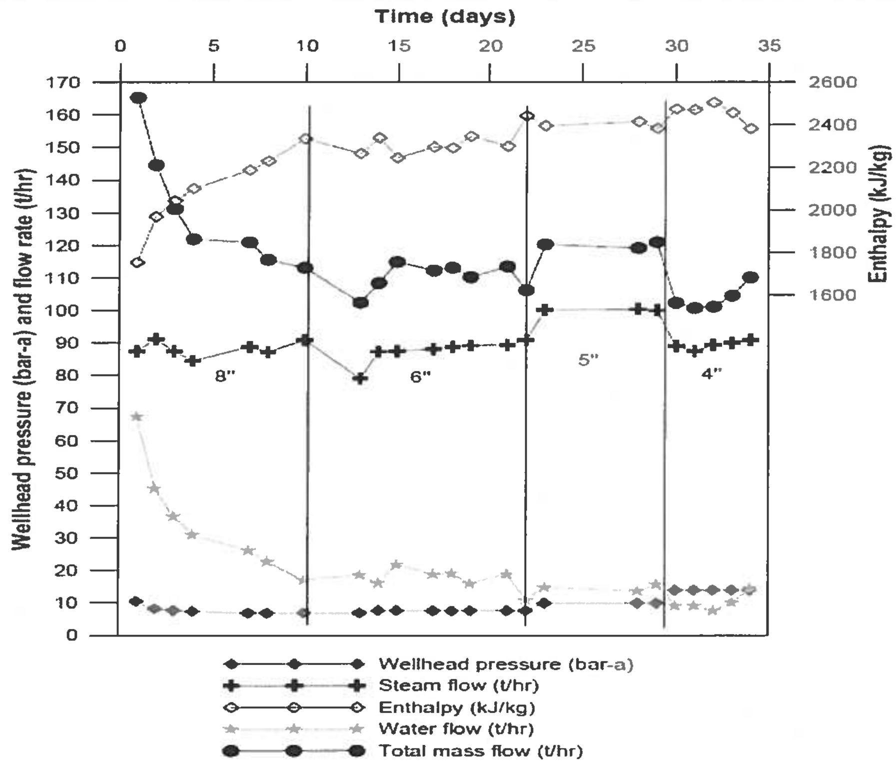

FIGURE 9: Discharge test data from well OW-915A in the Olkaria Domes field in Kenya (Mwarania, 2010).

The productivity of geothermal wells is often presented through a simple relationship between mass flow-rate or production (measured as mentioned above) and the corresponding pressure change, either in down-hole or well-head pressure, as a first-order approximation, as already discussed (see discussion on injectivity/productivity above). This relationship is often termed production characteristics or well deliverability (output curve). In general the productivity of geothermal wells is a complex function of well-bore parameters (diameter, friction factors, feed-zone depth, skin factor, etc.), feed-zone temperature and enthalpy, feed-zone pressure, reservoir permeability and storativity, well-head pressure or depth to water level during production and temperature conditions around the well. For two-phase high-temperature wells a simple relationship as given by Equation 1 can't be set up between flow-rate and well-head pressure.

Figure 10 shows examples of productivity curves for two types of two-phase high-temperature geothermal wells with vastly variable production characteristics. It exemplifies a clear distinction between wells with single phase feed-zone inflow, which show typical bell-shaped curves like liquid-phase wells (Figure 3), and wells with two-phase inflow, which show little variation in output with changes in well-head pressure. The possible reasons for the characteristics of the latter wells have been discussed by Stefánsson and Steingrímsson (1980) as well as Bödvarsson and Witherspoon (1989).

When analysing data from flowing two-phase wells researchers need to resort to so-called wellbore simulators, i.e. computer software which numerically solves the relevant physical equations to simulate flow-, pressure- and energy conditions in the wells in question. These include mass conservation, pressure changes due to acceleration, friction and gravitation as well as energy conservation. The *HOLA* wellbore simulator is a good example of such software (Björnsson and Bödvarsson, 1987).

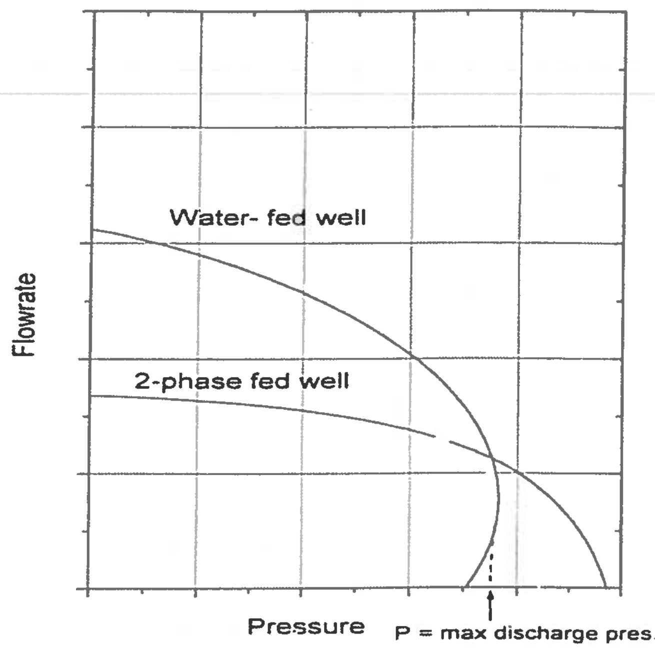

FIGURE 10: General examples of productivity curves for two types of two-phase high-temperature geothermal wells

An extremely important part of discharge testing is monitoring of down-hole pressure during testing, either continuously or intermittently. This is not done in nearly all cases, however, as it may be technically difficult and/or quite expensive. If such data are available it is common to define a productivity index (***PI***) simply as the ratio between a change in mass flow-rate and a corresponding change in well pressure, preferably measured at the main feed-zone of a well, as first-stage analysis. For low-temperature, single-phase wells the productivity index is normally quite comparable to the wells injectivity index, if that has been estimated. This is, however, not the case for high-temperature, two-phase wells because of drastically contrasting conditions during injection of colder fluids and high-temperature production. This can be seen clearly in Figure 11 which shows a comparison of productivity and injectivity indices for a number of high-temperature wells worldwide. The figure shows a considerable scatter, at least not a clear one-to-one relationship. A conservative relationship assuming that ***PI*** = ***II***/3, which has been suggested, is supported by the figure. This is logical in the case of two-phase wells where boiling causes a much greater pressure draw-down than during injection. Yet it seems evident that in the case of highly productive wells the productivity index is considerably larger than the injectivity index (Axelsson and Thórhallsson, 2009).

Conventional pressure transient analysis of down-hole pressure data measured during discharge testing is of course a more accurate method of analysis than the estimation of a productivity index (second stage analysis). The same methods may be used for this purpose as described above for the analysis of step-rate well-test data. This analysis yields again estimates of permeability-thickness and storage coefficient, estimates which should be representative for larger reservoir volumes than estimates based on step-rate well-test data, because of the much longer time scale involved. In addition it involves reservoir temperature conditions instead of lower temperature conditions, with an associated viscosity ambiguity, during step-rate testing.

In addition to simple monitoring of down-hole pressure during discharge testing supplementary pressure transient testing is sometimes performed. This involves in particular pressure recovery monitoring after discharging wells are shut in and pressure interference monitoring in near-by monitoring wells. Such data add greatly to the reservoir physics analysis of discharge tests. It should be noted, however, that in the case of high-temperature, especially two-phase, reservoirs pressure propagation is very slow so pressure interference may be limited. In lower temperature, liquid-dominated, reservoirs interference testing is extremely valuable. Finally it should be noted that in addition to the conventional reservoir analysis performed on the well data discussed above, the data are extremely valuable for the calibration of different kinds of dynamic reservoir models (see also chapter on monitoring), i.e. numerical reservoir models.

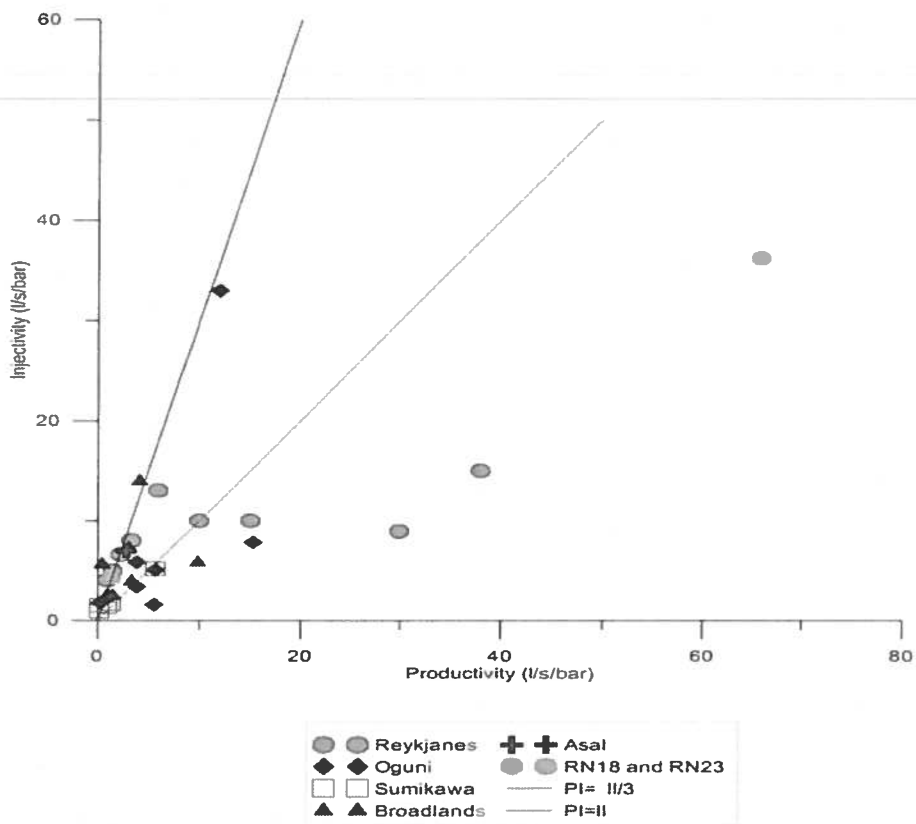

FIGURE 11: The relationship between productivity and injectivity indices for several high-temperature geothermal wells worldwide (Rutagarama, 2012). The red line represents ***PI = II*** while the blue line represents ***PI = II***/3.

3.3 For Reinjection wells

In the case of reinjection wells, either drilled specifically as such or other types of wells converted into reinjection wells, much of the same reservoir physics research is conducted as described above. The main difference is that reinjection wells don't need to be discharge tested so a step-rate injection test suffices. After well completion injection testing needs to be continued for a long period, usually several months. During this long-term injection testing tracer test are often conducted to study the connection between the designated reinjection well and near-by production wells, with the danger of cooling of the production wells in mind. A more detailed discussion of reinjection well research is beyond the present paper and for more information the reader is referred to another paper presented at this short course (Axelsson, 2012). It may be specifically mentioned, however, that the injectivity of reinjection wells sometimes continues to increase during long-term injection, most likely due to thermal stimulation.

4. MONITORING

Management of geothermal resources relies on adequate knowledge on a geothermal system and the most important data on a geothermal system's nature and properties are obtained through monitoring of its response to long-term utilization (Axelsson, 2008). Careful monitoring of a geothermal reservoir during exploitation is, therefore, an indispensable part of any successful management program. If the understanding of a geothermal system is adequate, monitoring will enable changes in the reservoir to be seen in advance. Timely warning is thus obtained of undesirable changes such as decreasing generating capacity due to declining reservoir pressure or steam-flow, insufficient injection capacity or possible operational problems such as scaling in wells and surface equipment or corrosion. The importance of a proper monitoring program for any geothermal reservoir being utilised can thus never be over-emphasised. In addition utilization and monitoring can be viewed as really long-term reservoir testing, i.e. a continuation of the production testing discussed above.

Monitoring the physical changes in a geothermal reservoir during exploitation is in principle simple and involves measuring the (1) mass and heat transport, (2) pressure, and (3) energy content (temperature in most situations). This is complicated in practise, however (Axelsson and Gunnlaugsson, 2000). Measurements must be made at high-temperatures and pressures and reservoir access for measurements is generally limited to a few wells, and the relevant parameters can't be measured directly throughout the remaining reservoir volume.

The parameters that need to be monitored to quantify a reservoirs response to production may, of course, differ somewhat, as well as methods and monitoring frequency, from one geothermal system to another (Axelsson and Gunnlaugsson, 2000). Monitoring may also be either direct or indirect, depending on the observation technique adopted. Below is a list of directly observable basic aspects that should be included in conventional geothermal monitoring programs, most of which can be viewed as reservoir physics parameters:

(1) Mass discharge histories of production wells (pumping for low-temperature wells).
(2) Temperature or enthalpy (if two-phase) of fluid produced.
(3) Water level or wellhead pressure (reflecting reservoir pressure) of production wells.
(4) Chemical content of water (and steam) produced.
(5) Injection rate histories of injection wells.
(6) Temperature of injected water.
(7) Wellhead pressure (water level) for injection wells.
(8) Reservoir pressure (water level) in observation wells.
(9) Reservoir temperature through temperature logs in observation wells.
(10) Well status through diameter monitoring (caliper logs), injectivity tests and other methods.

Monitoring programs have to be specifically designed for each geothermal reservoir, because of their individual characteristics and the distinct differences inherent in the metering methodology adopted. Monitoring programs may also have to be revised as time progresses, and more experience is gained, e.g. monitoring frequency of different parameters. The practical limits to manual monitoring frequency are increasingly being offset by computerised monitoring, which actually presents no upper limit to monitoring frequency, except for that set by the available memory-space in the computer system used. Data transmission through phone networks is also increasingly being used. Figures 12–14 show examples of different kinds of direct monitoring data.

Indirect monitoring involves monitoring the changes occurring at depth in geothermal systems through various surface observations, i.e. geophysical surveying. This will not be discussed in any detail here, but more information can be found in Axelsson (2008) and Axelsson and Gunnlaugsson (2000). The indirect monitoring method having the greatest applicability at present seems to be combined surface elevation and gravity monitoring. Through repetitions of such surveying the mass balance of geothermal systems being utilized can be evaluated, i.e. the relevance of natural recharge and effect of reinjection. Micro-seismic monitoring can also be of great value in advancing the understanding of geothermal systems.

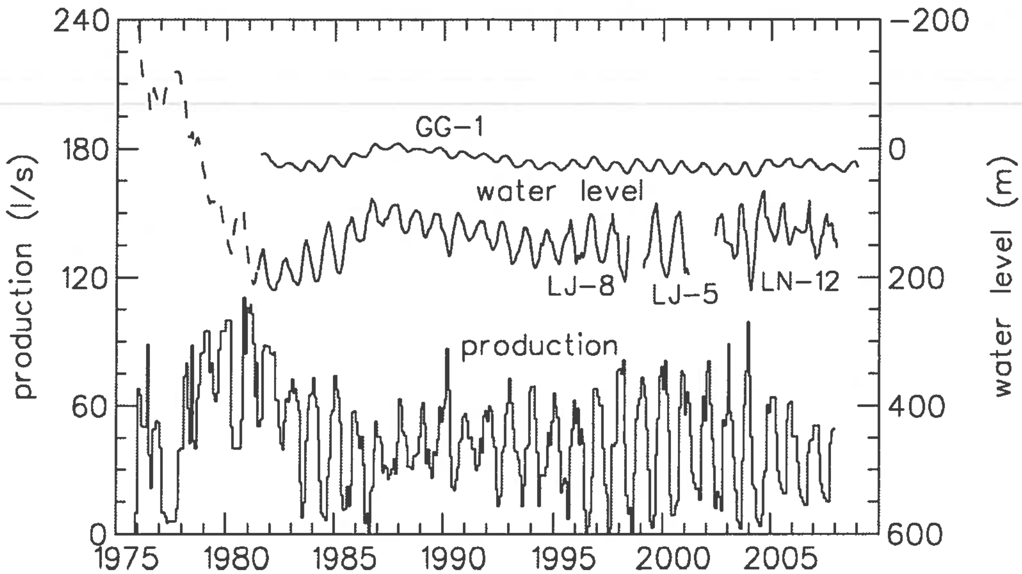

FIGURE 12: Production and water-level history of the Laugaland low-temperature geothermal system south of Akureyri in N-Iceland from 1976 to 2007 (Axelsson et al., 2011), presented as an example of long-term monitoring data from a low-temperature field. The broken line indicates estimated water-level. Wells LJ-5, LJ-8 and LN-12 are inside the field while well GG-1 is 2 km from the fields centre.

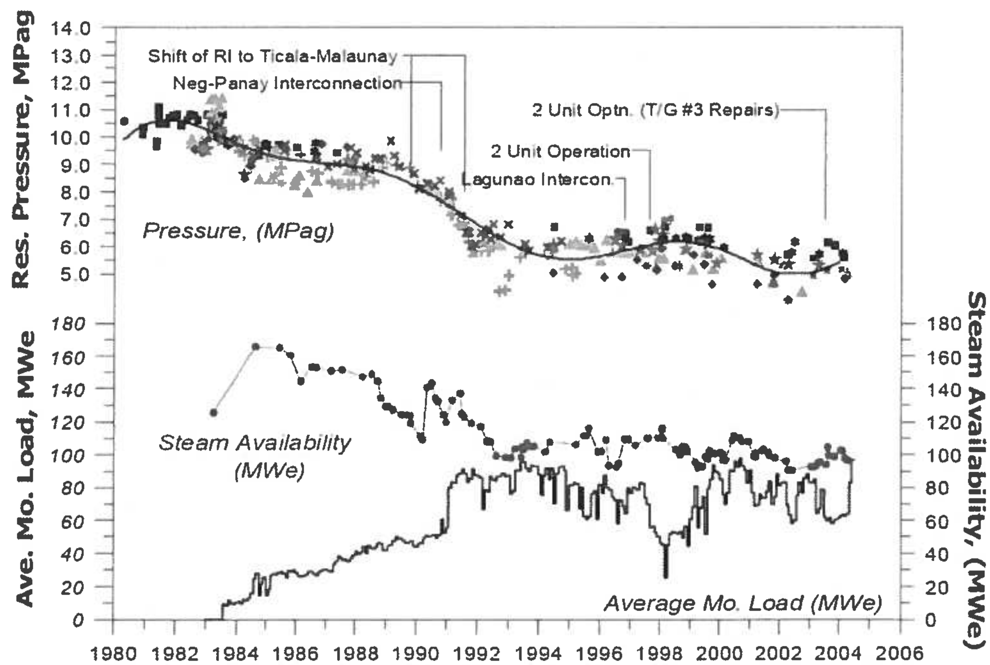

FIGURE 13: The production and pressure response history of the Palinpinion-1 geothermal field in the Philippines (Aqui et al.,2005), presented as an example of long-term monitoring data from a high-temperature field

It should be mentioned that such monitoring data are essential for calibration of models of geothermal systems used to assess their production capacity and for long-term management purposes. A discussion of this is beyond the purpose of this paper, but the reader is referred to the writings of Grant and Bixley (2011), Pruess (2002) and Axelsson et al. (2005).

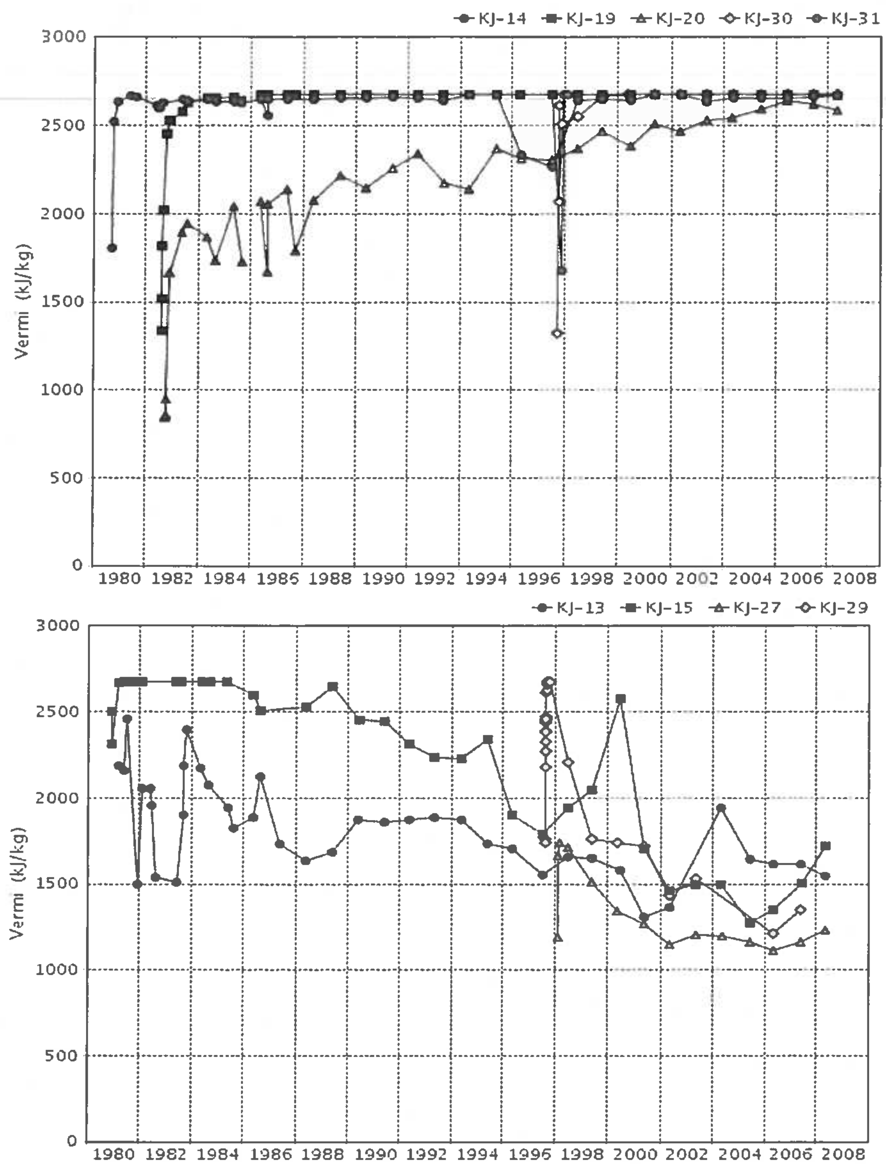

FIGURE 14: Enthalpy monitoring data from two sub-fields of the Krafla geothermal field in N-Iceland of quite contrasting behaviour (Mortensen et al., 2009). The top part of the figure shows indications of increased boiling due to limited recharge while the bottom part shows the opposite behaviour.

5. CONCLUSIONS AND RECOMMENDATIONS

This paper reviews the main reservoir physics (reservoir engineering) research conducted through geothermal wells, in particular logging, well-testing and monitoring. It emphasises temperature and pressure logging during drilling, completion, warm-up and discharge testing as essential in estimating accurately reservoir physical conditions as well as for appraising well feed-zones. Down-hole pressure transient monitoring during step-rate well-testing, discharge testing and pressure recovery is, furthermore, indispensable for the evaluation of critical reservoir properties such as permeability and storativity, through pressure transient analysis. In addition the paper emphasises the crucial role of physical monitoring of the energy output (mass discharge and enthalpy) and the reservoir response (pressure and temperature changes) during long-term (years – decades) utilization. These reservoir physics and monitoring data are essential for calibration of models of geothermal systems used to assess their production capacity and for long-term management purposes.

Injectivity indices of geothermal wells estimated on the basis of step-rate well-test data and productivity indices estimated from down-hole pressure data collected during discharge testing provide important first stage estimates of well productivity. It should be kept in mind that these parameters, which are assumed constant, are only approximate as well productivity is usually a slowly varying function of time. In addition injectivity indices, which are usually the first estimates of the capacity of wells, available at the end of drilling, are not accurate estimates of the productivity indices for the corresponding wells. Comparison of the two parameters for numerous geothermal wells worldwide indicates that the productivity index of a well may be expected to be lower than its injectivity index, even as low as one-third. Yet there are cases where the productivity index is considerably greater than the injectivity index, especially for highly productive wells. The exception is liquid-phase, low-temperature wells where a one-to-one relationship usually exists between injectivity and productivity.

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Servicing Geothermal Wells during Completion and Follow-up Monitoring

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Keywords: Iceland GeoSurvey, geothermal, drilling, geophysical, logging, high temperature, production, injection, completion, follow-up, monitoring.

ABSTRACT

Servicing geothermal production, injection and exploration wells at Iceland GeoSurvey begins with well siting and design. Siting and design are based on geophysical and geological investigations and measurements. To successfully drill and complete a geothermal well several factors have to be taken into account. Initially the contractor and the client (C&C) have to agree on what the criteria of success are and how to achieve them. After deciding on well design C&C have to select a fitting completion program for logging purposes. The geophysical logging implemented is chosen from a more or less standardized set of measuring programs with only slight variations as to what part of the well is to be logged during drilling. More than 20 specialists in the technical department and roughly 15 geologist, 6 logging trucks and some 60 tools are subject to careful planning as Iceland GeoSurvey undertakes 24-hour manning on drill-site, according to long-term schedules.

Monitoring measurements are not subject to the same strict manning schedule but in order to meet client requests swift and efficiently, slick-line trucks and manpower are also included in the aforementioned long-term schedules.

1. INTRODUCTION

Both geothermal drilling and geothermal logging have developed from the petroleum industry, Stefánsson and Steingrímsson (1980). However, there are major differences between these two types of logging concerning objectives, operation and interpretation. The main objective in geothermal logging is to locate fractures whereas in petroleum logging determination of porosity and hydrocarbon saturation are the main objectives. Therefore the petroleum logging know-how cannot be applied directly to the geothermal logging. Assessment of reservoir lithology and permeability is a common denominator for both types of logging, but basic differences exist since the geological settings for the majority of petroleum reservoirs are sedimentary rocks, whereas this is true for very few high temperature (HT) geothermal reservoirs.

Standard well logging instrumentation in the petroleum industry is capable of working at temperatures up to 150-180°C, which is too low for most geothermal logging. In Iceland temperatures up to 386°C have been recorded. Up until present this problem has been addressed by cooling the well bore but the process is costly and induces undesirable thermal stress on casings. In later years an increasing number of tools and cables have been developed for high temperature logging. One future development might be that the standard logging program is moved into HT logging only after the drill rig has left the well. Another scenario is that the logging tools are moved into the drill string as it has been done in the oil and gas industry. In the last few years focus on cooling the production part of the geothermal wells has been increasing since alternating cooling and heating opens fractures thus improving well output but ongoing research seems to indicate fracture close-up with rising temperatures after cooling, Kristjánsson and Gunnarsson (2009).

Interpretation methods are relatively sophisticated in the petroleum industry. Developing and refining interpretation of logs from geothermal fields is still work in progress and in the latest years more interpretation programs have been developed but clearly the need for standardization is as great as ever and much can still be learned from the petroleum industry, Rider (1991).

The technical staff at Iceland GeoSurvey is very apt in dealing with special tasks and unforeseen problems during the drilling phase. With the introduction of directional (deviated) drilling an increase has been seen in cases of stuck drill string. The almost exponential increase in drilled wells per year, seen in the last decade (**Figure** 1), has meant a similar increase in logging, personnel, equipment and also a slight increase in tools lost in-hole (LIH) which can be accounted for mostly as a result of the increased activity.

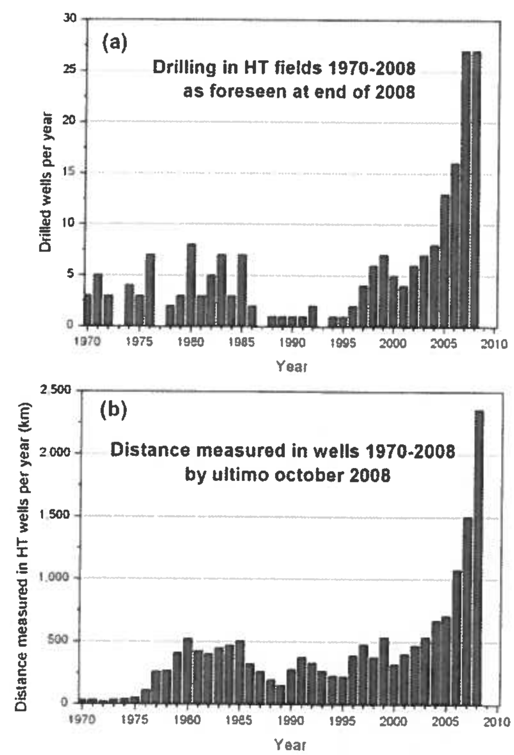

Figure 1: a) Number of drilled wells per year, from 1970 to 2008. b) Distance measured in wells under both low- and high-temperature conditions, for the same period. All data is from the Iceland GeoSurvey database.

2. PLANNING AND DESIGN

After initial geophysical and geological surface investigations and measurements are completed well siting can be localized and in the process the well design will be finalized suiting/complying with the chosen target.

2.1 Planning and Contracting

Once results from surface investigations are available and the site and target has been established the next step is to design the well to comply with the contractor's wishes and agree on a logging and completion program for the well. It is not the aim of this paper to cover the many details in planning contracts between C&C's. Thus the following table (**Table** 1) gives a very simplified overview. The actual programs are much more detailed and also include specific information on well diameter, casing sizes and material to be used, e.g. steel, cement or mud.

2.2 Well Design

Designing HT geothermal wells has been standardized to a large extent during the last decades and two main designs are implemented in Iceland. The so-called "wide" program is completed in a 12-1/4" diameter section with a 9-5/8" liner. The wide program is mainly used for production wells in the fields owned by Reykjavik Energy (RE) and HS Orka (formerly Hitaveita Suðurnesja). These fields are situated in the South-Western corner of Iceland (**Figure** 2) where Nesjavellir and Svartsengi, respectively, are the fields with the longest production history. The so-called "slim" program is completed in a 10-3/4" diameter section with a 7-3/8" liner. The slim program is used by RE for exploration wells and as production wells by the Landsvirkjun company (LV). Situated in the North (**Figure** 2) Krafla is the field with the longest production history, exploited by LV.

Table 1: Simplified completion and logging program.

Stage	Drilling company	Iceland GeoSurvey – logging	Reports
1. Safety casing	Drilling and casing installation	Temperature, caliper, CBL, *neutron-neutron, natural gamma, resistivity	Daily progress, casing and cementing
2. Production casing	Drilling, casing installation and main valve	Temperature, caliper, neutron-neutron, natural gamma, resistivity, CBL, #gyro	Daily progress, casing, cementing and #kick-off
3. Production part	Drilling and liner installation	Temperature, caliper, neutron-neutron, natural gamma, resistivity, #gyro, pressure	Daily progress, #well path and liner

*As a rule the lithological program is left out in the first stage, when overall knowledge of the field is abundant. Applies only when the well is deviated.

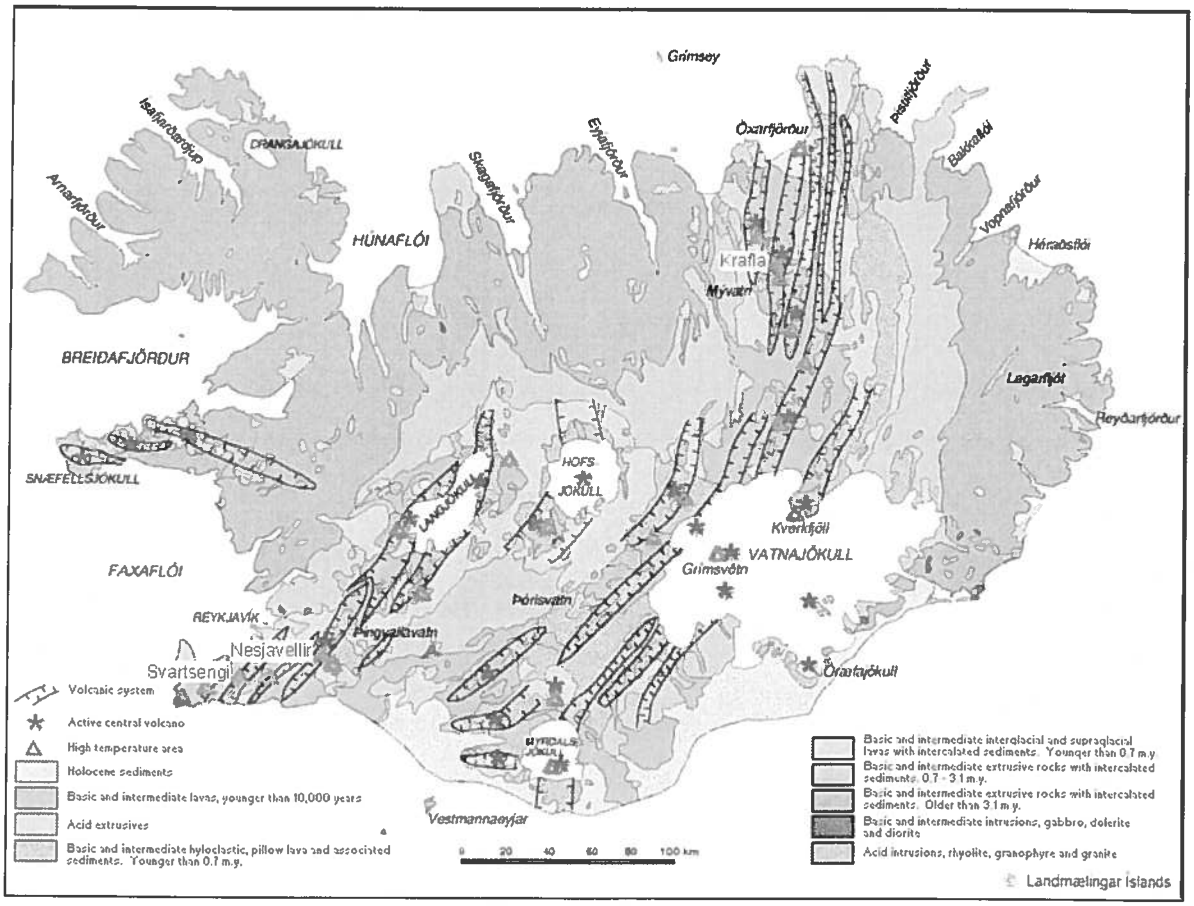

Figure 2: Map of Iceland showing Nesjavellir, Svartsengi and Krafla geothermal fields, located in the active volcanic zones.

3. LOGGING SERVICES WHILE DRILLING

The logging teams from Iceland GeoSurvey are on standby at all hours and man the logging trucks on a weekly basis, divided into 12 hour day and night shifts. This means that logging can continue non-stop and ensure that the contractor gets results and consultancy on a steady basis from trained experts. Last but not least it succeeds in saving the contractor costly rig time since the logging service package as a whole costs only a mere fraction of what it costs to pay the rig rate during idle time, Danielsen (2008).

During logging, quality and efficiency is of great importance. The head of the technical department together with the assistant head sees to the overall logistics in order to manage and supervise technicians, tools and trucks. On drill site it is the loggers on call that ensure that all regulations, safety rules and quality standards are followed. One illustrative example is that zero depth on a drill site is referenced to the rig floor. Since the drillers use rig floor as zero depth concerning geology (i.e. drill cuttings) and the real time drilling information (i.e. depth, torque, pump rate, circulations losses, hours of drilling etc.) everyone refers to the rig floor as zero depth and to minimize the possibility of misunderstandings. Loggers also uses rig floor as zero reference while logging during drilling. This procedure has been standardized and simplified with the introduction of the Warrior logging system from Scientific Data Systems (SDS), some two and a half years ago, since the system has built-in zero for each application. In the final well reports and subsequent HT monitoring logging, zero is moved down to ground level and all prior measurements and data thus corrected according to ground zero.

During the exploratory drilling phase determining borehole geology supported by geophysical well logging are the main tasks, which together with results from well testing make the basis for a revised geological and hydrological model of the reservoir, Mortensen and Flovenz (2008), and preliminary interpretation of logs and measurements on-site is needed. A brief reading of the different logs allows results to be interpreted on-site through collaboration between technicians, geologist and geophysicist. An explanation can be found in the following sub-sections, with the main emphasis on what Iceland GeoSurvey strives to comply with as a quality minded logging service company.

3.1 Temperature Logging

The temperature log (**Table** 1) is the most common log to run in any given well because it suits diverse purposes. The temperature log is mainly used to locate aquifers. Information on aquifers is very useful not only when locating the main in-flow for production purposes but also when the drilling company is cementing for casing purposes especially for very deep production casings where loss of circulation and powerful aquifers have to be known in order to ensure successful cementing for the whole length of the casing. The temperature log is also very important for the drillers as it makes it possible to monitor the maximum temperature at the bottom hole assembly (BHA). Gor instance while running a gyro in the drill string it is necessary to make sure neither bit, motor, MWD (measurement while drilling) nor any other part of the BHA exceeds temperature of maximum tolerance. Since most tools used in lithological logging today have considerably lower temperature tolerance than the temperature tools, the temperature log also gives the logging team important information as to what depth it is safe to run the various lithological tools which as a rule follow completion of each drilling stage. The temperature log is run with a casing collar locator (CCL) sensor, and though the CCL log is used primarily for a practical application (counting connections in casing or drill string), it can also be a valuable addition to the lithological interpretation since it facilitates a relative estimate of the magnetic properties of the side rock.

3.2 Caliper Logging

Subsequent to the temperature log a caliper log is usually run (**Table** 1). On the basis of the measured width of the borehole from the caliper (diameter and cavities), drillers prepare for the cementing job (in the case of the two first stages only). As a rule of thumb twice the amount of cement will be available on-site, based on calculations from the caliper log. The drillers will have ample time to make all preparations while the remaining logs, such as the lithological logs, are run in the well. Besides using the caliper log for cement calculation purposes it is often applied when larger cavities or key-holes are troubling drilling progress in order to assist the drillers. Furthermore the log itself can be a useful addition to the lithological logs when interpretation of the geology for the final well report is being compiled.

3.3 Lithological Logging

All neutron-neutron (NN) and natural gamma tools (NG) run in Iceland (**Table** 1) are combined tools, acquiring two or three (dual neutron) log outputs. The neutron sensors measure the water content of the rock because H^+ atoms deflect neutron particles emitted from the radioactive source on the tool. Thus the porosity can be indirectly determined because high water content is indicated by high count rates and consequently relatively low porosity. The NN log furthermore gives an indication of the alteration stage of the minerals in the side rock. As a rule low NN API values indicates high alteration of basaltic rocks. The NG count originating from the side rock essentially reflects emission from the radioactive isotopes Potassium (K+), Thorium (Th) and Uranium (U). Emissions (K+) originates mainly from feldspar minerals in rhyolitic rock in Iceland but since Iceland is comprised overwhelmingly of volcanic rocks of basaltic composition, high NG counts are most likely indicators of rocks of rhyolitic composition, thus these are often used as stratigraphic markers in correlation between wells, Mostagel (1999). Thorium is common to most rocks and soils (average 12 ppm).

Since normal resistivity (NR) logging tools easily endure much higher temperatures than most neutron-neutron and natural gamma tools, they are usually run as the final log in the lithological logging program. The basic setup of a NR tool is three sensors; 16", 64" and SP (Self Potential) sensors where high resistivity generally indicates low porosity. The difference between the conductivity of the 16" and 64" sensors can be used quantitatively to estimate whether the formation is permeable or not, Johannesen (1972). It is essential for interpretation whether water based mud is used, as is the case only when drilling the first two stages of a geothermal well in Iceland, or only water, which is used in the production part, to avoid sealing of potential feed zones and lowering well output. The resistivity log also gives an indication of the alteration stage of the minerals in the side rock. As a general rule low resistivity will indicate low temperature minerals, such as smectite, zeolites and clays, whereas high resistivity will indicate high temperature alteration minerals, such as chlorite and epidote, Franzson et al. (2001).

As a later addition to lithological logging, the conductivity tool has been added. In a few fields in Iceland very low resistivity values are found which are close to or below the detection limit of the NR tool. The conductivity tool on the other hand has no problems with very low resistivity and has therefore been used with great success in these areas. The NR tool is still superior when it comes to HT tolerance.

3.4 Cement Bond Logging

With the completion of the lithological logging program the drillers will prepare installation and cementing of the casing as described in the above. In the case of the two first stages a Cement Bond Log (CBL) will then be run in the well to estimate the bond to the casing and the hardening of the cement (**Table** 1). When the cementing job is successful, a CBL is run to verify whether bonding of cement on the casing has begun and more importantly whether cement is present between casings, Rouillac (1994). If doubts arise as to the quality of the cement job more logs will be run and then it is also possible to estimate qualitatively how much hardening is progressing. The bonding to casing will deteriorate as soon as work on setting up the Christmas tree along with further drilling is done. Experiments done by Icelandic GeoSurvey has shown that it is still possible to get a relatively good estimate of the hardening after drilling and completion of the production part with the CBL as long as at least two CBLs has been done.

3.5 Directional Surveying

Directional drilling, hence directional surveying, has been an increasing element in geothermal exploration in Iceland during the last decade. Since Icelandic GeoSurvey undertook directional logging services three years ago, more than 80 wells has been logged successfully (**Table** 1). Two types of tools are in operation at present, one being a multi-shot true-north seeking tool from Stockholm Precision Tools (SPT), which is possible to run either as a wire-line SRO (surface read-out) application or in memory mode on a slick-line. The SPT tool is mainly used as a multi-shot tool, by Iceland GeoSurvey, for kick-off at the beginning of stage two and steering while completing build-up in the second stage, since it is easily and quickly deployed down-hole with very little preparation time. The German company System Entwicklungs GmbH (SEG) has developed the Target Inertial Navigation System tool (Target INS), which is also a true-north seeking tool. In early 2008 Flexit took over SEG and the tools are now marketed as Flexit Target INS. The SEG tool measures continuously while running in and out of the well and thus gives an on screen three dimensional survey. The SEG tool is mainly used in Iceland to survey the final well path. It takes longer time to deploy the SEG tool compared to the SPT tool, due to a lengthy calibration process but on the other hand the SEG tool has superior resolution and accuracy to the SPT tool. Since the SEG measures continuously while logging, it is actually faster to log deep wells (i.e. at depths below at least 1000 meters) than the SPT tool, since each measured point at depth needs a 1-3 minutes stop.

3.6 Pressure Logging

As seen in (**Table** 1) pressure is usually only logged after the well has been drilled to planned final depth. Transient injection step tests are then performed to estimate the injectivity index of the well. The injectivity index gives a rough idea of the corresponding productivity in megawatts (MW). Thus the result from the step-tests are used not only to decide whether to drill deeper in order to reach a more permeable formation, but also give the contractor a rough idea of the MW output for use in further planning, Steingrimsson and Gudmundsson (2006).

3.7 Additional Logging

Besides the more or less standardized programs described in the above and shown in **Table** 1, Iceland GeoSurvey has also undertaken televiewer (TW), sonic and video logging in the resent years.

TW logs have proved to be very useful in locating fractures and shifts in lithology. Compared to other tools run in the lithological program, TW logs are time consuming and expensive. In Iceland however much if not all fluid flow in geothermal wells can be directly related to fractures and thus making the TW log a most useful addition to the ordinary lithological logs. The Sonic log can be used in estimating cement bond and hardening, much in the same way as the regular CBL tools but the main reason for adding the tool to the ordinary lithological program is to measure the bulk density of the side rock. Since the bulk density is a function of the porosity and matrix, it is then possible to calculate the porosity of the side rock assuming that fluid density and matrix density are known along the well bore. The tool has yet to be fully implemented in Iceland. The latest addition to Iceland GeoSurvey logging services is a borehole video camera. The camera features a lens with a vertical view and a lens with a 360° view perpendicular to the side-wall. The high quality and resolution enables close inspection of the casing, allowing estimation of precipitation rates or damage to the casing itself.

3.8 Special Case Scenarios

When endeavors are made to reach and tap the geothermal reservoir not everything always goes according to plan. Several well-known scenarios can occur while drilling, which has to be dealt with accordingly. If HT steam or high pressurized gases enters the well while drilling the risk of blow-out is great. The risk for underground blow-out is addressed by the drillers having fitted the well-head with the relevant blow-out preventers (BOP's) but on occasion careful interpretation of temperature logs might enable the loggers on-site to give the drillers an early warning.

Extreme acidic fluids have been encountered in Krafla field, where wells are drilled in close vicinity to the underlying magma and in the Reykjanes field, where mixing of meteoric water with a seawater component, makes the geothermal fluid extremely corrosive to most known metals and alloys used in drilling and logging applications (**Table** 2). It is obviously not feasible to change the fluid composition and thus measures have to be taken to deal with the problem of very corrosive geothermal fluids, Vaughn and Chaung (1981). These measures are still a work in progress.

An increase in stuck drill pipe has been seen with an increase of deviated wells being drilled and more pressure on drillers to deliver completed wells in less time. The problem usually arises when the well collapses on the drill string. In other words, a sudden pressure drop in the well makes the drill cuttings in suspension settle very quickly around the drill string. To deal with the issue when the drillers has been giving two to three days (as stipulated in the C&C contract) the normal procedure for Iceland GeoSurvey is to run a combined temperature and CCL tool. It is in itself a very simple but effective way to locate the fish but it also gives information to the loggers as to where joints are situated and thus it can be decided where to place explosives (C4) if there's no other option than to back-off. More advanced tools such as the Free Point tool (FPT) exist and will most likely be added to Iceland GeoSurvey logging services in the near future. The basic idea of the FPT is to measure the torque or stretch on the drill string and thus enabling the logger to establish the deepest point of where the string is not stuck. Another well known problem often arises when drilling away from vertical (deviated) and that is a so-called key-hole. What can happen is that the well bore becomes increasingly ellipsoid (rather than circular) if the drill string starts to rub against the well bore. In some extreme cases this means that the drill string gets stuck when the drillers are trying to POOH (pull out of hole).

Table 2: Concentrations in steam from Krafla and Reykjanes geothermal fields

Steam concentration	CL	CO_2	H_2S	pH	Max. recorded T (°C)
Reykjanes* (mg/L)	18000 - 20000	1000-2000	20-60	4.6	340
Krafla (mg/kg)**	1,6-250	3557	587	4.3	386

*Reykjanes: based on analyses from some 20 high-temperature wells.
**Krafla: based on analysis from one well but more wells are known to be of similar chemical composition. This particular environment becomes very corrosive when HCL begins to condensate from the steam.

Eventually the increase in logging also means increased risk of LIH. If the loggers do not succeed themselves in fishing the lost tool the drillers will go in with a suitable fishing tool on the drill string, trying to hook the logging tool. When everything fails and the fish is deemed lost for good the drillers will go down with milling equipment and remove the fish. When metal shards stop appearing in the drill cuttings, the normal routine of drilling can continue.

In the last years experiments have been made with stimulating wells while the drill rig is still on-site and thus using very powerful pumps and vast amounts of water, Steingrimsson and Gudmundsson (2006). As a rule, the stimulation is proceeded by a short step-test prior to the "real" transient step-test program. That way it is possible to evaluate improvement of injection, if any. In many cases an increase in the injectivity index has been seen but the data is not conclusive and more studies need to be done on the validity of spending valuable rig time on stimulation. Presently one contractor (RE) in Iceland is using coiled tubing to stimulate the well after the rig has been moved, saving at lot of money and seemingly getting much the same stimulation results.

When a well has been completed all measurements and activities surrounding the drilling and logging are collected in a number of final reports, usually one for each drilling stage. Here all relevant information concerning a given well in a certain stage of drilling are tied together, and the interpretation of the lithology is especially elaborated on. This means correction of data and, as mentioned in the above, adjusting depth zero to ground level.

4. WELL MONITORING AND TESTING

During drilling, mud and cold water are used for circulation and cooling and therefore temperature in the well at the end of drilling is much lower than that of the surrounding reservoir. Due to heat conduction the temperature begins to rise as soon as pumping is stopped. The warm-up period for a given well to reach equilibrium can be as long as several months. During this time measurements of water table and well head pressure are monitored. Furthermore down-hole temperature and pressure measurements are done by using HT Dewar flask electronic memory temperature and pressure tools. The standard at Iceland GeoSurvey for decades has been the mechanical tools from either Amerada or Kuster but recently data quality and resolution has increased immensely with the addition of the K10 Geothermal tool from Kuster Co., Danielsen (2008), to our HT logging tool services.

During recovery the water in the well expands as is warms up, indicated by increased well head pressure. Logging down-hole temperature provides data to estimate the true formation temperature as a function of depth. The down-hole pressure log will indicate where the well is best connected to the reservoir (pivot point), Steingrimsson and Gudmundsson (2006).

When recovery has been reached it is necessary to perform discharge or flow tests to determine the well characteristics and the chemistry of the fluid discharged from the well. Testing of flowing wells is in principle very similar to testing when injecting cold water. Three steps are usually taken controlled by either closing the main valve in small steps or opening it, depending on well performance.

Not all wells are production wells and a major issue is to re-inject into the geothermal reservoir both in order to replenish the reservoir but also for environmental reasons. Preliminary results (not yet published) from tests done in two injections wells owned by RE indicate that the injectivity index is highly influenced by the temperature of the injected fluid. Early results indicate a nearly linear relation between temperature and injectivity index, Kristjánsson and Gunnarsson (2009).

5. LONG-TERM PLANNING

As previously mentioned, the need for standardization is as great as ever and part of the effort needed in establishing this is a rigorous evaluation program where long term planning and re-assessment of applied tools, techniques, appliances and procedures, plays a critical role.

6. CONCLUSIONS

Abundant work is already at hand, for example Franzson et al. (2001), Mostagel (1999) and Waagestein et al. (2003) as referred to in this paper as well as many others, but the need for work on standardized interpretation and correlation of lithological logs of volcanic rocks in geothermal settings as Rider (1991) has done on sedimentary rocks for the oil industry, is pressing.

In case of exploring for low temperature fields heat flow measurements are also important as well as geophysical methods to detect water-bearing fractures. The exploratory work leads to a conceptual model of the geothermal field to be tested by exploratory drilling, Mortensen and Flovenz (2008).

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The role of well testing in geothermal resource assessment

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60 ECTS thesis submitted in partial fulfilment of a
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Abstract

In this thesis, different approaches and methods for analysing well test data to estimate the capacity of a geothermal field are evaluated. The thesis lays emphasis on well completion and flow tests data, and uses the Reykjanes geothermal field in southwest Iceland as an example for the application of the selected methods. Analyses of data from step-rate injection tests, temperature and pressure profiles as well as discharge tests conducted in the Reykjanes geothermal field are presented. Six wells, RN-12, RN-13b, RN-17b, RN-18, RN-23 and RN-29 were selected for the study. The computer numerical software, Well Tester, is used for the step-rate injection test analysis. Temperature and pressure profiles are analysed to estimate the formation temperature and the initial reservoir pressure. Flow characteristics are evaluated from the lip pressure method and the steam-water separator method, respectively. The wellbore simulator, HOLA, is used to evaluate the generating capacity and productivity indices of individual wells. The injectivity and productivity indices are compared with results from other similar high temperature geothermal fields. The volumetric method based on well test data is applied to predict the electrical generation capacity of the Reykjanes geothermal system. The estimated values of permeability-thickness from the injection tests range from 1 Dm to 30 Dm, whereas the storativity ranges from $5 \cdot 10^{-8}$ m/Pa to $2 \cdot 10^{-7}$ m/Pa. The reservoir temperature estimate is between 280 °C and 340 °C. The average capacity for producing electricity is estimated around 10 MW_e per well. The resource assessment is performed for two cases. Case I considers the surface alteration area of the Reykjanes field of 2 km^2 while case II considers the low resistivity sheet at 1000 m depth b.s.l. of an area of 11 km^2. The Monte Carlo simulation for case I predicts with 90% confidence interval a generating capacity between 34 MW_e and 102 MW_e for a recoverable heat, with a most likely value of 65 MW_e and between 20 MW_e and 61 MW_e with a most likely value of 39 MW_e for 30 years and 50 years, respectively. For case II, the simulation predicts with 90 % confidence interval a generating capacity between 38 MW_e and 290 MW_e with a most likely value of 132 MW_e and between 23 MW_e and 174 MW_e with a most likely value of 79 MW_e for 30 years and 50 years, respectively.

To my wonderful mother,

The best and strongest woman in my life,
Thank you for making me who I am today.

To my beautiful children,

My precious gift,
Always keep in mind that you can achieve whatever you want in life.
Believe in yourselves, work hard and treasure true friendship.

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Nomenclature

A = Cross-section area of the lip (cm^2);

C = Wellbore storage coefficient (m^3/Pa);

c= Compressibility (Pa^{-1});

E = Heat energy (kJ);

g = Gravity (m/s^2);

H = Fluid enthalpy (kJ/kg);

h = Thickness (m);

II = Injectivity index ((L/s)/bar);

k = Intrinsic permeability (m^2);

k_r = Relative permeability of the phases (m^2);

L = Power plant capacity factor (%);

m = Slope of semi logarithmic straight line;

p = Pressure (bar-g);

P= Power plant capacity (MW_e);

P_c = Lip pressure (bar-a);

p_D = Dimensionless Pressure;

p_e= Pressure at outer boundary(bar-a);

PI = Productivity index ((kg/s)/bar);

q = Volumetric flow rate (m^3/s);

q = Production or injection flow rate (kg/s)

Q_{feed} = Mass flow rate at feedzone (kg/s);

r = Radial distance (m);

r_D = Dimensionless radius (m);

r_e = external boundary radius (m);

R_f = Recovery factor;

r_w = Wellbore radius (m);

S= Steam saturation;

S = Storage coefficient or Storativity (m/Pa);

s = Skin factor;

T = Temperature (°C);

T = Transmissivity (m^3/Pa s);

t = Time (s);

t_D = Dimensionless time based on well bore radius;

V = Volume (m^3);

W= Water level (m);

X = Steam mass fraction ratio;

z = Vertical coordinate (m);

φ = Porosity;

μ = Dynamic viscosity (Pa s);

ρ = Fluid density (kg/m^3);

η = Conversion efficiency (%).

Subscripts

s = Steam

t = Total

w = Water

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1 Introduction

The exploration and development of a geothermal resource is divided into several phases starting with preliminary studies or surface exploration, drilling, reservoir evaluation and finally the resource utilisation involving the extraction of mass and heat from the geothermal reservoir. Reliable information about a given geothermal reservoir is important when deciding whether and how to exploit it in the best and most economical manner. To reach this decision, the deliverability (ability to produce) and the properties of the reservoir must be known.

Understanding the status and properties of a geothermal reservoir is of major importance for its development and management. This is achieved by combining well testing results with information from different disciplines (geology, geochemistry geophysics and drilling) through a comprehensive conceptual model. In Rwanda, the author's home country, the development of geothermal resources is in its early stages and it has reached a point where drilling needs to be carried out to prove the existence of a geothermal potential. For the Government of Rwanda, the exploitation of geothermal resources is currently a high priority. Drilling of the first three exploration wells is planned for the year 2012. The future plan is to use well head generating units to immediately generate power if exploration wells are successful. This requires having a clear picture of the reservoir characteristics and properties. Testing of the wells will provide key reservoir parameters for field development decisions.

Well testing is the first step in evaluating the energy that can be extracted from a given reservoir. Well tests or pressure transient tests after well completion and during discharge are performed in order to estimate wellbore and reservoir properties such as permeability, the initial reservoir pressure, the reservoir limits, the well productivity, etc. These estimates are important for field development decisions. During a well test, the temperature and the pressure response of a reservoir to changing production (or injection) conditions are monitored. The pressure can be measured in the well where the flow rate has been changed or in neighbouring wells (Horne, 1995). Downhole tools allow measurements of temperature and pressure in the wells at different depths to estimate the formation temperature and the initial reservoir pressure. Discharge tests after warm up of the well is key to estimate the deliverability of the well which determines the success of the well. During the energy production from a geothermal reservoir, monitoring data are collected to continuously upgrade the picture of the reservoir. All this information is essential for a successful reservoir assessment.

Through the history of geothermal exploration and development, several techniques have been applied to assess and manage geothermal resources all over the world ranging from simple correlation to detailed modeling. The capacity of a geothermal field can be determined by its size, heat content or production response. The first assessment of a geothermal field capacity is usually done by a volumetric method (Muffler and Cataldi, 1978) which involves estimating the energy production potential of a geothermal system based on size and temperature conditions. Other methods like the lumped parameter modeling (Axelsson, 1989) can simulate the pressure response to production of a reservoir and give a better estimate based on available data during production. More complicated assessment such as numerical modeling requires large amounts of field data to understand the nature of the system.

In this study, the following research questions were asked: What are the current approaches and methods used in well testing? What kind of information is expected at different stages of well testing and how can this information contribute to the development of a new geothermal field? How can the results of well testing be used to estimate the production capacity of a geothermal field? How can the results be used in guiding decision making for the development of a field? The purpose of this thesis is to answer some of these questions using data from wells in the Reykjanes geothermal field as an example.

Chapter 2 of this thesis outlines the theoretical background of basics aspects of well testing. The main interpretation methods for well testing are presented in Chapter 3. Well data from step-rate injection tests are modelled using a numerical software Well Tester (Júlíusson et al., 2008) to estimate reservoir and well properties as well as the injectivity indices (Chapter 4). Pressure and temperature profiles are analysed and interpreted to estimate the formation temperature and the initial reservoir pressure as well as to locate the feed zones (Chapter 5). Lip pressure and steam separator discharge tests are used to estimate the flow characteristics and the productivity indices of selected wells. The results from the discharge tests are simulated using the wellbore simulator HOLA (Björnsson et al., 1993) to evaluate the generating capacity and productivity indices of the feed zones of individual wells. Injectivity and productivity indices are then compared to estimate a relationship between the two (Chapter 6). A resource assessment is carried out to estimate the reserves of the Reykjanes geothermal field from well test data (Chapter 7). Chapter 8 presents the conclusion of the thesis. Appendix A presents detailed results and graphs for Chapters 4 to 7.

2 Resource characterisation by well testing

The goal of the first chapter is to introduce various terminologies and give a theoretical background on aspects of well testing. In Section 2.1 and 2.2, a general introduction to geothermal resources and reservoirs is given. Definition and different aspects of well testing are introduced in Section 2.3. Overview information of the data source, the Reykjanes geothermal field, used for the methodology in the thesis is given in Section 2.4.

2.1 Generalities

Geothermal energy is the natural heat contained within the Earth that can, or could, be recovered and exploited. Heat flows from the interior of the earth to the surface either by convection through hot water mass transfer or by heat conduction. The most obvious manifestations of the Earth's thermal energy are in areas of recent volcanism and tectonic activity. Therefore, the temperature increase with depth, the volcanoes, geysers, hot springs, etc., are in a sense the visible or tangible expression of the heat in the interior of the Earth, but this heat also engenders other phenomena that are less discernible by man. Geothermal resources are distributed throughout the world and the greatest concentration of geothermal energy is in volcanic regions but may also be found as warm ground water in sedimentary rocks.

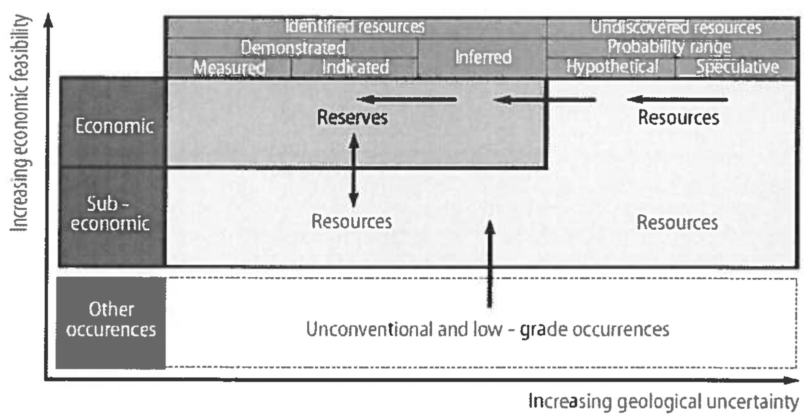

Figure 2.1: McKelvey diagram (modified from Goldemberg et al., 2000).

According to Muffler and Cataldi (1978), a geothermal resource is what should more precisely be called the accessible resource base; that is, all of the thermal energy stored between the Earth's surface and a specified depth in the crust, beneath a specified area and measured from local mean annual temperature. The accessible resource base includes the useful part (Resources) which could be produced at a price which will become competitive with other types of energy within a reasonable period of time. This category includes the identified economic resource (Reserves), part of the resources of a given area that can be extracted legally at a cost competitive with other commercial energy sources and that are known and characterised mostly by drilling. Those terminologies are easily illustrated through a modified McKelvey diagram (Figure 2.1) in which the degree of geological assurance regarding resources is set along the horizontal axis and the economic feasibility (effectively equivalent to depth) is set along the vertical axis (Muffler and Cataldi, 1978).

2.2 Geothermal reservoir

A geothermal reservoir or reserves is usually defined as the section of an area of geothermal activity that is hot and permeable so that it can be exploited economically for the production of fluid and heat (Grant and Bixley, 2011). In other words, a geothermal reservoir needs a heat source, magma or geopressure; it needs to be confined in an aquifer and usually a caprock to hold the hot fluid in place. A schematic figure of a composite model of a geothermal reservoir is represented in Figure 2.2.

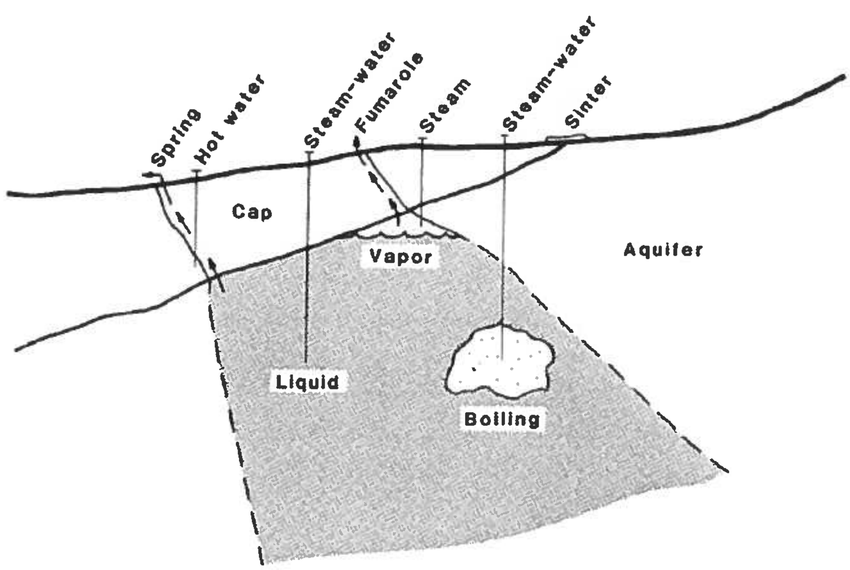

Figure 2.2: Schematic representation of a composite model of a geothermal reservoir (Gudmundsson, 1986).

Geothermal reservoirs have been classified in different ways (Bödvarsson, 1964; Axelsson and Gunnlaugsson, 2000). It is therefore of importance to define here the terminology that is in use to classify reservoirs:

- **Low temperature and high temperature reservoirs:** Low temperature geothermal systems have a base reservoir temperature below 150 °C, and high temperature systems have reservoir base temperatures above 200 °C. The intermediate system between these two systems has a base temperature between 150 °C and 200 °C. It is a medium temperature geothermal system.

- **Liquid-dominated and vapour-dominated reservoirs:** Geothermal reservoirs are conveniently categorised as either vapour dominated or liquid dominated. In each case the name refers to the phase which controls the pressure in the reservoir in its undisturbed state. When one phase is dominant, the other phase may also be present and partly mobile. A reservoir where steam and water co-exist is called a two-phase geothermal reservoir. It has to be pointed out that in high temperature geothermal reservoirs, a decline in pressure caused by exploitation may initiate boiling in parts of the entire reservoir making a liquid dominated reservoir become a two-phase reservoir.

Geothermal reservoirs are in general more complex than petroleum and groundwater reservoirs, often requiring complicated approach. Geothermal reservoir engineering or physics is the scientific discipline that deals with fluid flow and energy transfer in geothermal systems (Axelsson, 2010). The main aim of geothermal reservoir physics is to evaluate the magnitude of the resource and the size of electric or thermal power plant that can be supported by a field over a designated project life usually in the range of 20 to 30 years. In order to address this, the reservoir engineer must undertake different field tests and analyses including (Bödvarsson and Witherspoon, 1989):

- Conducting temperature and pressure surveys to obtain information on the reservoir rocks and the feed zones properties,
- Interpreting well tests to evaluate the reservoir characteristics,
- Evaluating flow rates and enthalpies of producing wells to determine the deliverability of the wells,
- Evaluating performance of injection tests,
- Estimating reserves.

These steps are reviewed in Chapter 4 to Chapter 7.

2.3 Basics of well testing

The first step for a reservoir engineer is to estimate the relevant reservoir and wellbore parameters by a transient pressure test. This information is needed to confirm whether a well is satisfactorily drilled and to decide how to exploit the reservoir. The important reservoir and wellbore parameters are the permeability, the formation storage (or the storativity), the skin factor and the wellbore storage. The type of reservoir (porous or fractured) and the type and location of the reservoir boundaries are also important. Based on the well test objectives, several kinds of tests may be designed to determine these parameters and reservoir properties.

The following sub-sections describe the procedure of well testing (2.3.1), the reservoir and well properties (2.3.2) and the type of tests (2.3.3).

2.3.1 Well testing description

A well test is a fluid flow test conducted in wells to obtain data and information on the properties of the reservoir and the well. Well tests are done before exploiting the reservoir, but also after a period of production, to see whether and how much the reservoir properties have changed.

During a well test, the temperature and the pressure response of a reservoir to changing production (or injection) conditions are monitored. The pressure can be measured in the well where the flow rate has been changed or in neighbouring wells (Horne, 1995). Since the pressure response depends on the properties of the reservoir, it is possible to deduce various reservoir properties from the pressure response.

In practice, well testing (or pressure transient tests) consists essentially of changing the well's flow rate by fluid production from or injection into the well and measuring the well's response as a function of time. The shape of the reservoir response can then be matched against a library of type curves to identify a suitable reservoir model. Finally the model is fitted to the data and the reservoir and well parameters deduced from the model. To do so a mathematical model is built to describe the fluid flow in the reservoir/well system (Horne, 1995; Bourdarot, 1998). The procedure is illustrated in Figure 2.3. The foundation of this mathematical model is the pressure diffusion equation which describes isothermal single phase flow of a fluid through a homogeneous porous medium. To date, many methods have been proposed for the interpretation of transient tests and Chapter 3 is dedicated to the description of these methods.

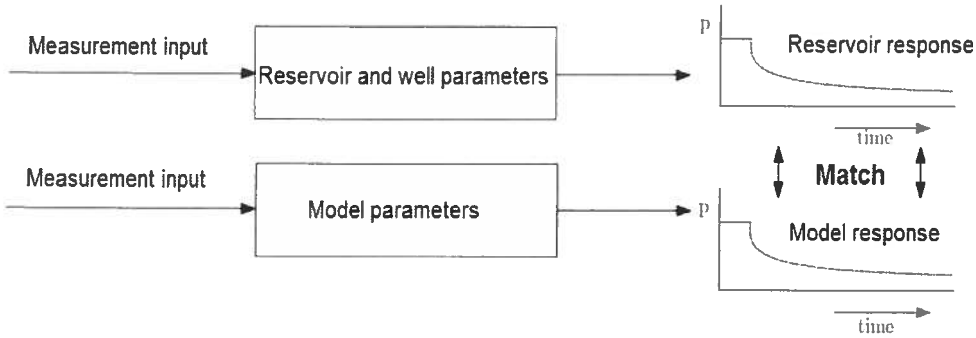

Figure 2.3: Well testing procedure (Horne, 1995).

2.3.2 Relevant reservoir and well properties

As already mentioned, the purpose of well tests is to determine reservoir and well properties. In this sub-section, the important reservoir and well properties are briefly defined and described.

Permeability of reservoir rocks

The permeability, k, controls the ability of the reservoir to transmit fluid. The higher the permeability, the easier it is for the fluid to flow through the rock matrix. In a geothermal reservoir, the fluid has to flow through the reservoir and for that reason the permeability of the rock is an important characteristic. The pressure response of the reservoir is very sensitive to the permeability. The permeability is measured in the unit Darcy, D, or milliDarcy, mD, where 1Darcy is equivalent to $0.987 \cdot 10^{-12} m^2 \sim 10^{-12}\ m^2$.

In case of a two phase geothermal reservoir, steam/water, each phase has its own relative permeability, k_{rs} and k_{rw}. These permeabilities are dependent on the fluid saturation. It is conventional to plot both permeabilities as a function of the water saturation, S_w, alone since the steam saturation, S_s, is related to the former through the simple relationship, $S_s = 1 - S_w$ (Dake, 1978). For fractured geothermal rock it is often assumed that the phases impede that $k_{rs}+k_{rw} = 1$ (Grant and Bixley, 2011).

In most geothermal systems, well tests are influenced by fractures. Fracture permeability is much higher than the permeability of the rock matrix and it has to be encountered for during well testing. It is the transmissivity, T, which is the ability of an aquifer to transmit fluid, or the permeability-thickness, *kh*, that is determined during a test. It is therefore necessary to know the thickness of the reservoir to determine the reservoir permeability (Bourdarot, 1998).

According to Björnsson and Bödvarsson (1990), the permeability of most geothermal reservoirs ranges from 1 mD to 100 mD and the permeability- thickness, *kh,* from 1 Dm to 100 Dm (Darcy meter). Productive geothermal reservoirs have permeability-thickness, *kh* values of the order of 10 Dm or higher (Singhal & Gupta, 2010).

Reservoir storage capacity

The reservoir storage capacity or storativity, *S*, is another important characteristic of a reservoir since it is an indication of the fluid reserves in the geothermal reservoir. The reservoir storage capacity is defined as the volume of water released by unit volume of reservoir for unit drop in pressure (Kjaran and Elíasson, 1983). It controls the aquifer's capacity to store fluid. The reservoir storage capacity depends on the porosity and compressibility of both the rock matrix and the fluid.

In high temperature geothermal reservoirs, the fluid is often in two phases, liquid and vapour (Singhal & Gupta, 2010). Therefore, the storativity value of the reservoir will also depend on the relative proportions of these two phases. Since the compressibility of vapor is very large compared to that of the liquid, the value of the storativity will be large in a high temperature reservoir. Therefore, this does not necessarily mean a high porosity reservoir (Singhal & Gupta, 2010). However, the largest compressibilities occur in two phase reservoirs where the steam can be condensed into liquid water.

Wellbore Storage

Well testing measurements are commonly done at two locations: downhole and at the wellhead. In the latter case, an additional parameter, the wellbore storage, has to be considered when evaluating the reservoir system. When the well is opened to flow, the fluid at the surface is initially dominated by the expansion of the fluid stored in the wellbore and the reservoir contribution is initially negligible. Similarly, when a well is shut in, the flow rate will be zero at the top of the well, but not instantaneously at the bottom of the well, due to the compressibility of the fluid in the wellbore. In this case the wellbore storage effect is called after flow (Bourdet, 2002).

It has to be emphasised that the wellbore storage cannot be interpreted literally to give a wellbore volume. It should be considered as a nuisance effect that affects the form of the pressure transient curves. The wellbore storage is quantified in terms of a coefficient, *C*, which represents the volume of fluid that the wellbore itself will produce due to a unit drop of pressure (Grant and Bixley, 2011).

Skin effect and turbulence

Drilling of a well and well treatment operations cause changes of the reservoir characteristics in the vicinity of the well as compared to those further away in the reservoir. This effect is known as the skin effect. Mathematically, in a reservoir model, skin is represented as a region of increased or decreased permeability surrounding the wellbore (Figure 2.4). The skin factor, *s*, can be positive or negative. Positive skin (damaged well) means an increase in pressure drop and negative skin (stimulated well) means a decrease in pressure drop at the interface between the reservoir and the wellbore (Agarwal et al., 1970, Ramey, 1970). Productive geothermal wells usually display a negative skin factor. According to Horne (1995), the skin effect can be described in terms of an effective wellbore radius which is the radius that the well appears to have due to the reduction or increase in flow caused by the skin effect.

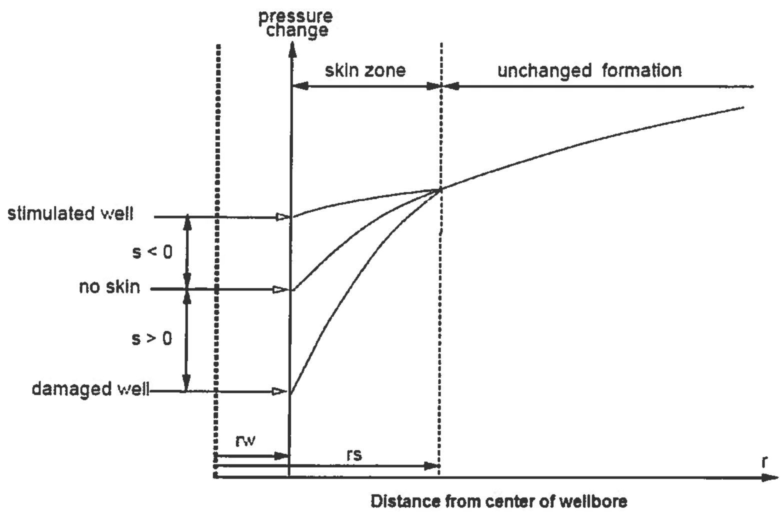

Figure 2.4: Pressure changes around a wellbore due to the skin effect (modified from Horne, 1995.

At high flow rates, or in fractured reservoirs, fluid flow tends to be turbulent, and Darcy's law (more details about Darcy's law can be found in Chapter 3) is no longer applicable. Skin due to turbulent flow or non Darcy flow is the additional pressure drop caused by high fluid velocity near the wellbore. Depending on the rate this effect can be significant and must be accounted for. It has to be noted that skin due to turbulence is always positive and is a part of the total skin. Thus, a production test on a stimulated well can still yield a positive total skin, *s,* value due to the turbulent component even if no skin damage is present.

Reservoir Boundaries

The size of the reservoir is important when estimating the amount of fluid recoverable from the reservoir. Therefore, the location and type of boundaries must be known. Two types of boundaries are most common, the closed and open boundaries.

According to Dake (1978) and Horne (1995), the closed or no-flow boundaries imply that there is no flow through the reservoir boundaries, the pressure perturbation associated with production from a well will be transmitted outward until it reaches all sides of the boundary and enters a state known as *pseudo-steady state*. The open boundaries mean that a constant pressure exists at the boundaries, that is, the reservoir is pressure supported by either an aquifer or by fluid injection. The effect of the constant pressure is known as *steady state*. Another intermediate state, *transient state* is usually observed before constant pressure or closed boundary effects are reached. In this case the reservoir behaves as if it was infinite for testing purposes. The more accurately the type and location of the boundaries can be predicted, the more accurately can the amount of recoverable fluid be calculated. The following schematic chart (Figure 2.5) shows the typical pressure responses for reservoir models with different boundaries.

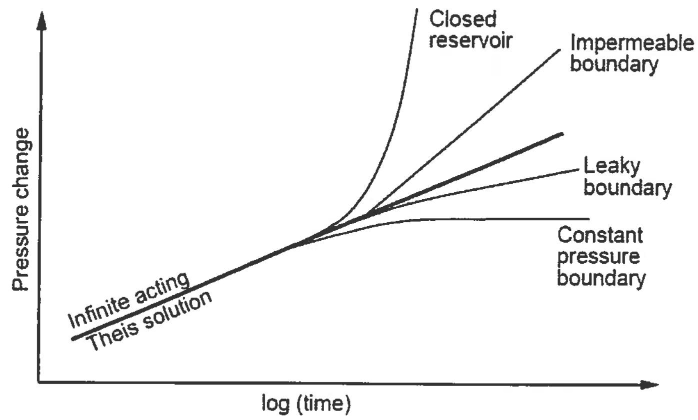

Figure 2.5: Typical pressure responses for different reservoir models (Bödvarsson and Witherspoon, 1989).

2.3.3 Types of well tests

During conventional well tests, fluid is extracted to the surface or injected into the well at controlled rates. A program of flow and shut in periods is used to establish deliverability and completion efficiency of the well. Tests can involve a single well or many wells. Depending on test objectives and operational considerations, a range of well tests can be carried out. The tests usually fall into the following categories (Horne, 1995; Bourdet, 2002):

- *Build-up test*: This test is conducted in a well that has been producing for some time at a constant rate and is then shut in. The build-up downhole pressure is then recorded for a given time.
- *Drawdown test*: This test is conducted when a well is flowed at a constant rate. The flowing downhole pressure and the production rate are measured as functions of time and analysed to estimate the reservoir properties. The major difficulty of the drawdown is the inability to maintain a constant flow rate.
- *Injection test*: This test is identical to a drawdown test, except that the flow is into the well rather than out of it. Fluid is injected into the well at a constant rate and the injection rate and the downhole pressure are measured as functions of time.
- *Falloff test*: This test is analogous to a build-up test and it measures the pressure decline as a function of time subsequent to the shut in of an injection.

The combined response can be interpreted in a number of ways to estimate the permeability-thickness and the skin factor. Tests with more than one well are called *interference tests*. Interference tests investigate the reservoir properties and establish pressure connectivity between wells. Figure 2.6 illustrates the types of well tests defined here.

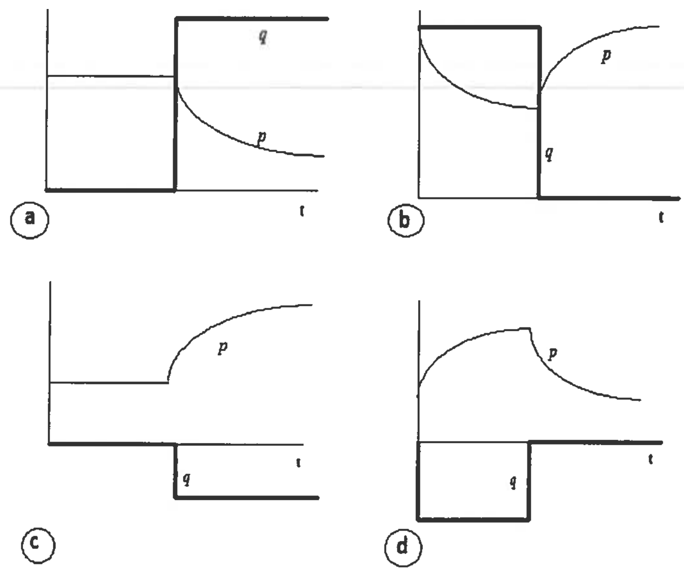

Figure 2.6: Types of well tests: a) Drawdown test, b) Build-up test, c) Injection test and d) Falloff test (Horne, 1995).

2.4 Geothermal well test data

Data from well tests in the Reykjanes geothermal field are used as an example for the application of the methodology used in the thesis. The Reykjanes geothermal system is located in the southwest of the Reykjanes Peninsula in southwest Iceland.

The exploration and development of the Reykjanes field dates back to several decades but the utilization was limited until 2006 when a 100 MW_e power plant was commissioned. The first well was drilled in 1956 to a depth of 162 m with a temperature of 185 °C (Gudmundsson et al., 1981). The fluid produced was a brine of seawater origin, different from rainwater commonly found in Icelandic hydrothermal systems (Sigurðsson, 2010). In the 1980's, nine wells were drilled from which two wells were used for a sea chemical plant (salt production) that was operational for only a few years. Today about 30 wells have been drilled in the area. The reservoir temperatures below 1 km depth range from about 275 °C to 310 °C and the fluid is hydrothermally modified seawater with some addition of magmatic gases (Arnórsson, 1978). The areal extent of geothermal surface manifestations is of the order of 2 km^2 (Pálmason et al., 1985). A resistivity survey carried out in the Reykjanes area shows a low resistivity anomaly with an aerial extension of 11 km^2 at 800 m to 1000 m depth b.s.l. (Karlsdóttir, 2005). Currently plans are made to expand the electrical power generation by adding a 50 MW_e turbine unit and possibly yet another 30 to 50 MW_e low pressure turbine unit (Sigurdsson, 2010).

Six wells in the Reykjanes geothermal field, RN-12, RN-13b, RN-17b, RN-18, RN-23 and RN-29 were selected for this study (see Table A.1). Figure 2.7 shows the location of the boreholes.

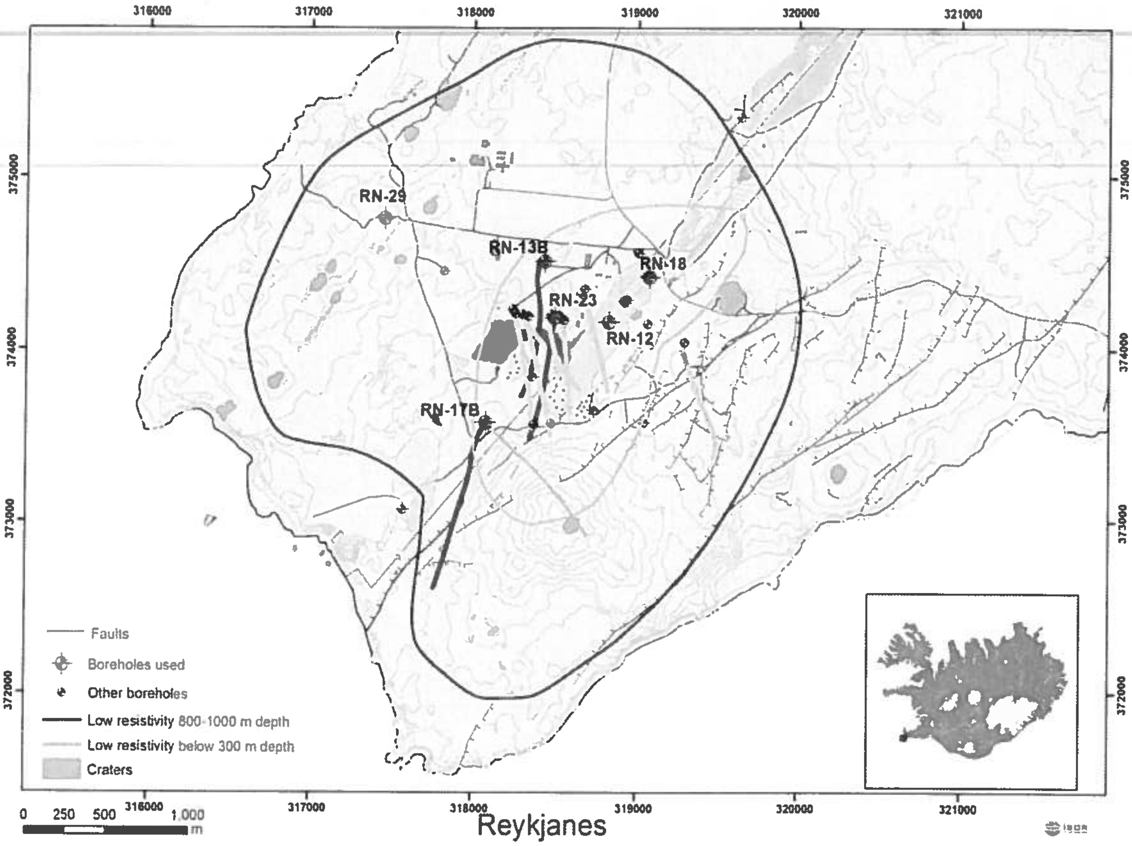

Figure 2.7: Reykjanes geothermal field and location of boreholes used in this study, shown in red. Low resistivity areas are from Karlsdóttir (2005) and craters, faults and alteration from Saemundsson et al. (2010).

3 Well test interpretation methods

The well tests and pressure transient analysis are conducted to evaluate the conditions of the wellbore and the reservoir to determine the parameters that characterize the reservoir. Therefore, a model is needed to interpret the measurements and link them to the reservoir properties. The founding principle of well testing is given by a physical equation, the pressure diffusion equation. The diffusion equation describes the spatial and temporal variations of pressure due to production or injection which is a diffusive process. The solutions of this equation give the expected outcome of the measurements of the well test (Horne, 1995).

Methods to analyse a well test are generally classified into two main groups: conventional methods and methods using type curves. All these methods depend on the type of well and reservoir as well as reservoir boundaries and can provide information on the size and shape of the formation and its ability to produce fluids.

In the following, the derivation of the pressure diffusion equation is discussed in Section 3.1 and some solutions of the diffusion equation are given in Section 3.2. Finally, the well test interpretation methods are reviewed in Sections 3.3 to 3.6.

3.1 Derivation of the pressure diffusion equation

The pressure diffusion equation is used to calculate the pressure, P, in the reservoir at a certain distance, r, from a production well producing fluid at a given volumetric flow rate, q, or mass flow rate Q equivalent to, $\rho \cdot q$ where ρ the fluid density, as a function of time, t (Horne, 1995; Grant and Bixley, 2011). It is important to emphasise here that $q > 0$ when producing from the well and $q < 0$ when injecting into the well.

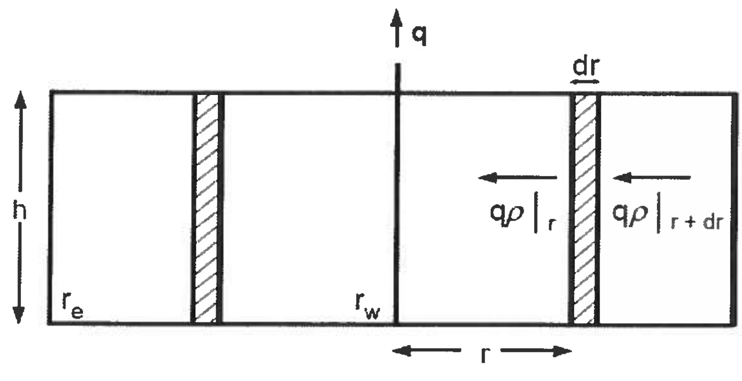

Figure 3.1: Radial flow of a single phase fluid in the vicinity of a producing well (Dake, 1978).

The pressure diffusion equation is derived using a simple model of a single phase fluid flow in a porous medium through a vertical well, circular in cross section that fully penetrates a uniform horizontal aquifer of infinite radial extent that is sealed above and below (Figure 3.1). The reservoir is considered homogeneous in all rock properties. The permeability of the reservoir is considered constant and isotropic (uniform physical properties in all directions). The fluid is uniform and of constant compressibility. The formation is completely saturated with a single phase fluid (Horne 1995). Two governing laws and one equation of state are used in deriving the pressure diffusion equation (Earlougher, 1977; Dake, 1978; Horne, 1995; Grant and Bixley, 2011).

Considering the flow through a cylindrical shell of an infinitesimal thickness, *dr*, situated at a distance, *r*, from the centre of the radial cell. Then applying the principle of mass conservation (1), the Darcy's law (2), and the basic thermodynamic definition of isothermal compressibility (3) (Dake, 1978), we have:

1. Conservation law of mass inside a cylindrical shell around the well:

Mass flow rate in – Mass flow rate out = mass rate of change

$$(q\rho)_{|r+dr} \quad - \quad (q\rho)_{|r} \qquad = 2\pi rhdr\frac{\partial(\varphi\rho)}{\partial t}$$

where $2\pi rhdr$ is the volume of the cylindrical shell of thickness *dr*. The left hand side of this equation can be expanded as (Dake, 1978):

$$\left((q\rho)_{|r} + \frac{\partial(q\rho)}{\partial r}dr - (q\rho)_{|r}\right) \quad = 2\pi rhdr\frac{\partial(\varphi\rho)}{\partial t}$$

This simplifies to:

$$\frac{\partial(q\rho)}{\partial r} = 2\pi rh\frac{\partial(\varphi\rho)}{\partial t} \tag{3.1}$$

where, q is the production (or injection), φ is the medium's porosity, h is the reservoir thickness, ρ is the fluid density and r is the distance from the centre of the well.

2. Darcy's law:

Darcy's Law is an equation that describes the flow of a fluid through a porous medium. It is the most fundamental law used in well testing. In differential form it relates the flow rate, q, across a surface to the pressure gradient, $\partial p/\partial r$, across its section.

In the radial (axial) form, the flow rate is:

$$q = 2\pi rh\frac{k}{\mu}\frac{\partial p}{\partial r} \tag{3.2}$$

where, k is the reservoir permeability, μ the dynamic viscosity of the fluid and p is the pressure.

By substituting the flow rate (3.2) into equation (3.1), we get:

$$\frac{\partial}{\partial r}\left(2\pi rh\frac{k}{\mu}\frac{\partial p}{\partial r}\rho\right) = 2\pi rh\frac{\partial(\varphi\rho)}{\partial t}$$

This simplifies to:

$$\frac{1}{r}\frac{\partial}{\partial r}\left(r\rho\frac{k}{\mu}\frac{\partial p}{\partial r}\right)=\frac{\partial(\varphi\rho)}{\partial t} \tag{3.3}$$

3. Equation of state for isothermal compressible fluids:

In the diffusion equation, the pressure differences between two locations in the reservoir are essential. These differences would not be there without compressibility. All the information from well testing is obtained because the porous medium and the fluids are compressible (Dake, 1978).

The basic thermodynamic definition of isothermal compressibility is given by:

$$c_w=-\frac{1}{V}\left(\frac{\partial V}{\partial p}\right)$$

where, c_w is the fluid compressibility and V is the fluid volume. Since $\rho=\frac{m}{V}$ where m is the mass of fluid, the isothermal compressibility can be expressed as:

$$c_w=\frac{1}{\rho}\left(\frac{\partial \rho}{\partial p}\right)_T \tag{3.4}$$

The right hand side of equation (3.3) can then be written as:

$$\frac{\partial(\varphi\rho)}{\partial t}=\rho\frac{\partial\varphi}{\partial t}+\varphi\frac{\partial\rho}{\partial t} \tag{3.5}$$

From equation (3.4), it can be shown that (Bear, 1979):

$$\varphi\frac{\partial\rho}{\partial t}=\varphi c_w\rho\frac{\partial p}{\partial t} \tag{3.6}$$

and,

$$\rho\frac{\partial\varphi}{\partial t}=(1-\varphi)c_r\rho\frac{\partial p}{\partial t} \tag{3.7}$$

where, c_r is the compressibility of the rock matrix. Inserting equations (3.6) and (3.7) into (3.5) gives:

$$\frac{\partial(\varphi\rho)}{\partial t}=\rho c_t\frac{\partial p}{\partial t} \tag{3.8}$$

where, c_t is the total compressibility of the system defined as $c_t=\varphi c_w+(1-\varphi)c_r$

By inserting (3.8) into (3.3) and expanding the left hand side of (3.3) assuming that the reservoir is homogeneous and therefore variations in ρ, k and μ are small, we can express the pressure diffusion equation as:

$$\frac{1}{r}\frac{\partial}{\partial r}\left(r\,\frac{\partial p}{\partial r}\right) = \frac{\mu c_t}{k}\frac{\partial p}{\partial t} \tag{3.9}$$

By introducing the parameters:

$$T = \frac{kh}{\mu} \quad \text{and} \quad S = c_t h$$

where T is the transmissivity and S is the storativity, equation (3.9) can be rewritten as:

$$\frac{1}{r}\frac{\partial}{\partial r}\left(r\,\frac{\partial p}{\partial r}\right) = \frac{S}{T}\frac{\partial p}{\partial t} \tag{3.10}$$

Equation (3.9) is the basic equation for well test analysis. In principle, an infinite number of solutions of equation (3.9) can be obtained depending on the initial and boundary conditions imposed (Dake, 1978).

In some liquid dominated reservoirs, the water table is measured instead of the pressure. In such cases, equation (3.9) can be rewritten as follows:

$$\frac{1}{r}\frac{\partial}{\partial r}\left(r\,\frac{\partial W}{\partial r}\right) = \frac{\mu c_t}{k}\frac{\partial W}{\partial t} \tag{3.11}$$

with the water table $W = z + {}^{p}/_{\rho g}$ where, z is the elevation and g is the acceleration of gravity. In this case, the appropriate initial and boundary conditions must be formulated in elevation of the water table (Kjaran and Elíasson, 1983).

3.2 Solutions of the diffusion equation

An infinite number of solutions for the diffusion equation (3.9) can be obtained for different regimes depending on the initial and boundary conditions imposed. These boundary conditions are assumptions based on a prior knowledge of the reservoir. These regimes are the transient, semi steady (pseudo-steady) state and steady state regimes (Dake, 1978; Kjaran and Elíasson, 1983). The transient flow occurs before the pressure response shows the presence of a boundary. The steady state and pseudo-steady state represent two types of boundary effects; constant pressure and closed boundary, respectively.

3.2.1 Transient flowing regime

This condition is only applicable for a relatively short period after some pressure disturbance has been created in the reservoir. For the period that the transient regime is applicable it is assumed that the pressure response of the reservoir at the top of the wellbore is not affected by the presence of a boundary (Figure 3.2). Thus the reservoir radius, r_e appears infinite in extent and the pressure at outer boundary, p_e is equal to the initial pressure, p_i (Dake, 1978).

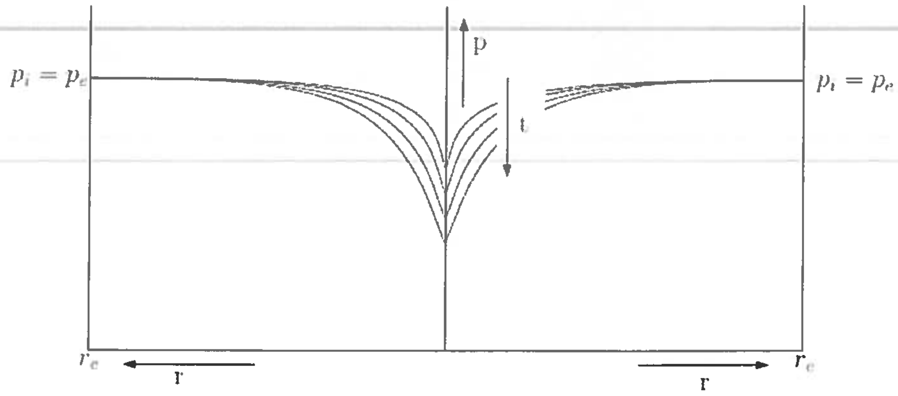

Figure 3.2: Pressure distribution under transient flow regime (modified from Dake, 1978).

The transient regime can be split up in two sub-regimes:

- **Wellbore dominated regime**. The wellbore dominated regime describes the very early part of the well test where the dynamics of the wellbore are dominating the reservoir dynamics in the pressure response. It is assumed that the pressure response in this regime does not contain any information about the reservoir, but only about the wellbore storage and skin.

- **Infinite flowing regime**. The infinite flowing regime describes the pressure response of the reservoir when the dynamics of the reservoir are assumed to be dominating the wellbore dynamics and there is no significant influence of the boundaries in the pressure response.

The most common solution of the diffusion equation for a transient flowing regime is described here. It is assumed that the wellbore is a line meaning that the wellbore radius, r_w is zero and the solution is often called the Theis solution (Theis, 1935) or the line source solution. To solve the pressure diffusion equation, one initial and two boundary conditions are needed. The initial condition describes the pressure state in the reservoir at a certain time while the boundary conditions describe the effect of the environment on the flow process. These conditions involve several assumptions and are therefore only valid for specific time intervals. For the Theis solution, the following initial and boundary conditions are assumed (Earlougher, 1977; Dake, 1978; Horne, 1995):

Initial condition: The pressure, p is the same all over the reservoir at time $t = 0$ and is equal to the initial pressure, p_i

$$p = p_i \quad at\ t = 0, for\ all\ r$$

Outer-boundary condition: The pressure is equal to the initial pressure at infinity

$$p = p_i \quad for\ r \rightarrow \infty, for\ all\ t$$

Inner-boundary condition: Darcy's law at the wellbore producing at constant rate q (equation 3.2):

$$\lim_{r\to 0}\left(r\frac{\partial p}{\partial r}\right) = \frac{q\mu}{2\pi kh} \quad \text{for } t > 0$$

In addition, the assumptions made in deriving the diffusion equation are the same as stated in the previous section. That is, the formation is homogeneous and isotropic, and drained by a fully penetrating well ensuring radial flow. The fluid properties are constant. Under these conditions, the line source solution of the diffusion equation known as the Theis solution (Theis, 1935) is given by:

$$p(r,t) = p_i + \frac{q\mu}{4\pi kh} Ei\left(\frac{-\mu c_t r^2}{4kt}\right) \tag{3.12}$$

where *Ei* represents the exponential integral function defined by:

$$Ei(-x) = -\int_x^{\infty} \frac{e^{-u}}{u} du \tag{3.13}$$

For small values of x (x < 0.01) the exponential integral *Ei* can be approximated by:

$$Ei(-x) \cong \gamma + \ln(x) \tag{3.14}$$

where $\gamma = 0.5772$ is the Euler's constant and ln is the natural logarithm. Therefore, for $> 100\frac{\mu c_t r^2}{4k}$, the Theis solution or line source solution is simplified and represented as:

$$p(r,t) = p_i + \frac{2.303\, q\mu}{4\pi kh}\left[log\left(\frac{\mu c_t r^2}{4kt}\right) + \frac{\gamma}{2.303}\right] \tag{3.15}$$

where $2.303 \approx \ln 10$ and log is the logarithm with base 10.

The Theis solution describes the pressure response with time, *t*, at location, *r*, from the wellbore given the inherent assumptions. The limitation of the Theis solution is for drawdown tests at the distance, *r* at time, *t* when producing at a constant rate, *q* and for unbounded boundaries. From this solution, it can be observed that by suitable observation of the pressure change, it may be possible to identify two important parameters: the permeability-thickness and the storativity (Earlougher, 1977; Horne, 1995).

At the active well, the skin factor is introduced as an extra pressure change. At an observation point or a well where the skin does not apply, the pressure drawdown can be defined as:

$$\Delta p_{well} = p_i - p_{no\ skin}(r,t) \tag{3.16}$$

The change in drawdown due to skin is defined by:

$$\Delta p_{skin} = \frac{q\mu}{2\pi kh} s \tag{3.17}$$

Therefore, the total drawdown at the wellbore ($r=r_w$) is then $\Delta p = \Delta p_{well} + \Delta p_{skin}$ and equation (3.15) can be rewritten as:

$$p(r_w, t) = p_i + \frac{2.303\, q\mu}{4\pi kh}\left[log\left(\frac{\mu c_t r_w^2}{4kt}\right) + \frac{\gamma - 2s}{2.303}\right] \quad (3.18)$$

3.2.2 Semi steady state regime

The semi steady state or pseudo-steady state flow is applicable to a reservoir which has been producing for a sufficient period so that the effect of the outer boundary has been noticed. This means that the pressure decline has struck impermeable boundaries all around the producing well. In terms of the radial flow model, the situation is illustrated in Figure 3.3 (Dake, 1978).

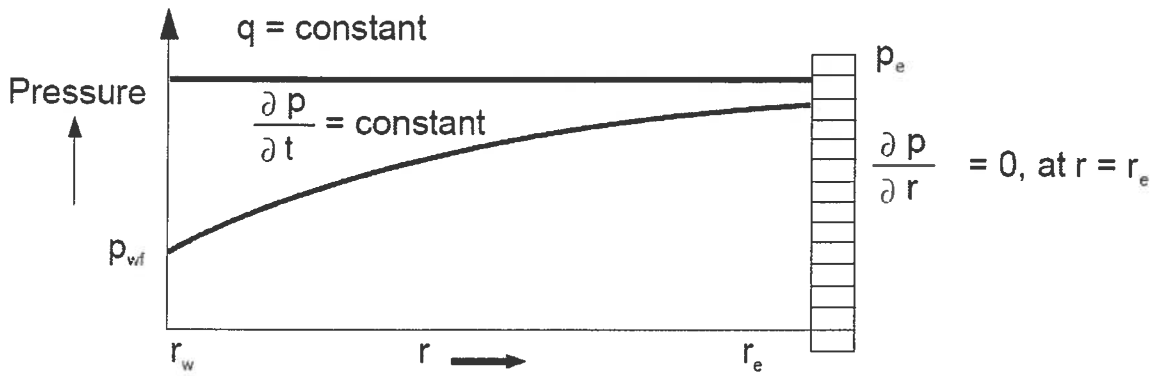

Figure 3.3: Pressure distribution under semi steady state regime, where r_e is the distance from the well to the boundary (Dake, 1978).

The first assumption is that at the outer boundary of the reservoir, in accordance with Darcy's law, the pressure gradient is zero meaning that there is no recharge in the system:

$$\frac{\partial p}{\partial r} = 0 \quad at\, r = r_e$$

The second assumption considers that, if the well is producing at a constant rate, the pressure will decline in such a way that the pressure derivative with respect to time is constant everywhere in the reservoir meaning that the system is closed.

$$\frac{\partial p}{\partial t} = \text{constant} \quad \text{for all r and t}$$

Using the definition of compressibility, the constant of the second assumption can easily be obtained as:

$$\frac{\partial p}{\partial t} = -\frac{q}{Vc_t} \quad (3.19)$$

in which V is the pore volume of the radial cell; q is the constant production rate and t is the total flowing time.

For a radial reservoir with radius r_e , the volume is $V = \pi r_e^2 h$, and the second assumption can be rewritten as:

$$\frac{\partial p}{\partial t} = -\frac{q}{c_t \pi r_e^2 h} \tag{3.20}$$

When substituting the equation (3.20) into (3.9), the diffusion equation becomes:

$$\frac{1}{r}\frac{\partial}{\partial r}\left(r\,\frac{\partial p}{\partial r}\right) = -\frac{q\mu}{kh\pi r_e^2} \tag{3.21}$$

The solution of the diffusion equation (3.21) for the semi steady state regime is then given by (Dake, 1978):

$$p(r,t) - p(r_w,t) = \frac{q\mu}{2\pi kh}\left(ln\frac{r}{r_w} - \frac{r^2}{2r_e^2} + \frac{r_w^2}{2r_e^2}\right) \tag{3.22}$$

Introducing the skin factor, we get:

$$p(r,t) - p(r_w,t) = \frac{q\mu}{2\pi kh}\left(ln\frac{r}{r_w} - \frac{r^2}{2r_e^2} + \frac{r_w^2}{2r_e^2} + s\right) \tag{3.23}$$

where $p\ (r,\ t)$ is the pressure at a distance r from the centre of the wellbore and $p\ (r_w,\ t)$ is the pressure at the wellbore with radius r_w at time t. The term $\frac{r_w^2}{2r_2^2}$ can be considered negligible since $r_w << r_e$ (Dake, 1978).

3.2.3 Steady state regime

The steady state regime is used when the pressure response does not drop anymore for example due to some displacing fluid leading to a constant pressure with time at the boundary (Figure 3.4). The steady state condition applies, after the transient period, to a well draining a reservoir which has a completely open outer boundary. It is assumed that, for a constant rate of production, fluid withdrawal from the reservoir will be exactly balanced by fluid entry across the open boundary and therefore (Dake, 1978):

$$p = p_e = constant, at\ r = r_e$$

and

$$\frac{\partial p}{\partial t} = 0\ for\ all\ r\ and\ t$$

The diffusion equation (3.9) then reduces to:

$$\frac{1}{r}\frac{\partial}{\partial r}\left(r\,\frac{\partial p}{\partial r}\right) = 0 \tag{3.24}$$

The solution of the diffusion equation for the steady state regime is known as the Theim solution (Theim, 1906) and is given by:

$$p(r) - p(r_w) = \frac{q\mu}{2\pi kh}\left(ln\frac{r}{r_w}\right) \tag{3.25}$$

With the introduction of the skin factor, this gives:

$$p(r) - p(r_w) = \frac{q\mu}{2\pi kh}\left(ln\frac{r}{r_w} + s\right) \tag{3.26}$$

Equation (3.25) determines a pressure difference as a function of the radius. The solution is independent of time (Dake, 1978).

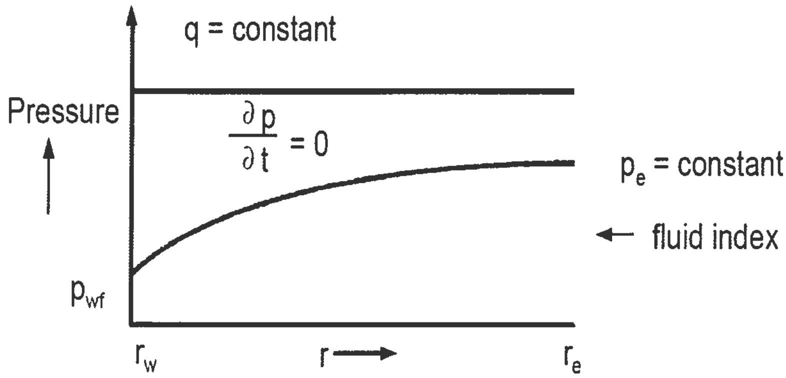

Figure 3.4: Pressure distribution under steady state regime (Dake, 1978).

It should be noted that the semi-steady state or the steady state conditions may never be fully realised in the reservoir during well tests. However, it is the solution of the transient flow regime (3.15) that is often used to interpret the well test data since it is the pressure disturbance for a relatively short period that gives the information on the reservoir (Dake, 1978).

3.3 Semi logarithmic analysis

During radial flow, the pressure change or drawdown is related to the logarithm of time. In other words, if the pressure is plotted against the log of time, infinite-acting radial flow (the intermediate time response between the wellbore storage and the boundary response) will give a straight line (Figure 3.5). The semi-logarithmic approach to well test interpretation is based upon plotting the pressure or the drawdown, p or Δp, versus time t, in a semi-logarithmic graph and identifying a straight line portion of the drawdown or build-up data, from which the permeability-thickness product, the storativity and the skin damage are obtained (Earlougher, 1977; Horne, 1995).

By rearranging (3.15) into the form $\Delta p = A + m \log{(t)}$, the pressure change or the drawdown, Δp can be plotted versus time on a semi logarithmic graph and a straight line portion of the graph with a slope, m is obtained as the pressure drop for one log-cycle (Horne, 1995):

$$m = \frac{2.303q\mu}{4\pi kh} \tag{3.27}$$

When the slope m is found according to equation (3.27), the permeability-thickness can be evaluated as:

$$kh = \frac{2.303q\mu}{4\pi m} \tag{3.28}$$

The storativity is obtained by using the value of the drawdown $\Delta p = p_i - p(r,t)$ at some particular time t and some value of r (usually r_w) from equation (3.15):

$$c_t h = 2.25 \left(\frac{kh}{\mu}\right)\left(\frac{t}{r^2}\right) 10^{-\Delta p/m} \tag{3.29}$$

In order to calculate the skin factor s, equation (3.18) can be used, isolating s from it. The value of $p\ (r_w,\ t)$ is read from the solid straight line with slope m. Often the time t equivalent to 1 hour is chosen but any point $(t,\ p\ (r_w,\ t))$ on the straight line can be used. In the later case, the constants in the formulas will change depending on the time value selected:

$$s = 1.151 \left[\frac{\Delta p}{m} - log\left[\left(\frac{4kh}{\mu}\right)\left(\frac{1}{c_t h}\right)\frac{t}{r_w^2}\right] + 0.251\right] \tag{3.30}$$

Note that the direct interpretation method is an indirect estimation method, since the step response has to be plotted first (Earlougher, 1977; Horne, 1995).

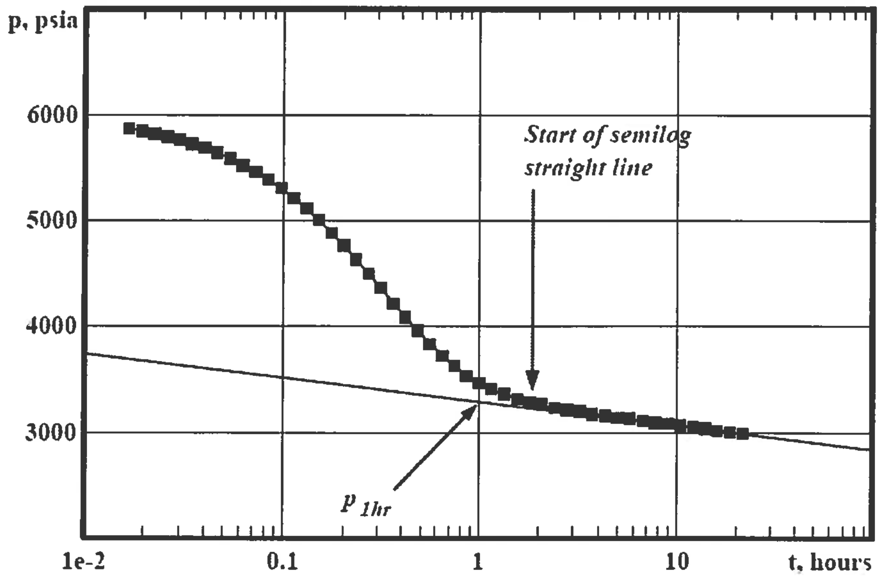

Figure 3.5: Semi log representation (Horne, 1995).

The best known and most commonly used semi-logarithmic analysis techniques or conventional methods are the *Miller-Dyes- Hutchinson or MDH plot* and *the Horner plot*.

The Miller-Dyes-Hutchinson, MDH plot (Miller et al., 1950) is strictly valid only for the first drawdown in a well, but in exceptional circumstances it can be used for the analysis of a later drawdown or a build-up test. It applies to wells that have reached pseudo-steady (semi-steady) state during injection. For the MDH plot, the pressure is plotted versus the logarithm of time, *log (t)*.

It is common to use the Horner plot to estimate the formation temperature (Horner, 1951; Dowdle and Cobb, 1975). The Horner plot is also the most used method and is more convenient for pressure build up tests (Horne, 1995). Pressure build-up tests require shutting in a production well. The effect of these two flow rates can be represented by a well which is produced for a time t_p, at rate q, and then shut in for a running time Δt. The pressure response is plotted versus log $((t_p+\Delta t)/\Delta t)$ on a semi-log plot. The superposition time $((t_p+\Delta t)/\Delta t)$ is known as the Horner time (Earlougher, 1977; Horne, 1995).

3.4 Dimensionless variables and type curve analysis

Another method for estimating the reservoir properties is to compare the plot of the measured pressure response with type curves. The type curve method (log-log method) was introduced in the petroleum literature by Ramey (1970) in an attempt to overcome the limitations of the semi-log straight line based analysis methods (Earlougher, 1977). To generalise the solution of the pressure diffusion equation, it is beneficial to transform the equation into a dimensionless form as it simplifies the reservoir models by representing the reservoir parameters independently of any particular unit system. Any variable can be made dimensionless by multiplying it by a group of constants with the opposite dimensions. These groups of constants depend on the reservoir parameters (Earlougher, 1977; Horne, 1995).

Dimensionless pressure $p_D\,(r_D, t_D)$,

$$p_D = \frac{2\pi kh}{q\mu}\Delta p \tag{3.31}$$

where $\Delta p = p_i - p_w$ and p_w is the pressure measured in the well

Dimensionless time t_D

$$t_D = \frac{kt}{c_t\mu r_w^2} \tag{3.32}$$

Dimensionless radius r_D

$$r_D = \frac{r}{r_w} \tag{3.33}$$

By defining dimensionless pressure and dimensionless time in this way, it is possible to create an analytical model of the well and reservoir, or theoretical type-curve log (p_D) versus log (t_D), that provides a description of the pressure response that is independent of the flow rate or of the actual values of the well and reservoir parameters. The data from the well test are plotted and the plot is compared with plots derived from theory. The reservoir properties are estimated by finding the best match (Horne, 1995).

The log-log type curve approach described here above is now somehow out of date in the industry compared to the semi-log approach, or the approach combining the log-log plot of Δp versus Δt with the pressure derivative where it is possible to make the entire analysis with a single plot. The pressure derivative approach is described in the following section.

The procedure for the type curve analysis (Figure 3.6) can be outlined as follows (Earlougher, 1977; Horne, 1995):

- The data are plotted as log Δp versus log (Δt) using the same scale as that of the type curve.
- The curves are then moved one over the other by keeping the vertical and horizontal grid lines parallel until the best match is found.
- The best match is chosen and the pressure and time values are read from some fixed point (match point) on both graphs, Δp_M, p_{DM}, Δt_M and t_{DM}.

For infinite acting system, the permeability-thickness and the storativity are given by the expression:

$$kh = \frac{q\mu}{2\pi}\left(\frac{p_D}{\Delta p}\right)_M \tag{3.34}$$

$$c_t h = \frac{kh}{\mu r_w^2}\left(\frac{\Delta t}{t_D}\right)_M \tag{3.35}$$

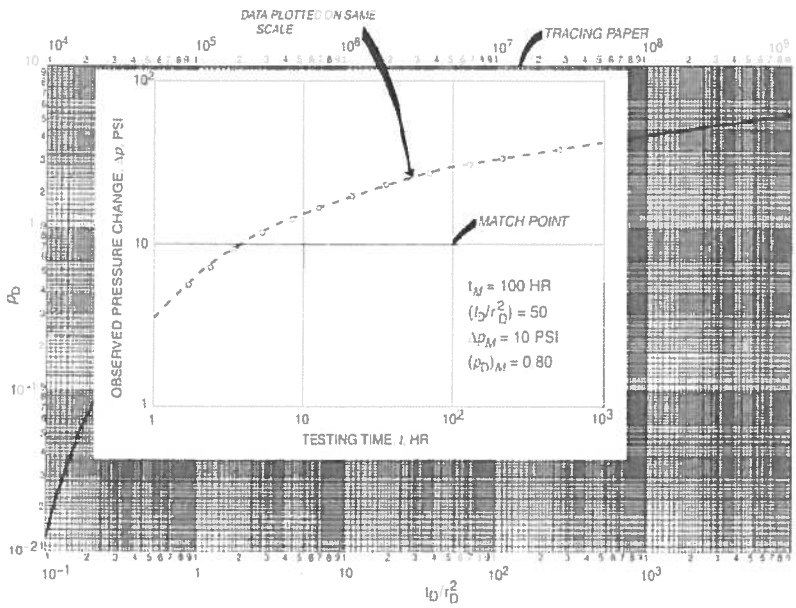

Figure 3.6: Illustration of a type curve matching for an interference test (Earlougher, 1977).

3.5 Pressure derivative plot

The introduction of the pressure derivative in the 80's by Bourdet and others (Bourdet et al., 1983; Bourdet et al., 1989) transformed the science of well test interpretation, which until that time had mostly been based on the semi-logarithmic plot and the type curve analysis. With the derivative approach, the time rate of change of pressure during a test period is considered for the analysis. In order to emphasise the radial flow regime, the partial derivative is taken with respect to the logarithm of time $\frac{\partial p}{\partial(\ln t)}$ which equals $t\frac{\partial p}{\partial t}$ (Bourdet et al., 1983). The derivative plot provides a simultaneous presentation of log (Δp)

versus log (Δt) and log $(t\frac{\partial p}{\partial t})$ versus log (Δt). The advantage of the derivative plot is that it is possible to display in a single graph many different characteristics that would otherwise require different plots (Horne, 1995).

Reservoir permeability, wellbore storage and skin can be determined directly using the measured curve and its derivative provided that the stabilization of the derivative has been reached. When the flow at early time corresponds to pure wellbore storage, pressure and pressure derivative curves will merge on a unit slope straight line on the log-log plot (Horne, 1995).

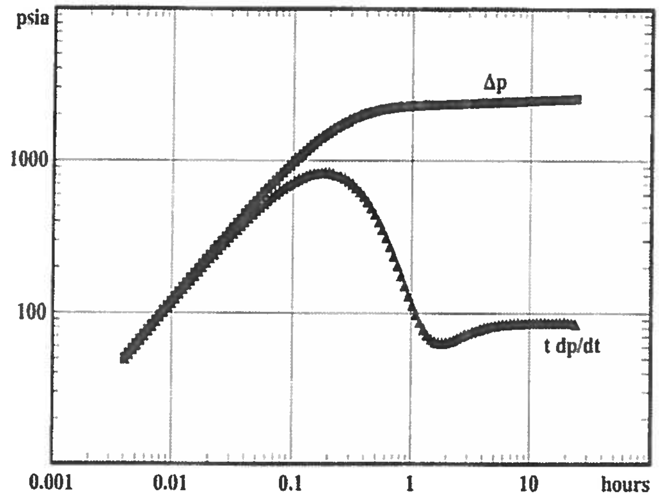

Figure 3.7: Illustration of a derivative plot (Horne, 1995).

Until a few decades ago, the plotted data and the type curves were compared by hand. The use of computers and software developed for well testing, such as Well Tester used in Iceland (introduced in Chapter 4), make the calculation of the derivative much easier, and this has become one of the major tools in well test analysis methods (Bourdarot, 1998; Gringarten, 2008).

3.6 Deconvolution

Deconvolution has received much attention recently (Von Schroeter et al., 2001; Levitan, 2005; Ilk et al., 2005; Levitan et al., 2006). Deconvolution is not a new interpretation but a new tool to process pressure and flow rate data (Gringarten, 2008). According to the general definition, the aim of deconvolution is to calculate the impulse response of the system, based on the pressure response and both constant and varying flow rates.

The data used for deconvolution are better from built up data than drawdown data, because of their good quality compared to drawdown data. The deconvolution does not assume a reservoir model but it assumes a mathematical model. It is a direct method using non-linear regression compared to the conventional methods used for well testing. Changing skin, changing wellbore storage, missing or incorrect initial pressure and gaps in the data can have a significant effect on the shape of the deconvolved type curves (Gringarten, 2008).

The steps for the deconvolution method can be described as follows:

- The partial derivative $t\frac{\partial p}{\partial t}$ is assumed,
- The starting point, P_i on the type curve is assumed,
- The derivative is then integrated to obtain the type curve,
- The type curve is superposed with flow rates,
- The calculated results are compared with the measured data,
- The total error is quantified,
- The derivative is modified and the procedure repeated until the minimum error in a least square sense is found.

The deconvolution method removes the restriction for a shut in, but does not remove the need for type curves. The final result of this identification method is an estimate of a type curve. This type curve can be used in order to estimate the reservoir properties. Different deconvolution methods and mathematical formulas can be found in Von Schroeter et al., 2001; Levitan, 2005; Ilk et al., 2005; Levitan et al., 2006.

4 Injection tests

4.1 Introduction

A common procedure in Iceland and elsewhere is to perform a step-rate injection test soon after the drilling and completion of the borehole. The injection tests consist of injecting cold water into the borehole and simultaneously recording downhole pressure and temperature (pressure and temperature profiles are analysed in Chapter 5). The injection test, opposite to the production test, causes an increase of the pressure in the well.

The twofold purpose of the injection test is to stimulate the well and to obtain data that can be analysed to calculate the transmissivity and storativity of the formation together with the skin (Bödvarsson et al., 1981; Axelsson et al., 2006).

Another characteristic of the borehole that is evaluated during injection test is the injectivity index *(II)*. The injectivity index predicts the performance of an injection well and is believed to reflect the success of the well meaning that the bigger its value, the better the reservoir permeability. It is defined by the ratio of the change of injection flow rate to the change in reservoir pressure measured in the borehole:

$$II = \frac{\Delta q}{\Delta p} \tag{4.1}$$

The numerical software Well Tester V.1.0.0 (Juliusson et al., 2008) is used for modelling and calculation of the reservoir parameters. Well Tester is a computer software that was developed at the Iceland GeoSurvey (ISOR) to handle data manipulation and analysis of well tests (mainly multi-step injection tests) in Icelandic geothermal fields. The process is divided into six simple steps (Juliusson et al., 2008):

- Parameters: The estimation of the reservoir temperature and pressure, the wellbore radius, the viscosity of the fluid, the porosity and the total compressibility are fed into the program in this step;
- Set steps: The number of injection steps are defined;
- Modify: This step is designed to clean, resample and correct the data for temperature variations within the wellbore during the course of the well test;
- Model: In this step, the most appropriate model for the reservoir being investigated is selected. To achieve this, the derivative plot is used, along with the pressure data on a log-log scale graph.
- Model all: This tab is designed to find the model parameters that give the best correspondence between a multi-step model and data set, modeling all the step together.
- Report: The program prepares a report of results at the end of the modeling.

In the following Section 4.2, Well Tester is used to estimate the transmissivity, the storativity and the injectivity indices for wells RN-17b, RN-18 and RN-23. Section 4.3 gives the summary of the results from Well Tester.

4.2 Well Tester modelling

4.2.1 RN-17b injection test

Well RN-17b is a directional well and it was drilled in 2008 to a measured depth, MD of 3077 m (True vertical depth, TVD is 2804 m). The injection test in RN-17b started just after completion of drilling in December 2008. A three-step injection test was performed the same day and the injection rates were from 20.1 L/s to 30.3 L/s; 30.3 L/s to 44.9 L/s and 44.9 L/s to 20.1 L/s, respectively. The total injection test was done in 9 hours with a pressure gauge being lowered to a depth of 2300 m.

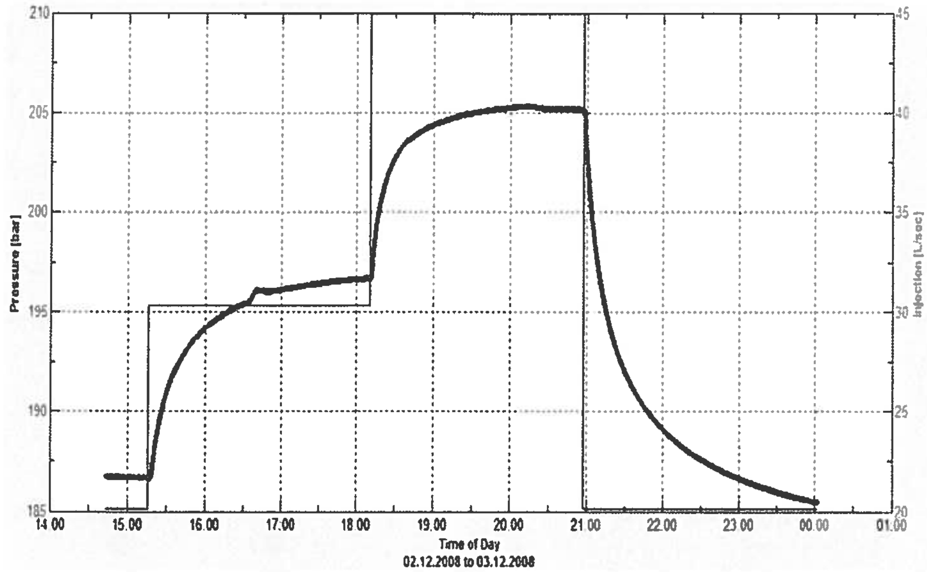

Figure 4.1: Pressure changes during step rate injection test for RN-17b.

Figure 4.1 shows the steps of the injection test and the pressure response for each step. A small hump on the pressure response for step 1 is observed, which could be an indication of an error from the tool during measurement. Step 2 shows a pressure drop towards the end of the step and this could indicate a small opening in the reservoir. The last step, step 3 indicates a falloff test and it can be observed that the pressure did not reach equilibrium at the end of the test. For this reason, it was decided to disregard this step in the modelling.

The well test model selected for RN-17b assumed a homogeneous reservoir, constant pressure boundary, constant skin and a wellbore storage. The pressure gauge depth was an input into the program and the data were cleaned. Using this model, a non-linear regression analysis was performed to find the parameters of the model that best fit the data. The best model was calculated by considering step 1 and 2, respectively and then, both steps together.

The results from the regression analysis for step 1 and step 2 are shown graphically in Figure A.1 and A.2. Figure 4.2 shows the best model calculated for RN-17b. The estimation of the parameters obtained on the basis of the steps and model selected for both step 1 and 2 (Table 4.1) indicate a permeability-thickness of 1 Dm, a storativity of $7 \cdot 10^{-8}$ $m^3/(Pa \cdot m^2)$ and an injectivity index of 1.3 (L/s)/bar. The values of the permeability-thickness and the injectivity index can be interpreted as a poor permeability in this part of the reservoir although the skin is negative.

Table 4.1: Summary of the results from non-linear regression parameter estimate using injection test data from well RN-17b

Step	Transmissivity ($m^3/(Pa \cdot s)$)	Storativity ($m^3/(Pa \cdot m^2)$)	Permeability thickness (Dm)	Skin	Injectivity index (L/s)/bar
1	$1.08 \cdot 10^{-8}$	$4.5 \cdot 10^{-8}$	0.9	-0.7	1.5
2	$1.4 \cdot 10^{-8}$	$3.03 \cdot 10^{-8}$	1.24	-0.9	1.7
1 and 2	$1.14 \cdot 10^{-8}$	$7.04 \cdot 10^{-8}$	1.02	-0.7	1.31

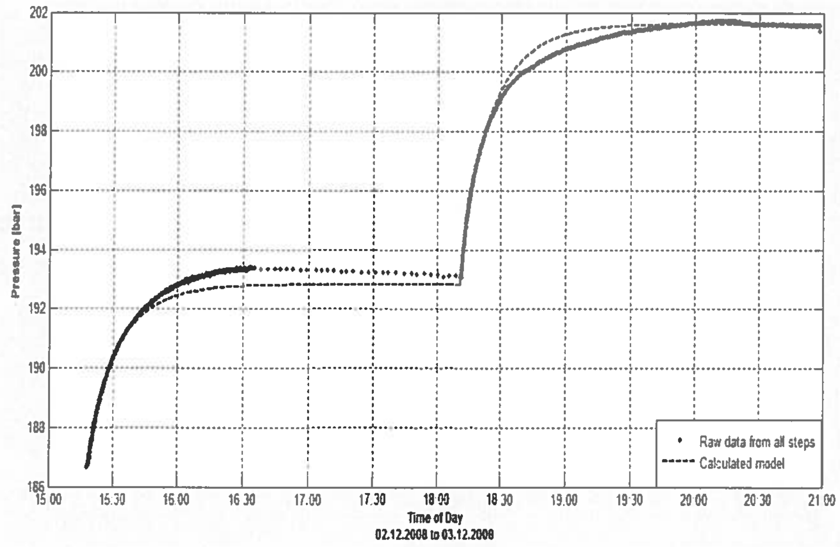

Figure 4.2: Fit between model and measured data for step 1 and 2 for well RN-17b

4.2.2 RN-18 injection test

Borehole RN-18 was drilled vertically to a depth of 1815 m and completed in January 2005. Two injection tests were performed afterwards with a pressure gauge being lowered to a depth of 1740 m. The two step injection rates were from 30.1 L/s to 48.2 L/s and 48.2 L/s to 25 L/s, respectively (Figure 4.3). The well test model selected for RN-18 assumed a dual porosity reservoir, constant pressure boundary, constant skin and a wellbore storage. The dual porosity behaviour is a pressure effect which is common in natural fractured reservoirs; it indicates the heterogeneity of the reservoir. This effect is noticeable in pressure transients in reservoir that have distinct and secondary porosity. The dual porosity effect is shown as a minimum on a derivative plot (Horne, 1995). The pressure gauge depth was an input into the program and the data were cleaned. The best model was calculated by considering step 1 and step 2, respectively and then, both steps together.

Using this reservoir model and after calculations, the best fit indicate a permeability-thickness of 3.5 Dm, a storativity of $5 \cdot 10^{-8}$ $m^3/Pa \cdot m^2$ and an injectivity index of

4.3 (L/s)/bar with a negative skin (Figure 4.4 and Table 4.2). The results from the regression analysis for step 1 and step 2 are shown graphically in Figure A.3 and A.4.

The permeability-thickness and the injectivity index for RN-18 is higher than the one calculated for RN-17b showing a better permeability in this part of the reservoir. This could mean that either RN-18 intersects more permeable features than RN-17b or that it is drilled into a steam cap.

Table 4.2: Summary of the results from non-linear regression parameter estimate using injection test data from well RN-18.

Step	Transmissivity ($m^3/(Pa\cdot s)$)	Storativity ($m^3/(Pa\cdot m^2)$)	Permeability Thickness (Dm)	Skin	Injectivity index (L/s)/bar
1	$2.5\cdot10^{-8}$	$4.9\cdot10^{-8}$	2.2	-2.6	4.6
2	$1.5\cdot10^{-8}$	$2.8\cdot10^{-8}$	1.3	-3.7	4.5
1 and 2	$3.4\cdot10^{-8}$	$4.7\cdot10^{-8}$	3.5	-0.85	4.3

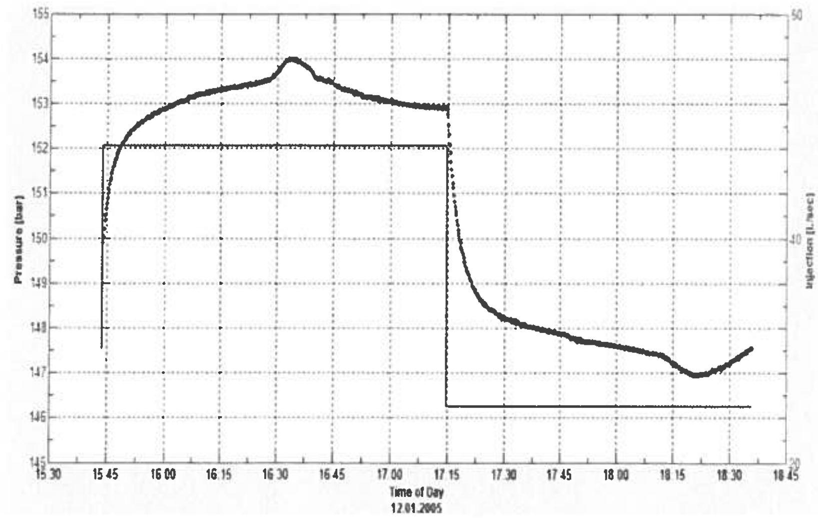

Figure 4.3: Pressure changes during step rate injection test for RN-18.

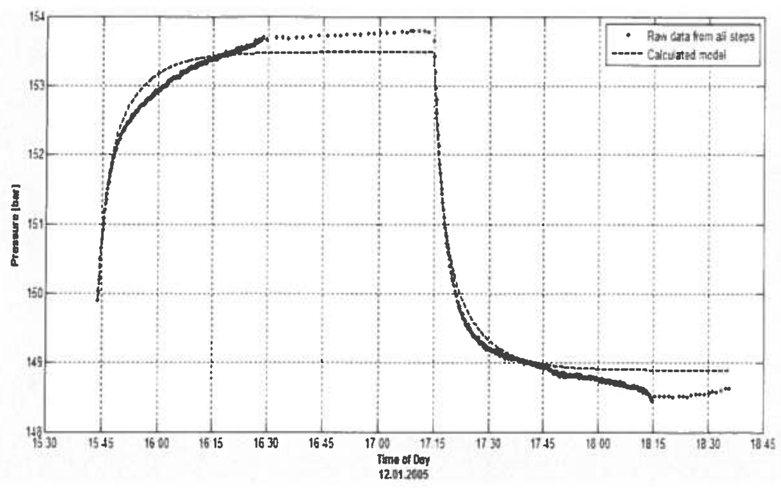

Figure 4.4: Fit between model and measured data for step 1 and 2 for well RN-18.

4.2.3 RN-23 injection test

RN-23 is a directional well that was drilled in early 2006 and completed in late March at a depth of 1924 m. A three step rate injection test was performed after drilling with a pressure gauge being lowered to a depth of 1330 m. The three step injection rates were from 65 L/s to 30 L/s; 30 L/s to 45 L/s and 45 L/s to 60 L/s, respectively The well test model selected for RN-23 assumed a dual porosity reservoir, infinite boundary, constant skin and a wellbore storage.

Figure 4.5 shows the steps of the injection test and the pressure response for each step. It can be observed that data are missing in the pressure response for step 1. For this reason, this step was not considered in the modelling. Therefore, the best model was calculated by considering only pressure build-up for step 2 and 3, respectively and then, both steps together. The pressure gauge depth was an input and the data were cleaned. The results from the regression analysis for the individual steps (step 2 and step 3) are shown graphically in Figure A.5 and A.6.

Figure 4.6 shows the best match calculated for RN-23 for both step 2 and step 3. The results in Table 4.3 show a permeability-thickness of 29 Dm, a storativity of $2\cdot10^{-7}$ $m^3/Pa\cdot m^2$ and an injection index of 36 (L/s)/bar.

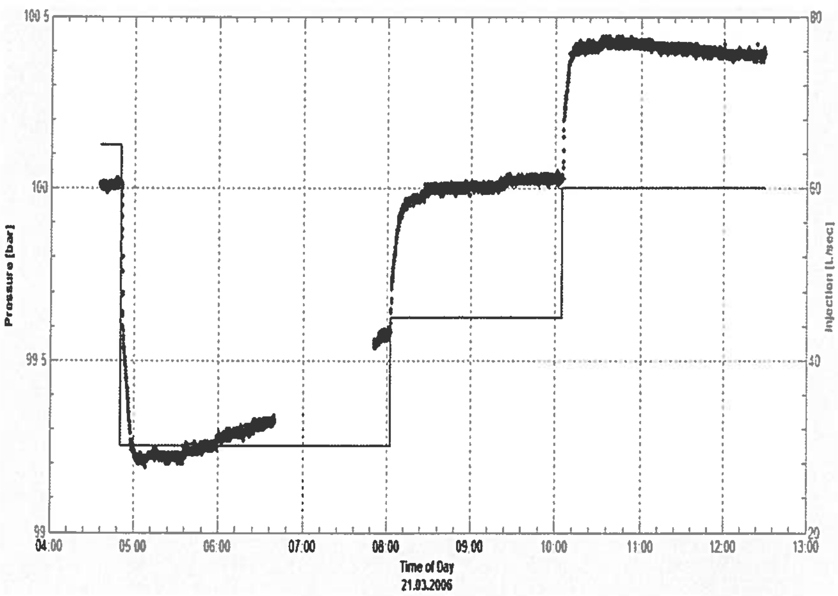

Figure 4.5: Pressure changes for step-rate injection test for RN-23.

Table 4.3: Summary of the results from non-linear regression parameter estimate using injection test data from well RN-23.

Step	Transmissivity ($m^3/(Pa\cdot s)$)	Storativity ($m^3/(Pa\cdot m^2)$)	Permeability Thickness (Dm)	Skin	Injectivity index (L/s)/bar
2	$1.4\cdot10^{-7}$	$1.14\cdot10^{-7}$	12.4	-4.3	33.2
3	$4.6\cdot10^{-7}$	$8.3\cdot10^{-7}$	40.6	-1.02	39.9
2 and 3	$3.3\cdot10^{-7}$	$1.7\cdot10^{-7}$	28.9	-2.5	36.2

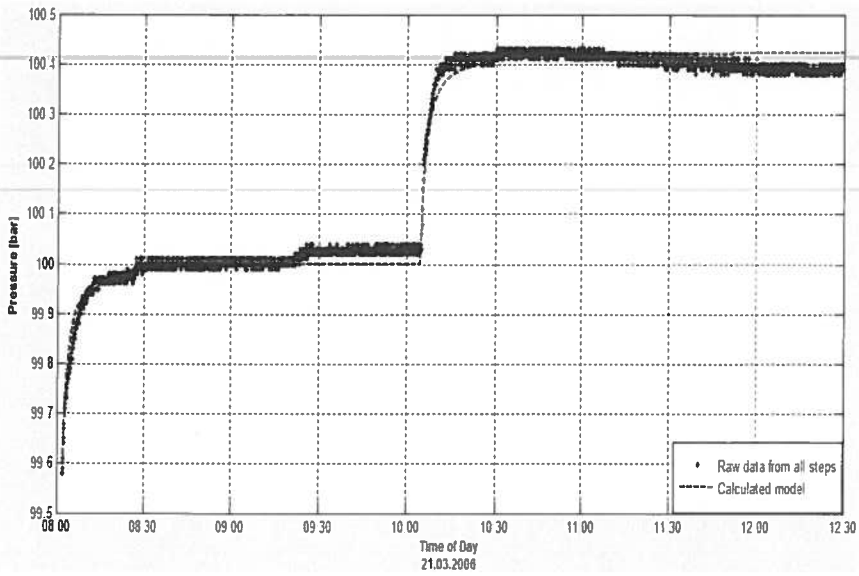

Figure 4.6: Fit between model and measured data for step 2 and 3 for well RN-23.

The permeability-thickness and the injectivity index values for RN-23 are higher than for the other two wells, RN-17b and RN-18. The explanation of the results found here could be that well RN-23 is intersecting more permeable features or that, the well is intersecting a steam cap in this part of the reservoir. The good permeability is also confirmed by the high value of the negative skin. The storativity value is high meaning that RN-23 intersects a steam cap.

4.3 Summary

The results in Table 4.4 give a summary of different transmissivity, storativity and permeability values for RN-17b, RN-18 and RN-23, respectively. To calculate the permeability, a constant reservoir thickness of 2000 m was assumed.

Table 4.4: Summary of the results for wells RN-17b, RN-18 and RN-23.

Well	Transmissivity (m^3/Pa·s)	Storativity (m^3/Pa· m^2)	Permeability Thickness (Dm)	Permeability (mD)	Skin	Injectivity index (L/s)/bar
RN-17b	$1.14\cdot10^{-8}$	$4.5\cdot10^{-8}$	0.9	0.5	-0.7	1.3
RN-18	$3.4\cdot10^{-8}$	$4.7\cdot10^{-8}$	4.1	2.1	-0.8	4.3
RN-23	$3.3\cdot10^{-7}$	$1.7\cdot10^{-7}$	28.9	14.5	-2.5	36.2

The results indicate that RN-23 has the highest transmissivity, while RN-17b has the lowest transmissivity. The transmissivity of RN-23 is one order of magnitude higher than for RN-18 and RN-17b. The permeability values show high permeability in RN-23. Considering that well RN-23 is not far away from well RN-18, the high value of the permeability could be that well RN-23 is drilled into a steam cap (relative permeabilities are considered) and/or that it intersects more permeable fractures than RN-18. The poor permeability of RN-17b in this part of the reservoir could be explained as a thermal expansion of the reservoir rocks due to the high temperature measured in this well (see sub section 5.2.2) increasing the number of closed voids in the rock matrix (Björnsson and Bödvarsson, 1990). The poor permeability of RN-17b can also simply mean that the well does not intersect as many fractures or that the reservoir is less permeable at the outskirts than in the central part of the geothermal field.

The storativity values for the three wells are of the same order of magnitude for RN-17b and RN-18 and one order of magnitude higher for RN-23. The high storativity value for RN-23 could be as stated above because the well is drilled into a steam cap. The skin factors for the injection test of wells RN-17b, RN-18 and RN-23 are estimated -0.7, -0.8 and -2.5, respectively. This indicates stimulated wells and/or fractured zone in the reservoir.

The injectivity index is used as a rough estimate of the connectivity between the well and the surrounding reservoir. The results show an injectivity index which is one order of magnitude higher for RN-23 as compared to RN-18 and RN-17b. The values of the injectivity indices for RN-23 and RN-18 are compared with the productivity indices for the same wells in Chapter 6.

5 Analyses of pressure and temperature profiles

5.1 Introduction

The downhole profiles of temperature and pressure with depth are a valuable tool in gaining information on the physical conditions of the reservoir and well performance. In geophysics the term "log" indicates continuous measurement of a parameter with time or, in space carried out in boreholes (Stefánsson and Steingrímsson, 1990). The basic measurements made in geothermal wells are pressure and temperature logs or profiles. The logs are normally measured over the full depth of the wellbore. The well may be shut in, flowing or under injection (Grant and Bixley, 2011).

The purpose of analysing downhole data is therefore to deduce from the logging made within the dynamic fluid inside the wellbore the properties of the reservoir around the well. However, caution must be taken when interpreting logs as measurements are not made directly in the reservoir but in the well where internal flows and boiling can cause disturbances and give misleading results even though the well is shut in (Stefánsson and Steingrímsson, 1990).

Analyses of temperature and pressure profiles during warm up leads to an estimation of the formation temperature and the initial reservoir pressure as well as the location of the feed zones. Temperature measurements during fluid injection or production can indicate the feed or loss zones under the test conditions. The feed zones or permeable zones are the regions where hot and cold water flows in and out of a well and usually show up as temperature anomalies, either hot or cold.

In this study, the formation temperature is estimated by using an analytical method, the Horner method (Dowdle and Cobb, 1975) through the BERGHITI program (Helgason, 1993) from the ICEBOX software package (Arason et al., 2004). The Horner method is an analysis method based on the straight line relationship between the wellbore temperature, T and the logarithm of relative time, τ called the Horner time, where $\tau = \frac{t_0+\Delta t}{\Delta t}$ and t_o is the circulation time that is the time that the well has been cooled by the drilling fluid, and Δt is the time since the circulation of drilling fluid was stopped. The measured wellbore temperature at a given depth from several temperature logs is plotted against log (τ). This plot is a straight line that intersects the vertical line $\tau = 1$, corresponding to $\Delta t \rightarrow \infty$, at the formation temperature.

The boiling point curve was considered when estimating the formation temperature to determine if there is boiling in the borehole and at which depth. The boiling point curve for an individual borehole was calculated assuming initial water level and the program BOILCURV from ICEBOX was used for this purpose.

The initial pressure condition of the wells is estimated by feeding the evaluated formation temperature into the program PREDYP (Björnsson, 1993), from the ICEBOX package. The program computes pressure in a static fluid column with known temperature. The water level (or wellhead pressure) is required for the calculation and is adjusted until the calculated profile matches the measured pressure at the pivot point. The pivot point shows the depth to and pressure at the best feed zone in the borehole and can be considered as the actual pressure value in the reservoir.

In the following sections (5.2 to 5.3), the temperature and pressure profiles are analysed to locate the feed zones, pivot points and estimate the initial reservoir pressure and the formation temperatures for the Reykjanes wells RN-12, RN-17B, RN-18, RN-23 and RN-29. The temperature and pressure measurements in these wells were performed during injection, warm up and flowing of the wells.

5.2 Temperature and pressure analyses

In this section, the temperature and pressure profiles for wells RN-12, RN-17B, RN-18, RN-23 and RN-29 are interpreted to identify the main feed zones and locate the pivot point of each well where possible.

5.2.1 RN-12

Borehole RN-12 was drilled in 2002 to a depth of 2506 m. No liner was put in the hole. The casing design is as follows:

Hole diameter	Hole depth (m)	Casing size	Casing depth (m)
21"	293	18 5/8"	291
17 ½"	845	13 3/8"	842
12 ¼"	2506	no liner	

Figure A.7 shows the temperature and pressure profiles for well RN-12 after drilling with and without injection, during warm up and during flowing of the well. The injection temperature profiles show three main feed zones. One located around 1000 m and the second at 1300 m showing fluid inflow identified as steps in the profile. Another feed zone is observed around 2200 m representing an outflow which is indicated by a change in the temperature gradient. Temperature profiles during warm up show the same pattern and indicate feed zones at 1000 m, 1300 m and around 2200–2300 m. Below 1000 m depth, cross flow between the two feed zones from 1300 m to 2200 m is observed characterized by a fairly constant temperature and consequently vertical connection between these levels. From September 2003 to October 2004, the temperature was 279 °C from 1300 m to 2200 m depth and it increased in the last logs to 298–299 °C from 1500 m to 2200 m depth. At the feed zone at around 2200–2300 m, a small temperature inversion was observed, lowering the temperature to 279 °C and after complete recovering this temperature increased to 290 °C. The well has a maximum recorded temperature of 310 °C at the well bottom. The temperatures from 2007 to 2011 indicate a constant profile indicating that the well has reached the formation temperature.

Pressure profiles during warm up show a pivot point at around 1300 m with a pressure of 106 bar-g. The pivot point indicates the pressure control point and is represented as a single point at which the pressure in the well is the same as the reservoir pressure because of the connection of the well to the reservoir. It should be emphasised that for a single feed zone well, the feed zone and the pivot point should be at the same depth. However, for multiple feed zones, the pivot point will be between the top and bottom feed zone and its exact location will depend on the permeability of the feed zones (Stefánsson and Steingrímsson, 1990; Grant and Bixley, 2011). A drawdown, meaning a decrease of pressure, at the well bottom of about 8 bar is observed from 2007 to 2008 but from 2008 to 2011, the drawdown has been almost constant varying between 1 bar and 2 bar per year. Pressure profiles during discharge indicate a flashing level (boiling in the well) at about 1000 m depth.

5.2.2 RN-17b

This well is a directional well and it was drilled in 2008 to a measured depth of 3077 m. The casing design for well RN-17b is as follows:

Hole diameter	Hole depth (m)	Casing size	Casing depth (m)
21"	352	18 5/8"	340
17 ½"	901	13 3/8"	892
12 ¼"	3077	9 5/8" liner	3075

Figure A.8 shows the temperature and pressure profiles for well RN-17b during injection, warm up and discharge testing. The profiles were plotted versus MD. The temperature profiles during injection show two main feed zones at around 1250-1300 m and around 1750-1800 m. Temperature profiles during warm up indicate similar feed zones at 1250 m and around 1750-1800 m. In 2009, the bottomhole temperature recovered in two months from 299 °C to 330 °C. The highest temperature measured in RN-17b is 348 °C at the bottom. The temperature profiles suggest a heat transfer by conduction from the reservoir to the well.

Pressure profiles show pressure instability in the well. In 2009, the wellhead pressure rose from 5.5 bar-g to 43 bar-g in five months and suddenly dropped again to 5.8 bar-g when the well was opened to flow in the same month. The last flowing test in November 2010 indicates a wellhead pressure of 45 bar-g and a bottomhole pressure of 182 bar-g. The previous test in March the same year indicates a wellhead pressure of 6 bar-g and bottomhole pressure of 152 bar-g. The pressure profiles indicate no pivot point indicating that there is a bad connection between the well and the reservoir. The pressure instability in RN-17b and the difficulty to determine a pivot point indicate the poor permeability of the reservoir in the area of drilling. Pressure profiles during warm up indicate a water level in the well at around 350 m depth.

5.2.3 RN-18

This borehole was drilled vertically and completed in January 2005 at a depth of 1815 m. The casing design is described as follows:

Hole diameter	Hole depth (m)	Casing size	Casing depth (m)
21”	351	18 5/8”	349
17 ½”	750	13 3/8”	749
12 ¼”	1815	9 5/8” liner	1799

Figure A.9 shows the temperature and pressure profiles for well RN-18 during injection, warm up and discharge testing. The temperature profiles during injection show a feed zone just under the production casing shoe at around 800 m depth. The temperature profiles from 2006 indicate similarly a feed zone at 800 m and small feed zones at 1100 m and 1300 m depth, respectively. From 1100 m to 1300 m depth, the temperature is isothermal varying from 278 °C to 280 °C, respectively, suggesting down flowing fluids indicating vertical movement of fluid. In 2008, the temperature profiles show a slight increase in temperature to 285 °C at 1400 m depth. The temperatures from 2007 to 2011 indicate a constant profile from 1500 m down to the bottom showing that the well has reached the formation temperature.

There were not enough warm up pressure profiles to determine the pivot point. A drawdown of 6 bars is observed for the years 2007 to 2008 and of 4 bars for the years 2008 to 2011 indicating a progressive stabilisation of the well bottom pressure. The last pressure profiles during discharge indicate a flashing level close to 950 m depth.

5.2.4 RN-23

RN-23 is a directional well and was drilled in early 2006 to a measured depth of 1924 m. The true vertical depth (TVD) is 1742 m. The casing design for well RN-23 is as follows:

Hole diameter	Hole depth (m)	Casing size	Casing depth (m)
21”	296	18 5/8”	295
17 ½”	702	13 3/8”	701
12 ¼”	1924	9 5/8” liner	1923

Figure A.10 shows the temperature and pressure profiles of well RN-23 during injection, warm up and discharge testing. The temperature and pressure profiles were plotted versus the measured depth. Feed zones at around 950 to 1000 m, 1100 m and 1350 to 1400 m can be identified from the temperature profiles. The profile shows boiling during flowing of the well at around 1150 m depth. Cross flow characterized by a fairly constant temperature of 310 °C between the two feed zones at 1100 m and 1350 m is evident suggesting a vertical fluid flow between those two feed zones. The temperature profiles from 2007 to 2011 indicate a stable profile meaning that the well has probably reached the formation temperature.

There were not enough warm up pressure profiles to determine the pivot point. The pressure profiles show a drawdown of about 10 bar from 2006 to 2008 and 5 bar from 2008 to 2011 indicating a progressive stabilisation of the well bottom pressure. The pressure profiles indicate a flashing level at around 1150 m depth.

5.2.5 RN-29

The casing design for well RN-29 is as follows:

Hole diameter	Hole depth (m)	Casing size	Casing depth (m)
21"	306	18 5/8"	305
17 ½"	902	13 3/8"	901
12 ¼"	2837	9 5/8" liner	2500

This borehole is vertical and was drilled in 2010 to a depth of 2837 m. Figure A.11 shows the temperature and pressure profiles of well RN-29 during injection, warm up and discharge testing. The temperature profiles during injection show the main feed zone at 2150 m depth. Small feed zones can be observed at 1100 m, 1750 m and 2500 m depth. Temperature profiles during warm up indicate a water level at around 300 m depth and reveal a temperature inversion to a minimum of 230 °C from 1800 m to 2500 m depth which could be an indication that the outer boundary of the system has been reached. Feed zones are observed during warm up at around 1200 m, 1600 m, 1850 m and 2500 m depth. RN-29 has a maximum recorded temperature of about 320 °C at the well bottom.

Pressure profiles show a pivot point between 1750 m and 1800 m with 131 bar-g pressure. The last logs performed in January 2011 were done down to a depth of 1200 m and could not be interpreted. The pressure profile from November 2010 during discharge, indicate a flashing level at a depth of about 2200 m.

5.3 Reservoir temperature and pressure

In this section the formation temperature and the initial reservoir pressure for the Reykjanes wells RN-12, RN-17b, RN-18, RN-23 and RN-29 are estimated (Figure A.7 to

A.11) from the analyses of Section 5.2. The reservoir temperature and initial pressure for each well are represented in Figure 5.1 and 5.2, respectively. The temperature profiles during warm up and flowing were considered for individual wells to estimate their formation temperature.

The formation temperature for well RN-12 (Figure A.7) suggests pure gradient in the top 400 m. The formation temperature profile follows the boiling point curve in the zone from 500 m to 1000 m depth indicating supersaturated or steam dominated conditions in the well and reservoir at this level. Below 1000 m depth, the formation temperature profile is below the boiling point curve indicating a liquid dominated reservoir at this depth. A slight temperature inversion is observed at around 2000-2200 m depth. The reservoir temperature for RN-12 is estimated around 300 °C with a maximum of 310 °C at the bottom.

The formation temperature for RN-17b in Figure A.8 suggests that there is no boiling in the well. The reservoir temperature is estimated to be around 340 °C at the bottom of the well.

The formation temperature for RN-18 in Figure A.9 suggests a temperature corresponding to the boiling point curve of water at around 400-900 m depth. Below 900 m depth, the formation temperature profile is below the boiling point curve indicating a liquid dominated reservoir from this depth and downwards. The profile is vertical to the bottom of the well indicating a vertical flow. The reservoir temperature is estimated to be around 284 °C.

The formation temperature for RN-23 in Figure A.10 suggests a temperature corresponding to the boiling point curve of water from 500 m down to 1100 m depth. The reservoir temperature is estimated to be around 302 °C. Below 1100 m depth, the formation temperature profile is below the boiling point curve and constant indicating a vertical flow.

The formation temperature for RN-29 in Figure A.11 shows conduction in the casing and a possible temperature inversion at 1800-2500 m depth. The formation temperature at the bottom is estimated to be around 320 °C.

The initial reservoir pressure down to 1000 m depth is high for RN-12 and low for RN-17b. Below 1000 m depth, the initial reservoir pressure is high for RN-23 and low for RN-17b. Between 1400 and 1550 m depth, the pressure for RN-12 and RN-23 are the same.

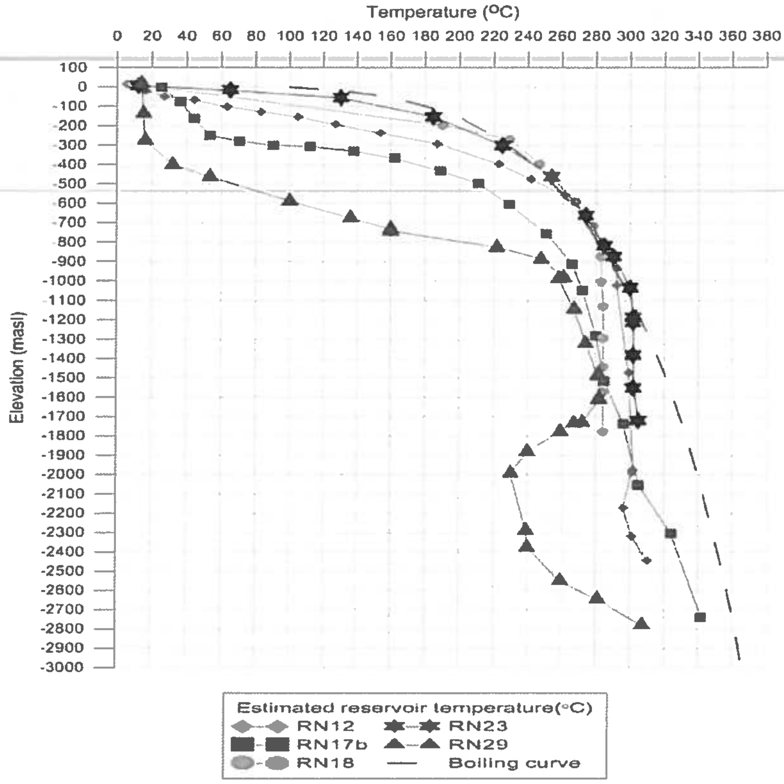

Figure 5.1: Estimation of the formation temperature for wells RN-12, RN-17b, RN-18 and RN-29.

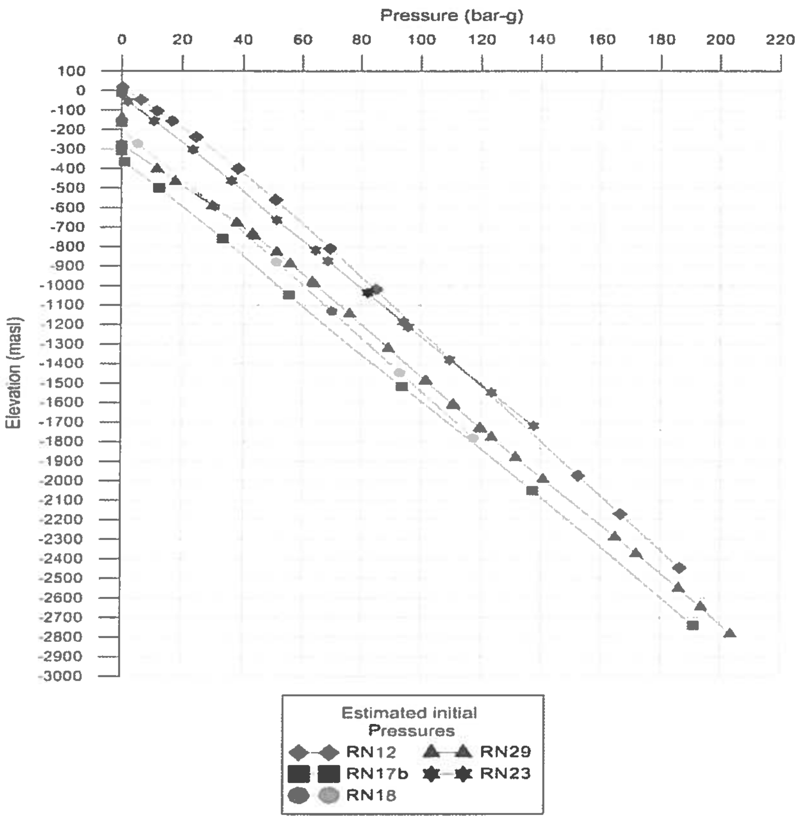

Figure 5.2: Estimation of the initial pressures for wells RN-12, RN-17b, RN-18 and RN-29.

6 Discharge tests

6.1 Introduction

After a long warm up period (often for several months), the fluid temperature in the well increases. Eventually there is a build up of a wellhead pressure above the atmospheric pressure if the well is artesian, meaning that pressurised fluid naturally rises to the surface when the well is open to flow. The well can then be discharged through an orifice to estimate the production capacity of the well. In case the well does not spontaneously discharge, different methods are used to start off the discharge. More information about these methods can be found in Grant and Bixley (2011).

During the production test, the fluid flow (total flow rate), its energy content (enthalpy) and chemical characteristics are measured. The pressure (and temperature) logger are usually placed at the bottom of the hole for pressure (and temperature) measurements. The lip pressure method (James, 1966) or the separator method can be used to determine the flow characteristics with a simple weir being used to measure the liquid flow. Where environmental conditions permit, a brief vertical discharge directly to the atmosphere can be used with the lip pressure method to get the first estimate of the longer-term production potential. In this case the fluid enthalpy can be estimated by observation of the discharge plume and downhole conditions at the feed zone prior to discharge (Grant and Bixley, 2011). The well productivity as a function of wellhead pressure can be determined by repeating the flow test with different size orifices or by a step-rate test. The pressure and temperature logs together with information from the discharge tests can also be simulated to estimate the productivity indices of the wells. The wellbore simulator HOLA (Björnsson et al., 1993) is used for this purpose as discussed in Section 6.4.

The lip pressure method, the separator method and the HOLA wellbore simulator are described in the following Sections (6.2 to 6.4) and used to calculate the flow characteristics and productivity indices for three wells; RN-13b, RN-18 and RN-23. Injectivity and productivity indices are then compared in Section 6.5.

6.2 Lip pressure testing

This method is based on an empirical formula developed by James (1966). The James lip pressure method is the most flexible and economical method for flow testing. This method consists of discharging the steam-water mixture produced by a test well through an appropriately sized pipe into a silencer or some other device for separating the steam and water phase at atmospheric pressure (Figure 6.1). Sometimes the orifice pipe simply opens to the atmosphere. The lip pressure or critical pressure, which is the pressure at which the flow changes from subcritical to supercritical flow. This pressure is measured at the extreme end of the discharge pipeline as it enters the separator. The separated water flow rate exiting from the separator is measured using a sharp-edged weir near the silencer outlet while the steam is discharged to the atmosphere (Grant and Bixley, 2011).

The James formula is represented as follows:

$$\frac{Q_t H_t^{1.102}}{A P_c^{0.96}} = 184 \tag{6.1}$$

Where Q_t is the total mass flow rate in kg/s, H_t is the total enthalpy in kJ/kg, A is the cross-sectional area of the lip pipe in cm^2, and P_c is the lip pressure in bar-a (absolute).

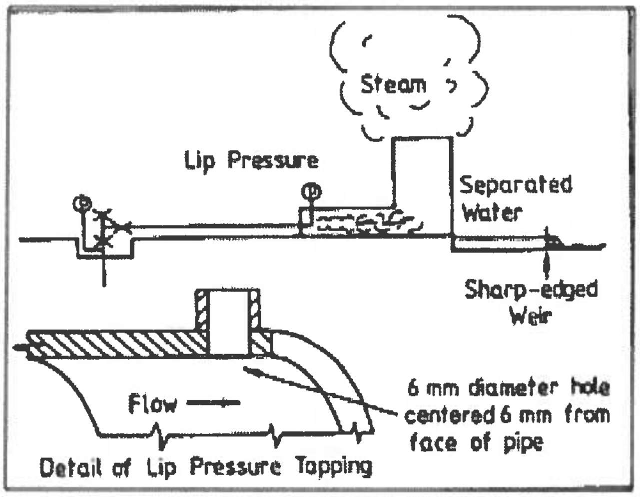

Figure 6.1: Flow measurement using the lip pressure method (Grant et al., 1982)

For the discharged fluid that is separated at atmospheric pressure, the enthalpies of the two phases, steam and water, H_s (kJ/kg) and H_w (kJ/kg), are used in the formula together with the total enthalpy of the well fluid. Knowing the separated water flow rate Q_w (kg/s), the total flow rate is given by:

$$Q_t = Q_w \frac{H_s - H_w}{H_s - H_t} \tag{6.2}$$

Since the well is discharged at atmospheric pressure, the specific enthalpies of steam and water at atmospheric pressure should be used and equation (6.2) can be rewritten as follows:

$$Q_t = Q_w \frac{2256}{2676 - H_t} \tag{6.3}$$

The enthalpy H_t can then be determined by combining equation (6.1) and (6.3)

$$184\, A \frac{P_c^{0.96}}{H_t^{1.102}} = Q_w \frac{2256}{2676 - H_t} \tag{6.4}$$

By measuring the lip pressure, the water flow rate and knowing the cross sectional area of the orifice, the total enthalpy can be calculated numerically.

RN-13b, a directional well that was drilled down to a measured depth of 2530 m and a true vertical depth of 2200 m. RN-13b and RN-18 were discharged on October 11, 2007 and August 11, 2005, respectively, through a lip pressure pipe of 16 cm in diameter into a silencer that also acts as a steam/water separator at atmospheric pressure. The flow of the liquid phase was measured using a V-notch weir box. RN-23 was discharged on May 23, 2006 directly to the atmosphere through a vertical discharge pipe of 21.2 cm in diameter. There was no measurement of the water flow rate and no separator. The measurements for the wells were done in five steps, four steps and six steps for RN-13b, RN-18 and RN-23, respectively. Table 6.1 shows the average of the measurements and the calculated values for the parameters during the flow test of well RN-13b, RN-18 and RN-23. Enthalpy and mass flow rate parameters for RN-13b and RN-18 were calculated using the LIP program from ICEBOX. The LIP program requires the input of the pipe diameter, the lip pressure and the water height in the weir to calculate the flowing mass and enthalpy. The same parameters for RN-23 were calculated directly from equation 6.1 using an estimated total enthalpy from the temperature and pressure profiles. The enthalpy at the wellhead for RN-23 was considered to be the same as the enthalpy at the bottom of the well and could be estimated knowing the downhole pressure and temperature.

The productivity index was calculated by dividing the change in flow rate by the change in pressure at each step for individual wells. The average productivity indices for well RN-13b, RN-18 and RN-23, respectively are given in Table 6.1.

Table 6.1: Calculated flow characteristics for RN-13b, RN-18 and RN-23 using the lip pressure method

Well	WHP (bar-g)	Lip Press (bar-g)	Enthalpy H (kJ/kg)	Q_t (kg/s)	Q_w (kg/s)	Q_s (kg/s)	PI (kg/s)/bar
RN-13b	41	2.5	1570	33	16	17	3.4
RN-18	32	3	1420	41	23	18	1.4
RN-23	46	2.7	1406	56			66

6.3 Steam-water separator testing

The separator method (Figure 6.2) is the most accurate method for measuring two-phase flow from geothermal wells (Bangma, 1961). The water flow rate is measured using a sharp-edged weir after flashing to atmospheric pressure and the steam flow rate is measured at separator pressure (Grant and Bixley, 2011).

The general equation for the separated steam flow rate is given by:

$$Q_s = C \cdot \varepsilon \cdot \sqrt{\frac{\Delta P}{v_{fluid}}} \tag{6.5}$$

where C is an orifice constant, which depends on the pipe and orifice geometry and pressure tapping geometry; ε is the expansibility factor for compressible gases; ΔP the differential pressure across the orifice in millibar (mbar) and v_{fluid} is the specific volume of the fluid passing through the orifice in cm^3/gm (Grant and Bixley, 2011).

The water flow rate, Q_w can also be calculated from the water height W in the weir box by the following formula:

$$Q_w = C \cdot (W - W_o)^b \tag{6.6}$$

where, C, W_o and b are constants (Linford, 1961). C depends on the geometry of the weir and the friction between the fluid and the weir sides. W_o is the water level at which the water flow rate is zero. The constant, b describes the geometry of the weir.

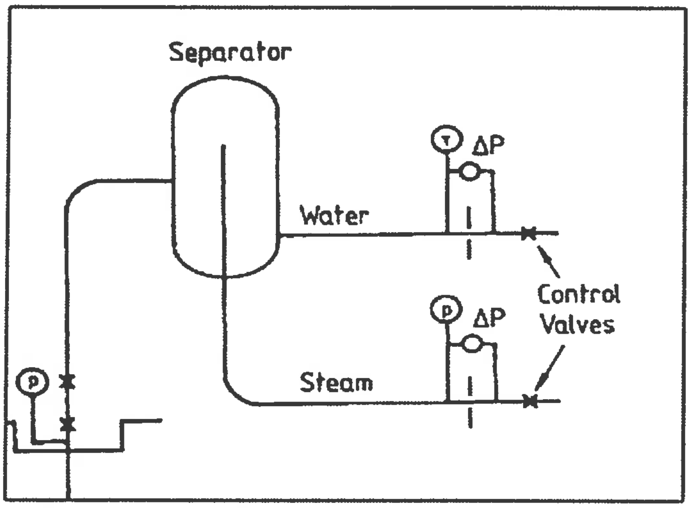

Figure 6.2: Separator used in well testing (Grant et al., 1982)

For the Reykjanes geothermal field, the separator is calibrated and the following equations are used for the calculations:

$$Q_s = 2.733 \cdot \sqrt{\Delta \mathrm{P}} \tag{6.7}$$

$$Q_w = 0.0146W^{2.47} \tag{6.8}$$

Where, the flow rates Q_s and Q_w are measured in kg/s, ΔP in mbar and W in cm.

The steam and water flow rate parameters for RN-13b and RN-18 were calculated using equations (6.7) and (6.8) and the enthalpy was calculated, using the following equation:

$$H = XH_s + (1 - X)H_w \tag{6.9}$$

where X is the mass ratio of steam, Q_s/Q_t, and H_s and H_w are the specific enthalpies of steam and water, respectively, at atmospheric pressure. Table 6.2 shows the measured and calculated parameters during the flow tests of wells RN-13b and RN-18.

The steam and water flow rates for RN-23 could not be estimated since the well was discharged directly to the atmosphere.

Table 6.2: Calculated flow characteristics for RN-13b and RN-18 using the separator method

Well	WHP (bar-g)	Lip Press (bar-g)	Enthalpy H (kJ/kg)	Q_t (kg/s)	Q_w (kg/s)	Q_s (kg/s)
RN-13b	41	3	1580	33	16	17
RN-18	32	3	1338	39	23	16

The calculated parameters from the two methods show some similarities. By assuming that the conversion rate is 2 kg/s of steam per Megawatt electric, MW_e (Grant et al., 1982), the power generation for wells RN-13b and RN-18 is about 8.5 MW_e and between 8 MW_e and 9 MW_e, respectively.

6.4 Simulation of wellbore flow

6.4.1 Theory

The wellbore simulator HOLA (the Icelandic word for "well") reproduces the measured pressure and temperature profiles in a flowing well and determines the thermodynamic properties of the water, relative flow rates at each feed zone for a given discharge condition at the wellhead. The simulator can handle both single and two-phases flow in vertical pipes (Björnsson et al., 1993).

HOLA has two approaches (mode 1 and mode 2) for wellbore flow simulation that are mostly used out of the six modes offered by the simulator. For the first approach (mode 1), one needs to know the discharge condition at the wellhead (pressure, temperature and enthalpy), in addition to flow rates and enthalpies of all but the last feed zone. The simulator proceeds from the wellhead to the bottom of the hole, calculating the flowing temperature and pressure profiles down the well. In mode 2, the user specifies the required flowing wellhead pressure and the bottomhole pressure. For each feed zone, the productivity index, the thermodynamic properties of the reservoir fluid and the wellbore geometry must be known. The simulator then proceeds from bottomhole to wellhead to calculate the expected wellhead output (wellhead enthalpy, flow rate, temperature and phase composition) for the required wellhead pressure.

The simulator solves numerically the differential equations that describe the steady state mass, momentum and energy flow in a vertical pipeline as follows (Björnsson, 1987; Björnsson et al, 1993):

Mass balance

$$\frac{dQ_t}{dz} = 0 \tag{6.10}$$

Momentum balance

$$\frac{dP}{dz} - \left[\left(\frac{dP}{dz}\right)_{fri} + \left(\frac{dP}{dz}\right)_{acc} + \left(\frac{dP}{dz}\right)_{pot}\right] = 0 \tag{6.11}$$

Energy balance

$$\frac{dE_t}{dz} \pm Q = 0 \tag{6.12}$$

Where Q_t is the total mass flow rate in kg/s, P the pressure in Pascal (Pa), E_t the total energy flux in the well in J/s and z is the depth coordinate in m. Q denotes the ambient heat loss over a unit distance in W/m. The plus and minus sign indicates downflow and upflow, respectively. The pressure gradient $\frac{dP}{dz}$ is composed of three terms: wall friction, acceleration of fluid and change in gravitational load over the depth interval, *dz*.

The governing equation of mass flow rate between the well and the reservoir, through a given feed-zone is given by:

$$Q_{feed} = PI\left[\frac{k_{rw}\rho_w}{\mu_w} + \frac{k_{rs}\rho_s}{\mu_s}\right](P_r - P_w) \tag{6.13}$$

where Q_{feed} is the feed zone flow rate in kg/s , PI is the productivity index of the feed zone in m^3, k_r is the relative permeability for water and steam, μ is the viscosity in Pa·s, ρ is the density in kg/m^3, P_r is the reservoir pressure and P_w is the pressure in the well in bar-a. The subscripts, *s* and *w* refer to steam and water, respectively.

The program calculates the productivity index at one feed zone by the following equation:

$$PI = \left(\frac{q_\beta}{P_\beta - P_{wb}}\right)\left(\frac{\mu_\beta}{k_{r\beta}\rho_\beta}\right) \tag{6.14}$$

where the subscript β indicates the feed zone phase, liquid or steam.

The relative permeabilities are calculated by a linear relationship: $k_{rs}= S$ and $k_{rw}= 1-S$, where S is the volumetric steam saturation of the reservoir. μ and ρ are calculated knowing the temperature at feed zone β (Björnsson, 1987).

In general, wellbore simulators are very sensitive to the phase velocity relations used. They can only be obtained through empirical correlations. The formula for two-phase flow calculations are based on the empirical relations given by Chisholm (1973). Choices are provided to the user, to calculate these velocities, namely Armand (1959) correlation and Orkiszewski (1967) correlation. The reader is referred to Björnsson (1987) and Aunzo et al. (1991) for further details on input-output format of HOLA and the various correlations.

In this sub section, measured pressure and temperature profiles in the flowing wells RN-13b, RN-18 and RN-23 are analysed and feed zone productivity that matches the measured results are calculated for each well using the simulator, HOLA. The wellhead pressure and the bottomhole pressure together with the wellbore geometry are specified and the calculation proceeds from bottom of the well to the wellhead. It has to be pointed out that RN-13b and RN-23 are directional wells and the temperature and pressure profiles were plotted versus the true vertical depth and not the measured depth (see Table A.1).

6.4.2 RN-13b

The flowing temperature and pressure data measured on October 11, 2007 were selected for the HOLA simulation and plotted versus the true vertical depth. Figure 6.3 shows the calculated and measured temperature and pressure profiles for well RN-13b.

RN-13b was considered down to a depth of 2000 m with three feed zones at 1120 m, 1590 m and at the bottom (2000 m). A wellhead pressure of 41 bar-g was considered since it was the pressure measured during discharge with a bottomhole pressure of 127 bar-g. The production casing and liner diameters are 13 ⅜" and 9 ⅝", respectively. Enthalpy of 1800 kJ/kg, 1260 kJ/kg and 1280 kJ/kg were assumed for the feed zones at 1120 m, 1590 m and 2000 m, respectively.

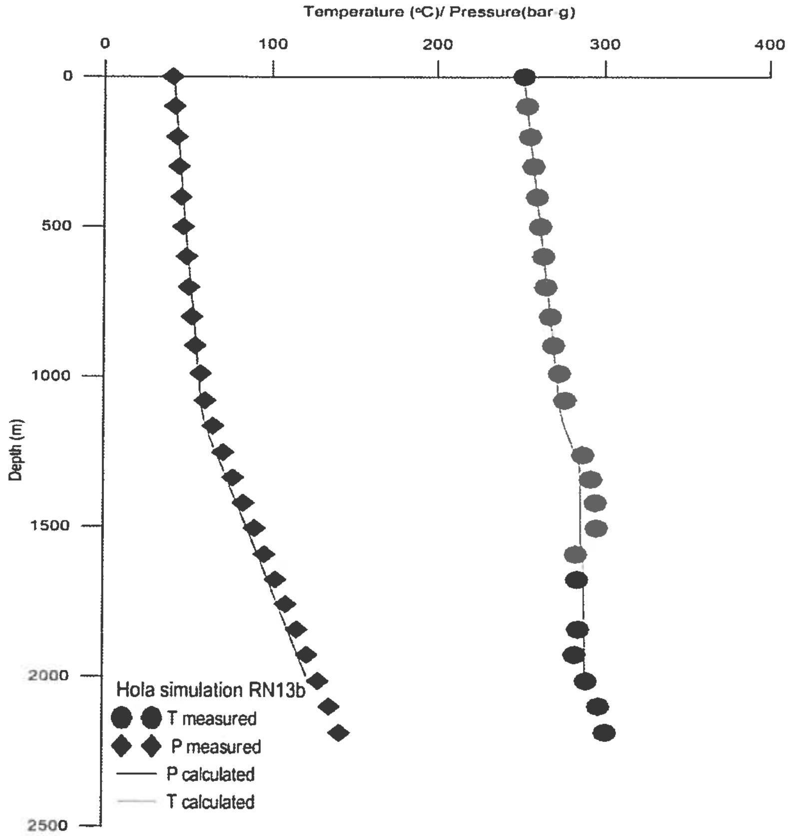

Figure 6.3: Calculated and measured temperature and pressure profiles for well RN-13b

A productivity index of $8 \cdot 10^{-12}$ m^3, $1.5 \cdot 10^{-12}$ m^3 and $2 \cdot 10^{-12}$ m^3 for the feed zones at 1120 m, 1590 m and 2000 m depth, respectively, matched reasonably well with the measured downhole profiles (Figure 6.3). The total productivity was calculated by adding all the productivity indices for the feed zones and was estimated at $11.5 \cdot 10^{-12}$ m^3 or about 5.8 (kg/s)/bar. The productivity index calculated from the simulator is in m^3 units and it is converted to (kg/s)/bar units by using equation (6.13).

The calculated wellhead enthalpy is 1780 kJ/kg which is higher than the one calculated during the discharge test. It could be due to the fact that the well had not fully recovered after the discharge test.

The wellhead total flow is 25 kg/s compared to 33 kg/s from the discharge test. The steam flow rate is 10 kg/s corresponding to about 5 MW_e. The slight difference between the enthalpy and flow rate results from HOLA and the discharge tests, respectively, could be due to the fact that the feed zone at the well bottom was not considered in the HOLA simulation or that the well had not fully recovered after the discharge test. The specified and calculated parameters for the simulation are presented in Appendix A.5.

6.4.3 RN-18

Figure 6.4 shows the measured and simulated flow profiles for the discharge test on August 11, 2005 for borehole RN-18. Two major feed zones are present in the well, one at around 750-800 m, just below the production casing, and the other at the well bottom at 1800 m depth. The calculated pressure and temperature profiles in Figure 6.4 are obtained by assuming a wellhead pressure of 32 bar-g and a bottomhole pressure of 117 bar-g. Enthalpy of 1520 kJ/kg and 1220 kJ/kg were assumed for the feed zones at 800 m and 1800 m depth, respectively.

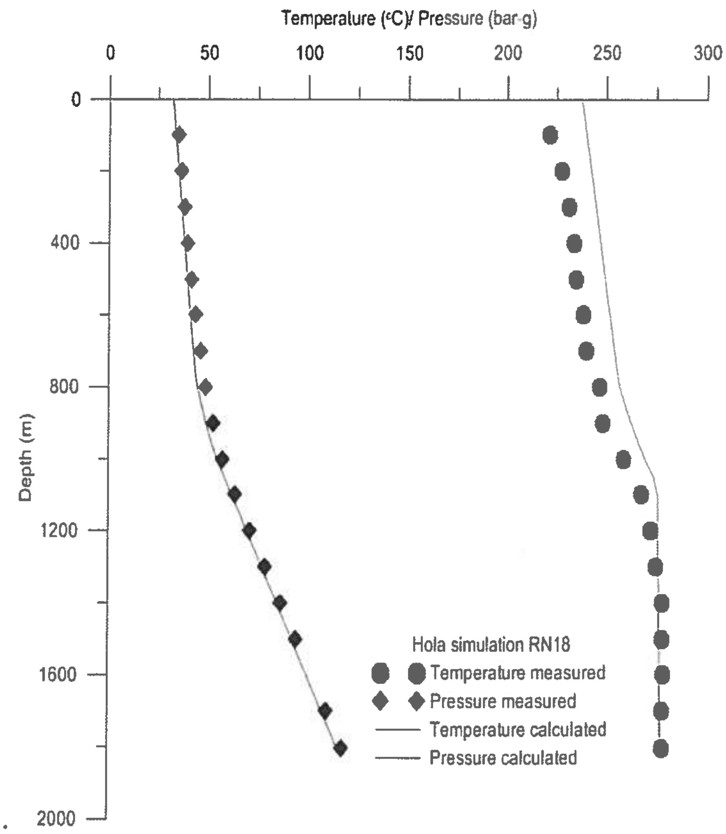

Figure 6.4: Calculated and measured temperature and pressure profiles for well RN-18

The simulation shows a good match for the pressure profile. For the temperature profile the match is close and the shift in the calculated temperature profile could be due to bad calibration of the instrument because there is boiling in the well. The simulation gives a total flow rate of 51 kg/s at the wellhead which is similar to the flow calculated during the discharge test (47 kg/s). The productivity index at 800 m depth and at the bottom is $1 \cdot 10^{-12}$ m^3 and $1.3 \cdot 10^{-11}$ m^3, respectively, giving a total productivity index of $1.31 \cdot 10^{-11}$ m^3 or about 7.34 (kg/s)/bar. This value is much higher than the one calculated during the discharge test. It could be due to the fact that the well had not fully recovered after the discharge test.

The calculated wellhead enthalpy is 1490 kJ/kg which is similar to the one calculated during discharge (1420 kJ/kg). The steam flow rate is 13 kg/s corresponding to about 7 MW_e. The specified and calculated parameters for the simulation are presented in Appendix A.5.

6.4.4 RN-23

Figure 6.5 shows measured and calculated temperature and pressure profiles for RN-23. Three feed zones are present in the well, at 750 m, 1200 m and 1730 m depth (true vertical depth). The bottom depth was considered at 1730 m instead of 1742 m. A pressure of 46 bar-g was required at the wellhead and a bottomhole pressure of 128.4 bar-g. Enthalpies of 1470 kJ/kg, 1280 kJ/kg and 1370 kJ/kg were assumed for the feed zones at 750 m, 1200 m and 1730 m depth, respectively.

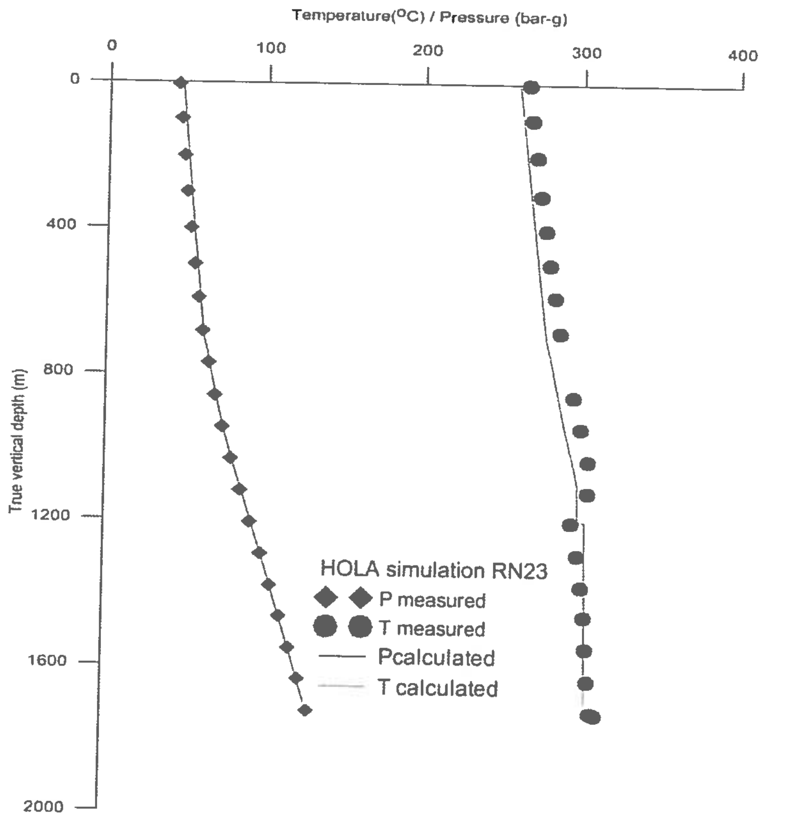

Figure 6.5: Calculated and measured temperature and pressure profiles for well RN-23

The results of the simulation indicate a total flow rate of 155 kg/s at the wellhead which is three times higher than the value calculated during vertical discharge of the well. This difference could be interpreted as the instability of the flow during vertical discharge. The productivity index at 750 m depth and at the bottom of the well is similar, $3 \cdot 10^{-11}$ m^3 but it is about 10^{-11} m^3 at 1200 m depth. Therefore, the total productivity for RN-23 is about $7 \cdot 10^{-12}$ m^3 or around 45.3 (kg/s)/bar.

The calculated wellhead enthalpy is 1452 kJ/kg which is in the same range as the 1410 kJ/kg calculated during discharge. The steam flow rate is 30 kg/s corresponding to about 15 MW_e. The calculated parameters for the simulation are presented in Appendix A.5.

6.5 Comparison between productivity and injectivity indices

Usually, well test data for both injection tests and production tests are evaluated and interpreted to determine the injectivity and productivity indices for a well. The productivity index, *PI* is the ability of the well to produce fluid while the injectivity index, *II* can be defined as the ease with which a fluid can be pumped into a borehole. The productivity and injectivity indices are key element in well analysis (Craft and Hawkins, 1959). They are defined as the absolute value of the ratio between the flow rate, Q and the difference between the static pressure, P_s and the flowing downhole pressure, P_f (Combs and Garg, 2000):

$$II, PI = \left| \frac{Q}{(P_s - P_f)} \right| \tag{6.14}$$

The productivity and injectivity indices are, therefore, usually considered to be the same in liquid fed wells but it is not always the case for two-phase feed zones due to the variations in the enthalpy and the viscosity of the flowing steam and water phase mixture (Grant and Bixley, 2011). However, knowing the injectivity and productivity indices of a wellbore, it may be possible to devise rules to relate the two.

In this section, injectivity indices from injection tests and productivity indices from discharge tests for several high temperature geothermal fields worldwide are considered (Garg and Combs, 1997; Axelsson et al., 2006; Grant, 2008; Houssein & Axelsson, 2010). The data can be found in Table A.2 in Appendix A.4.

The injectivity index for each well is plotted versus its productivity index in Figure 6.6. The injectivity and productivity indices for RN-18 and RN-23 are both plotted in Figure 6.6. Two relationships from the literature (Garg and Combs, 1997; Grant and Bixley, 2011) were considered. Garg and Combs (1997) suggested that PI=II and Grant and Bixley suggested that PI=II/3 or PI= II/5.

To compare the productivity and injectivity correlations for these high temperature geothermal fields, two lines representing the selected PI versus II relationship are plotted to see where RN-18 and RN-23 fit the best. Figure 6.6 shows a considerable scatter of the data. It can be seen that RN-18 falls into the relationship PI=II/3 while RN-23 shows a higher productivity index compared to its injectivity index. The low value of the productivity index for RN-18 could be explained by a bad calibration of the pressure gauges leading to errors on pressure measurements at the downhole. However, this is not the case for RN-23 which shows a higher productivity index. This could be due to the fact that RN-23 is drilled into a steam cap as pointed out in previous chapters.

From the Figure, it appears also that the productivity indices for the Reykjanes boreholes fall more or less into the same relationship PI=II/3 with a considerable scatter.

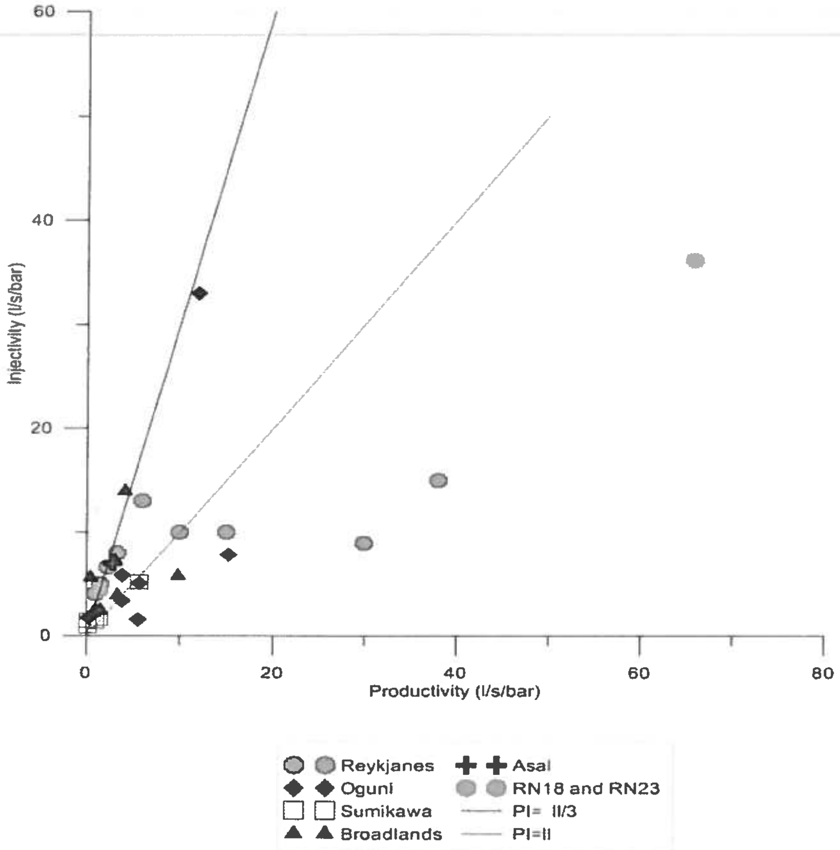

Figure 6.6: Comparison of productivity and injectivity index for several high temperature geothermal fields worldwide

7 Resource estimate

7.1 Volumetric assessment

The most simple and preliminary assessment of a reservoir is the volumetric method. It is used to estimate the stored heat and recoverable power reserves in the early life of geothermal reservoirs. It can only be considered as the first modeling method since it neglects the response of the reservoir to production. This method involves estimating the energy production potential of a geothermal system, based on the available data and present technology.

The volumetric method assumes that the reservoir rocks are porous and permeable and that the water mass extracted from the reservoir extracts the heat from the overall volume of the reservoir. No recharge of reservoir fluids or flux of thermal energy to the reservoir volume is assumed. The following equation is used to calculate the power potential of a homogeneous reservoir by estimating the amount of energy that can be extracted and converted to electricity (Muffler and Cataldi, 1978)

$$E_t = E_r + E_w = (1-\varphi)\rho_r C_r V(T_r - T_0) + \varphi\rho_w C_w V(T_r - T_0) \tag{7.1}$$

Where T_r is the average reservoir temperature (°C) and T_o the reference temperature (°C) that is the endpoint of the thermodynamic process utilizing the fluid. V=Ah is the reservoir volume in m^3, A is the surface area in m^2 and h is the thickness of the reservoir in m. E is the heat energy (J); φ is the porosity of the rock (%), C is the specific heat (J/(°C kg)) and ρ is the density (kg/m^3). The subscripts, r and w refer to rock and water, respectively.

E_t defined by equation (7.1) is usually referred to as the accessible resource base and it can be converted to recoverable power in MW$_e$ by the following equation:

$$P = \frac{E_t\, R_f\, \eta}{L\, t} \tag{7.2}$$

where, P = Power plant capacity (MW$_e$)
R_f = Recovery factor
η = Conversion efficiency (%)
L = Power plant capacity factor (%); and
t = Power plant life (years).

Here, t is the power plant life, represents the fraction of the total time in which the power generation is in operation and gives an average output capacity, P in MW$_e$; η is the conversion efficiency to convert the recovered heat to electricity, R_f is the recovery factor used to determine the amount of heat that can be extracted and L is the power plant capacity factor that combines the plant availability and capacity.

The volumetric method was applied to the Reykjanes field. The purpose was to estimate the electricity capacity assuming 30 year and 50 years power plant life, respectively. Since the reservoir parameters are uncertain, the Monte Carlo simulation was used.

7.2 Monte Carlo simulation

The Monte Carlo calculation is based on a generation of multiple trials to determine the expected value of a random variable. This method relies on a specified probability distribution of each of the input variables and generates an estimate of the overall uncertainty in the prediction due to all uncertainties in the variables (Kalos and Whitlock, 2008). The common distribution functions of poorly known parameters are the rectangular distribution, the triangular distribution, the uniform distribution and the normal distribution. Normal and triangular distributions are suitable when actual data are limited and it is known that they fall near the centre of the limits. In the absence of any other information, rectangular distribution is a reasonable default model. By choosing one random value for each variable out of their probability distributions one possible outcome of the volumetric method can be calculated. To estimate the electric production capacity of the reservoir, two different cases, case I and case II, described below, were considered.

7.2.1 Surface area of the geothermal system

The size of the area considered in this study is the prospect area of the Reykjanes geothermal field. The size of the Reykjanes geothermal system is not yet fully known. Therefore, defining the base of the reservoir can be difficult, even when many wells have been drilled (Grant and Bixley, 2011). Literature from different authors (Björnsson et al., 1970; Pálmason et al., 1985 and Sigurdsson, 2010) assumes different size of the system that can vary between 1 km^2 and 11 km^2. From the INSAR results for the Reykjanes peninsula, a subsidence in an area of more than 16 km^2 is measured (Jónsson, 2009). This indicates that the size of the geothermal system may be larger than what earlier studies indicated (Sigurdsson, 2010).

Information on the extent of a geothermal prospect is usually assumed from the resistivity measurements. For this study, two approaches to define the reservoir area are considered: The area around successful wells which correspond to the low resistivity sheet at 300 m depth b.s.l., an area of 2 km^2 and the area corresponding to the low resistivity sheet at 800 m to 1000 m depth b.s.l., an area of about 11 km^2. The two areas are referred to as case I and case II, respectively. Figure 7.1 shows the low resistivity sheets in Reykjanes.

The wells used in this study are within the two surface areas (Figure 7.2). RN-12, RN-13b, RN-18 and RN-23 are drilled in the small area of geothermal surface manifestations while, RN-17b and RN-29 are drilled outside the alteration area but within the low resistivity sheet at 800 m to 1000 m depth b.s.l.

The area considered for the Monte Carlo simulation is therefore based on these two cases. For case I, it is assumed that the minimum area is 1 km^2 (Björnsson, 1970) and the maximum area is 2 km^2 (Pálmason et al., 1985); and for case II, it is assumed that the minimum area is 1 km^2 and the maximum area is 11 km^2 (Karlsdóttir, 2005). For both cases, the most probable value is taken as 2 km^2.

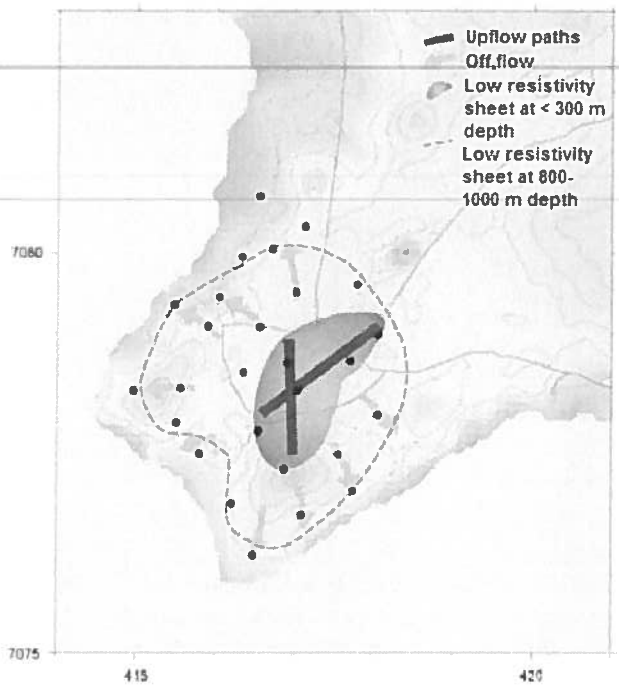

Figure 7.1: TEM resistivity measurements in the Reykjanes geothermal area (Karlsdóttir, 2005). The orange area shows the geothermal surface manifestation referred to as case I and the red dash contour area shows the low resistivity area referred to as case II.

7.2.2 Temperature

The temperature parameter represents the reservoir temperature that was estimated from the temperature profiles for RN-12, RN-17b, RN-18, RN-23 and RN-29 (Figure 5.1). From the temperature profiles, a minimum temperature of 280 °C, a most likely temperature of 300 °C and a maximum temperature of 340 °C were considered for both case I and case II.

7.2.3 Reservoir thickness

The thickness parameter was estimated from the temperature profiles. The minimum depth was considered at the level of the production casing and the maximum level was considered at the well bottom. For case I, the most likely value is assumed to be at 2000 m depth with a minimum of 800 m and a maximum of 2500 m. For case II, the most likely value is assumed to be at 2500 m depth with a minimum of 1000 m and a maximum of 3000 m.

7.2.4 Recovery factor

The thermal recovery factor determines the fraction of the energy that can be extracted from the reservoir rock. Historically, a constant recovery factor of 0.25 has been used for uniformly porous and permeable geothermal reservoirs. More recent analysis of data from fractured reservoirs indicates that the recovery factor is closer to 0.1, with a range of approximately 0.05 to 0.2. In general, this apparent discrepancy in the recovery factor reflects the contrast in thermal energy recovery from complex, fracture-dominated reservoirs compared to uniform, high-porosity reservoirs (Williams, 2007).

For case I, a most likely recovery factor of 0.2 was assumed with a minimum of 0.1 and a maximum of 0.25. This is because for case I which corresponds to a surface area of 2 km^2, the resource is fairly well known with similar reservoir characteristics (RN-12, RN-13b, RN-18 and RN-23).

For case II, which corresponds to the low resistivity area of 11 km^2, the recovery factor was assumed to be as low as 0.1 with a minimum of 0.05 and a maximum of 0.2. A low recovery factor was considered here because wells RN-17b and RN-29, drilled outside the surface alteration area, did not show good permeability despite the high temperature at depth.

7.2.5 Conversion efficiency

Figure 7.2 was used to estimate the conversion efficiency value knowing the reservoir temperature range considered in sub section 7.2.2. Therefore, the most likely conversion efficiency value was estimated to be 14% varying from a minimum value of 13% and a maximum value of 15%.

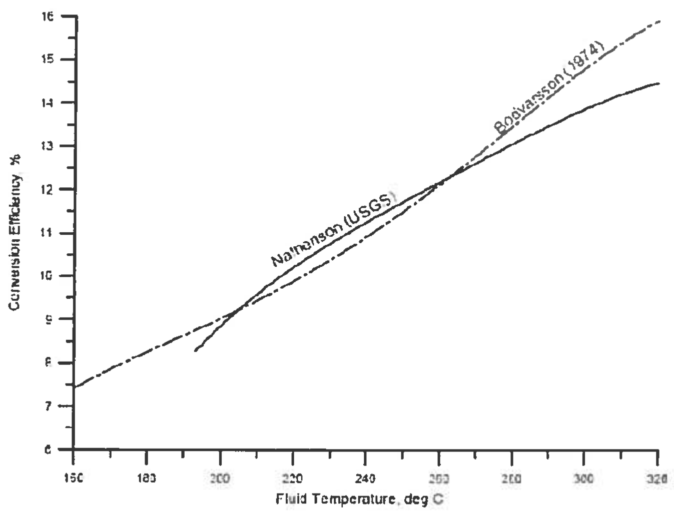

Figure 7.2: Correlation between thermal conversion efficiency and reservoir temperatures (Nathenson, 1975; Bödvarsson, 1974)

7.2.6 Results

In the calculation, a rejection temperature of 40 °C was considered. The porosity of basalt was assumed to be 10% for both case I and case II. The fluid density was calculated by considering the reservoir temperatures and the salinity of the Reykjanes fluid. The parameters used to calculate the power potential and the probability distribution functions used to calculate them are summarized in Table A.3.

In this study, two life time scenarios of 30 years and 50 years, respectively, were run using the Monte Carlo simulation @RISK spreadsheet-based software (Palisade Corp., 2004). An estimate of the electrical power, which could be produced from the Reykjanes geothermal field is calculated according to equation (7.1) and (7.2) by using the parameters in Table A.3. The simulation runs were 10,000. Table 7.1 shows the statistical distribution for the two production periods for case I and case II, respectively.

Table 7.1: Estimation of the power generation capacity for the Reykjanes geothermal field based on Monte Carlo simulation

Size of the geothermal area	Estimated capacity MW_e			
	30 years		50 years	
	A = 2 km^2	A = 11 km^2	A = 2 km^2	A = 11 km^2
Median	64	110	39	68
Mean	65	132	39	79
Maximum	138	640	85	320
90% confidence interval	34-102	38-290	20-61	23-174

The calculated parameters (Figure A.12 and Figure A.13) for case I indicate that the power production for the Reykjanes geothermal field lies with 90% confidence interval between 34 MW_e and 102 MW_e for a recoverable heat used with a most likely value of 65 MW_e and between 20 MW_e and 61 MW_e with a most likely value of 39 MW_e for 30 years and 50 years, respectively.

For case II, the model predicts with 90% confidence interval, a power production of 38 MW_e to 290 MW_e with a most likely value of 132 MW_e and between 23 MW_e and 174 MW_e with a most likely value of 79 MW_e for 30 years and 50 years, respectively (Figure A.14 and Figure A.15).

8 Conclusions

The purpose of this study was to demonstrate the importance of well testing in the evaluation of geothermal resources with a particular emphasis on the methodology and the interpretation of temperature and pressure profiles at well completion and during discharge tests. Various methods were selected to estimate the well and reservoir properties as well as the characteristics of the Reykjanes geothermal field in southwest Iceland. The Reykjanes geothermal field was used as an example for the application of the methodology presented in the thesis.

Step-rate injection tests reveal a permeability distribution of the Reykjanes reservoir. Temperature and pressure logs interpretation contributed to the estimation of the formation temperature and the initial reservoir pressure as well as the location of the feed zones or zones of permeability. The flow characteristics of selected wells are estimated from discharge tests and also simulated to evaluate the generating capacity of individual wells. Finally, a volumetric assessment based on well-test data is used to predict the electrical generation capacity of the Reykjanes geothermal system. It important to point out that the results presented in the thesis do not fully describe the Reykjanes geothermal reservoir since all wells were not considered.

The summary of the results from this study is given in Section 8.1, the results are discussed in Section 8.2 and the recommendations based on this are made in Section 8.3.

8.1 Summary of results

The step-rate injection tests were performed for wells RN-17b, RN-18 and RN-23. The estimated value of the permeability-thickness ranges from 1 Dm to 30 Dm for the Reykjanes reservoir. The storativity for the system varies between $5 \cdot 10^{-8}$ m/Pa and $2 \cdot 10^{-7}$ m/Pa. The skin factor is negative varying between -0.7 and -2.5 indicating stimulated wells and presumably fractured reservoir. Injectivity indices are different for each well, ranging from 1 (L/s)/bar to 36 (L/s)/bar indicating heterogeneity in the permeability of the reservoir.

Temperature and pressure profiles were analysed for RN-12, RN-17b, RN-18, RN-23 and RN-29 and the initial reservoir pressure and the formation temperature estimated. The formation temperatures vary between 280 °C and 320 °C with the highest value of 340 °C for RN-17b indicating a high temperature geothermal field. Boiling is observed at a depth of 500 m to 1000 m for RN-12, RN-18 and RN-23 indicating a steam cap or two phase reservoir. Below 1000 m depth, a single-phase liquid is dominating. This corresponds well with the literature (Arnórsson, 1995). RN-29 indicates a possible temperature inversion or slow temperature recovery below 1750 m depth which could indicate that the outer boundary of the system has been reached. RN-17b and RN-29 indicate a hot reservoir zone but rather impermeable rock.

For Reykjanes, the initial reservoir pressures are quite different suggesting heterogeneity in the reservoir. The pressure in RN-17b was low as compared to the other wells while the pressure in RN-23 was the highest one.

Discharge tests were performed for RN-13b, RN-18 and RN-23 and the results for RN-13b, and RN-18 indicate a power generating capacity of approximately 10 MW_e per well for the productive part of the Reykjanes reservoir. The capacity of RN-23 could not be estimated during the discharge tests since the well was discharged directly to the atmosphere without steam and water separation.

Temperature and pressure logs for wells RN-13b, RN-18 and RN-23 measured during discharge tests were simulated using the HOLA wellbore simulator to estimate the capacity of the wells during discharge as well as their productivity indices. The simulation results compared reasonably well with the flow characteristics calculated from the discharge tests. The capacity of the wells varies between 5 MW_e and 15 MW_e. RN-23 shows a high capacity of 15 MW_e. However, the comparison of the productivity indices with the ones calculated during discharge shows some variations. This can be due to the fact that the well had not fully recovered after the discharge test and/or bad calibration of the instrument (pressure gauges). Another reason could be that more feed zones are affecting the behaviour of the wells.

Different relationships between injectivity and productivity indices for different high temperature geothermal fields worldwide were considered in order to estimate the II/PI correlation for the two wells RN-18 and RN-23 in the Reykjanes geothermal field. The relationships seem to indicate that PI=II/3 for RN-18 but RN-23 shows a higher productivity index than the injectivity index. Other wells from the Reykjanes field indicate a relation of PI=II/3 with a considerable scatter.

The Monte Carlo simulation for case I, discussed in Chapter 7, predicts with 90% confidence interval a generating capacity between 34 MW_e and 102 MW_e , with a most likely value of 65 MW_e and between 20 MW_e and 61 MW_e , with a most likely value of 39 MW_e for 30 years and 50 years, respectively. For case II, also discussed in Chapter 7, the model predicts with 90% confidence interval a generating capacity of 38 MW_e and 290 MW_e , with a most likely value of 132 MW_e and between 23 MW_e and 174 MW_e , with a most likely value of 79 MW_e for 30 years and 50 years, respectively.

Considering a generating capacity of 290 MW_e , the maximum number of wells to be drilled in the area could be estimated at about 30 wells.

8.2 Discussion

The questions that were posed in the introduction of the thesis can be answered here. What are the current approaches and methods used in well testing? What kind of information is expected at different stages and well testing and how can this information contribute to the development of a new geothermal field? How can the results of well testing be used to estimate the production capacity of a geothermal field? How can the results be used in guiding decision making for the development of a field?

The pressure is the most important parameter and it is its response to perturbation that gives information on the well and the reservoir properties through well testing. The reservoir pressure is an indication of how much the potential energy the reservoir contains.

From the results of this study, it can be said that the permeability of a geothermal reservoir is not uniform; it varies for different parts of the reservoir. A well can be drilled into a high temperature part of a reservoir but if the permeability is low, the well is not productive like in the case of wells RN-17b and RN-29. Therefore, the permeability is a direct indication of the well productivity and it is a parameter that is telling if a well is good or bad depending on the utilisation of the fluid. The permeability-thickness is telling how easily the reservoir fluid can flow to a well and help designing well spacing and deciding the number of wells to be drilled.

The permeability can be estimated during the injection test since it depends on the injectivity index. When the injectivity index is low or high, the permeability is assumed to be low or high. However, the injectivity index of a well is not always the same as the productivity index as usually suggested, particularly for high temperature geothermal fields as indicated in the thesis. The productivity index can be as low as one third the injectivity index for the same well as seen for RN-18. This shows that a well with high injectivity index cannot always be considered to have a high productivity index especially for high temperature geothermal fields. However, exceptions can be found where the productivity index is higher than its injectivity index like for well RN-23. The injectivity and productivity indices must therefore, always be measured when testing a well. A conservative estimate assuming that PI=II/3 can be considered for the Reykjanes field.

The simulation of the discharge data shows that the productivity index can be estimated from the results and that the results from the simulator represents better the productivity of the wells. For RN-18, the discharge test shows a small productivity index 1.4 (kg/s)/bar while the HOLA simulator shows a productivity index of 7 (kg/s)/bar. The productivity index value from HOLA is a better indication since for HOLA, the pressure at the bottom of the well is a fixed input in the simulation, allowing accurate calculations. However, the simulation process is long and this method cannot be used when information is needed fast.

To know the storativity is important because it is an indication of the fluid reserves in the reservoir. If the storativity is small, the resource development will not sustain a long production period. Also, a high value of storativity can tell if a well is drilled into a steam cap or not.

The temperature of the fluid or the corresponding enthalpy can assist in deciding how to utilise the resource (electricity production or some other utilisation), and/or if the power plant should use steam turbine or binary units. The reservoir fluid in the Reykjanes geothermal field has high temperature. Therefore, it is used for electricity production. Analyses of the formation temperature and information on the initial reservoir pressure can assist in determining the fluid flow directions in the reservoir.

The output curves give an indication about the ability of a well to produce and about the well capacity in MW_e. This can lead to decisions on the number of wells required to develop a field. But before a decision is made, the reservoir must be delineated by drilling wells to confirm the productive size of the reservoir. It was shown here that RN-17b and RN-29, drilled recently at the outskirts of the surface alteration zone are not productive and RN-29 indicates that the outer boundary has been reached. This shows that additional wells are needed to delineate the reservoir. A concentration of wells in the same area can lead to a pressure drawdown in the system as indicated in the Reykjanes field from the pressure profiles.

The results of well testing, both at completion of the well and during discharge test, can be used to develop a conceptual model of the field by integrating geological, geochemical and geophysical data. Furthermore, those results can be used to monitor the energy output and the reservoir response during production.

At the beginning of a field exploration, the power production capacity is roughly estimated by the volumetric method knowing a range of parameters for the reservoir. This estimate can be used for commercial purposes to interest private companies in developing a field. The volumetric method does not consider the recharge of the reservoir fluid. The Monte Carlo simulation involves an uncertainty in the results. However, the 90% confidence interval can give an indication of the lower limit of the capacity of the field. The results found for the two different cases indicate that possibly the Reykjanes field is larger. However, it might also be the other way around. Other simple modelling like the lumped parameter modeling can give a better estimate based on available data during production.

8.3 Recommendations

Recommendations can be made from the results and discussion above:

- Additional tests have to be carried out, such as interference tests to understand the connection between the wells, and tracer tests to understand the pathways of the fluid flow in the reservoir.
- Long term discharge tests are recommended for better analysis of the reservoir properties.
- The volumetric assessment gives a rough estimate of the field capacity and does not reveal a clear overall capacity of the area. The results indicate that the extent of the reservoir must be defined more clearly. It has been observed that the wells considered outside the surface alteration area do not seem to be productive (RN-17b and RN-29). It is recommended that before expanding the Reykjanes power plant as planned, more wells should be drilled and tested to define the outer boundary of the reservoir.
- If continuous well flow is limited because of time and other constraints, the wellbore simulation is a good tool to compute the performance of the well when reliable production data together with pressure and temperature profiles are available.
- It is recommended to include wellbore direction to the wellbore geometry option in HOLA to better simulate directional wells.
- Finally, it would be interesting to analyse the well test data using the new deconvolution analysis method and use it as a diagnostic tool to confirm the results from the conventional methods.

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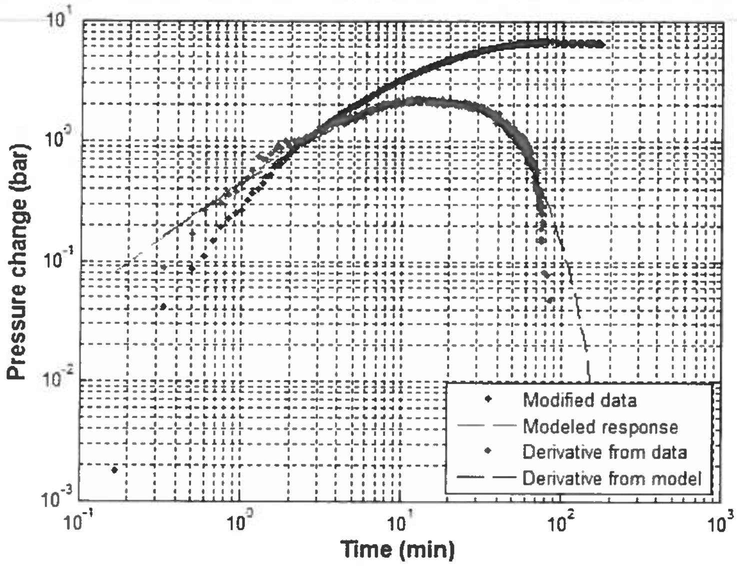
A. Appendix

A.1 Wellbore characteristics

Table A.1: Characteristics of Reykjanes wells.

Well	Measured depth (m)	True vertical depth (m)	East (m)	North (m)	Elevation (m.a.s.l.)	Production casing depth (m)	Remarks
RN-12	2506		318815	374154	18.1	842	Vertical well
RN-13B	2530	2200	318424	374503	18.2	818	Directional well
RN-17B	3077	2804	318072	373573	12.7	892	Directional well
RN-18	1815		319066	374412	23.1	750	Vertical well
RN-23	1924	1742	318488	374177	16.8	701	Directional well
RN-29	2837		317446	374756	20.0	901	Vertical well

A.2 Injection test



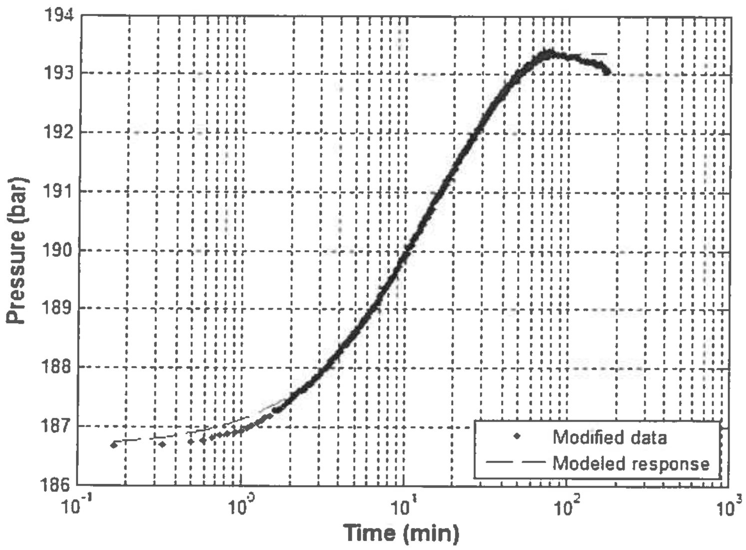
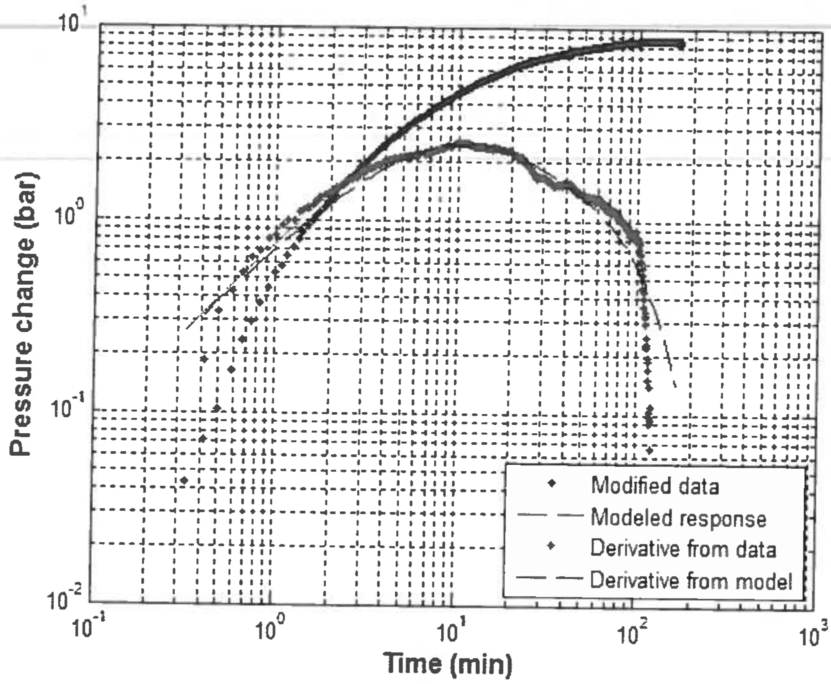


Figure A.1: Fit between model and selected data on log -log scale and log-linear scale for step 1 for well RN-17b.



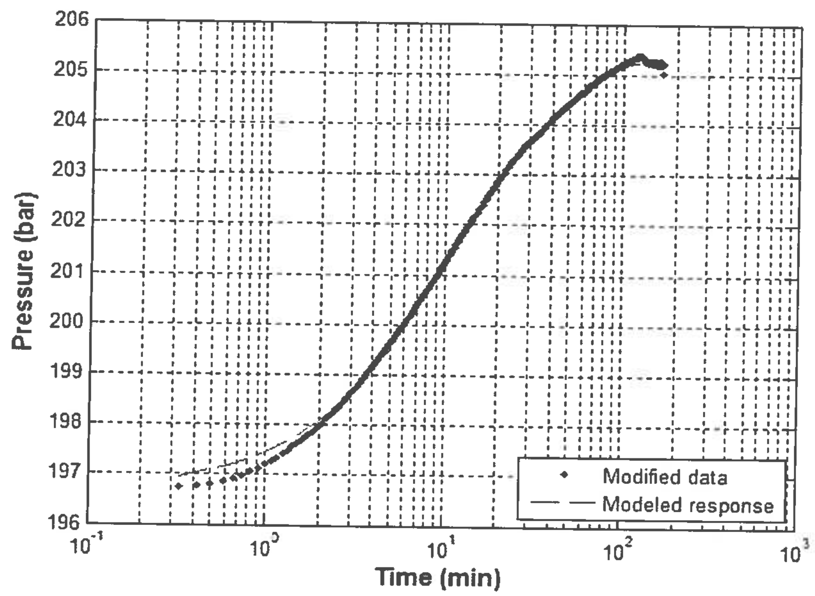
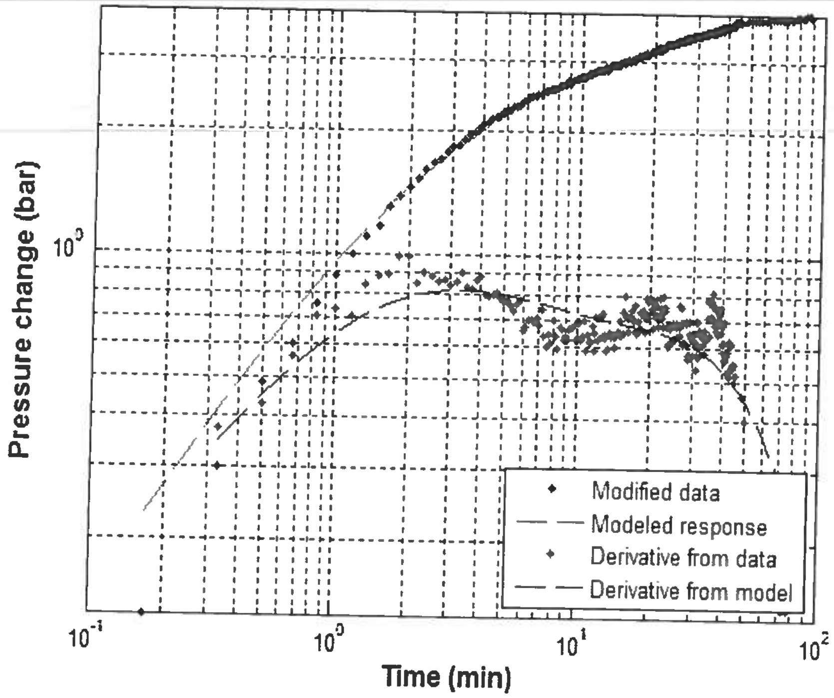


Figure A.2: Fit between model and data on log -log scale and log-linear scale for step 2 for well RN-17b.



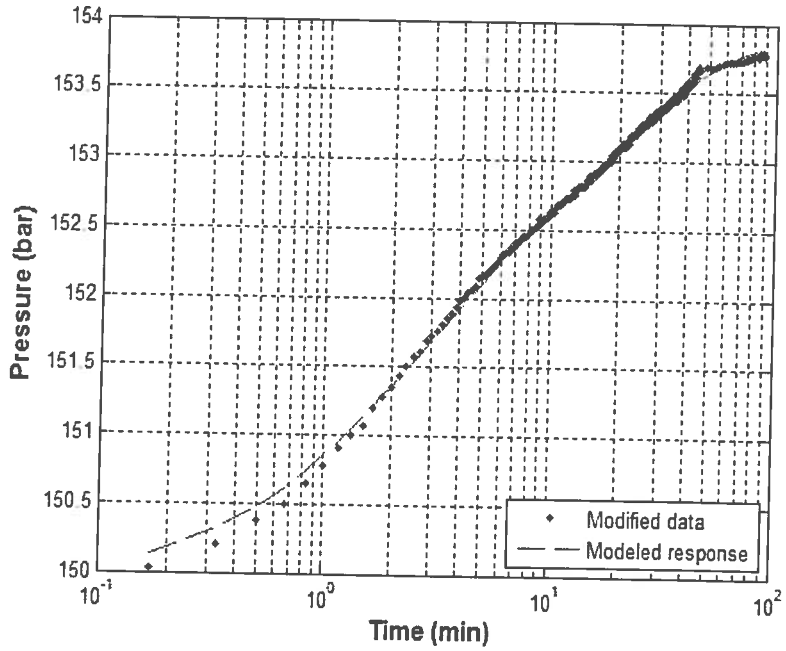
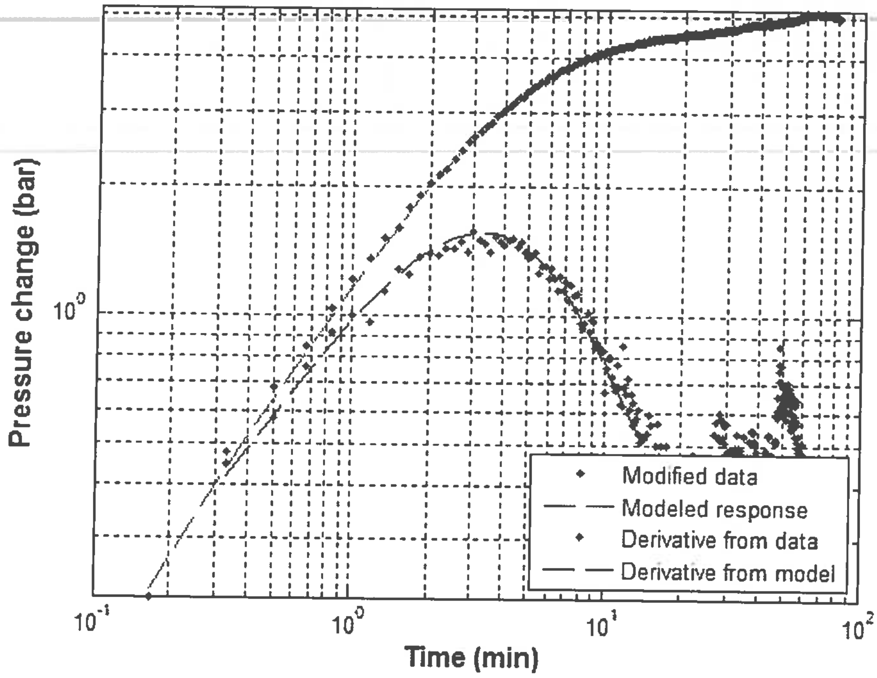


Figure A.3: Fit between model and data on a log- log scale and log-linear scale for step 1 for well RN-18.



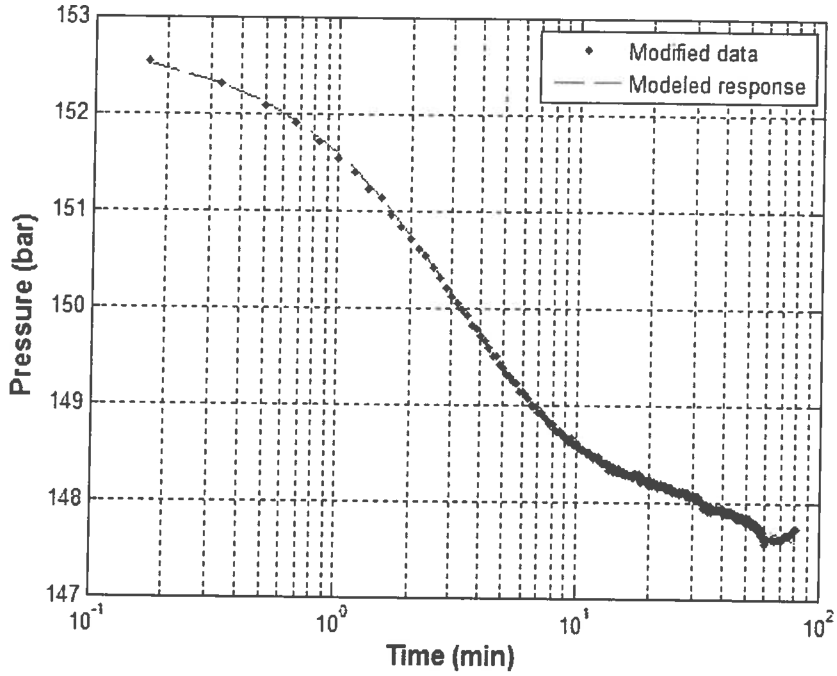
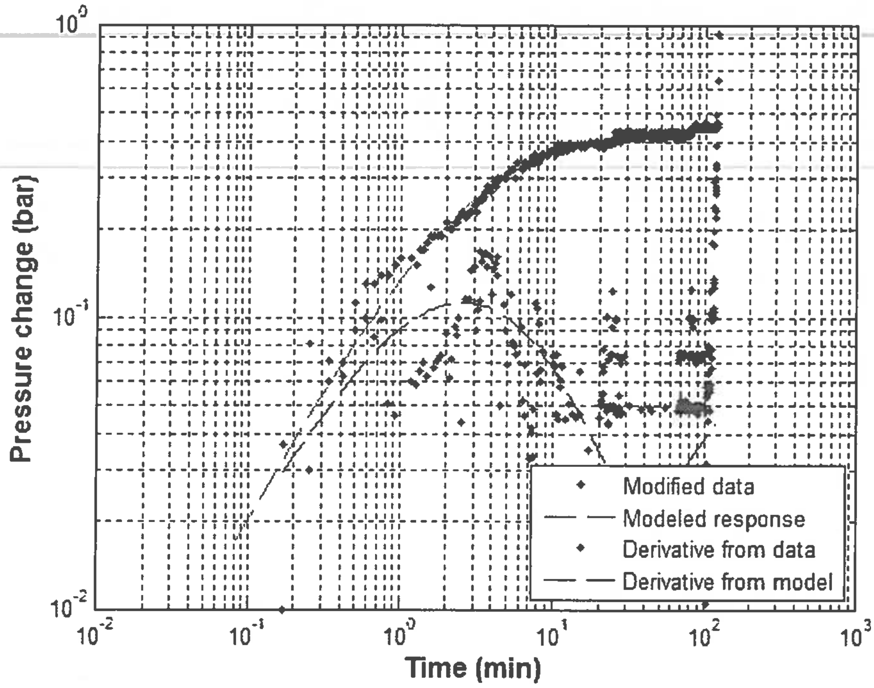


Figure A.4: Fit between model and data on a log- log scale and log-linear scale for step 2 for well RN-18.



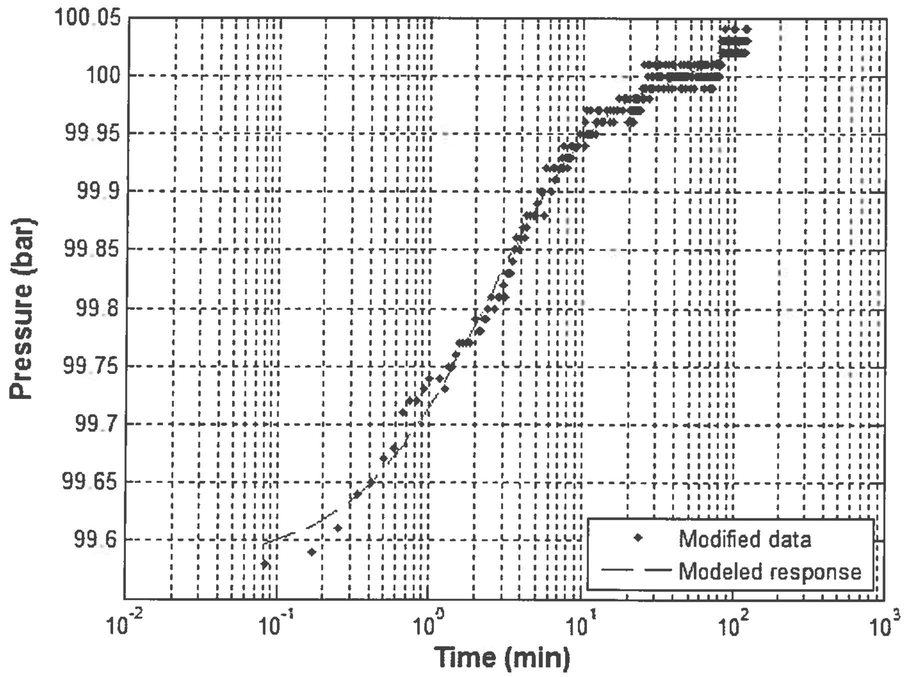
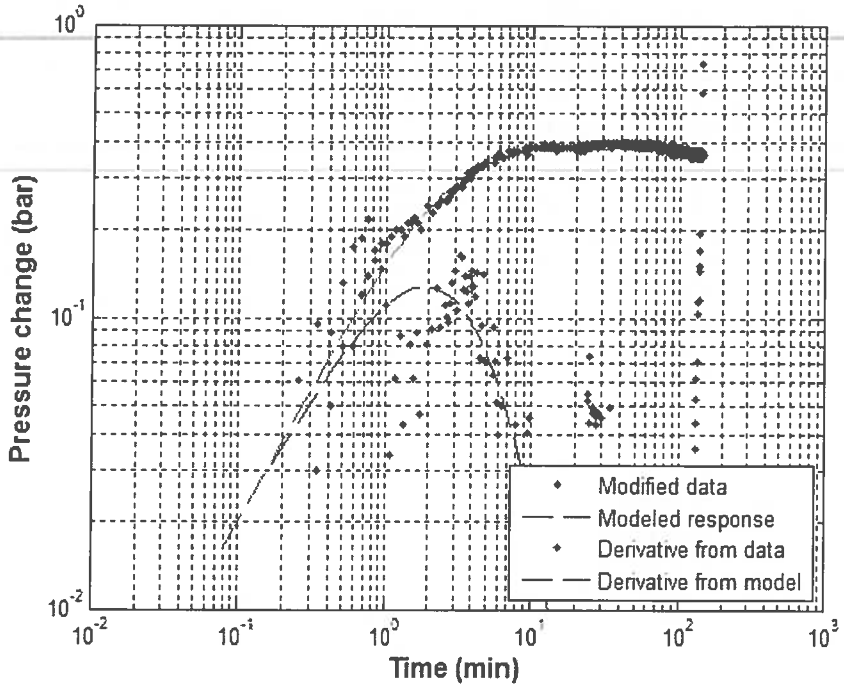


Figure A.5: Fit between model and data on log-log scale and log-linear scale for step 2 for well RN-23.



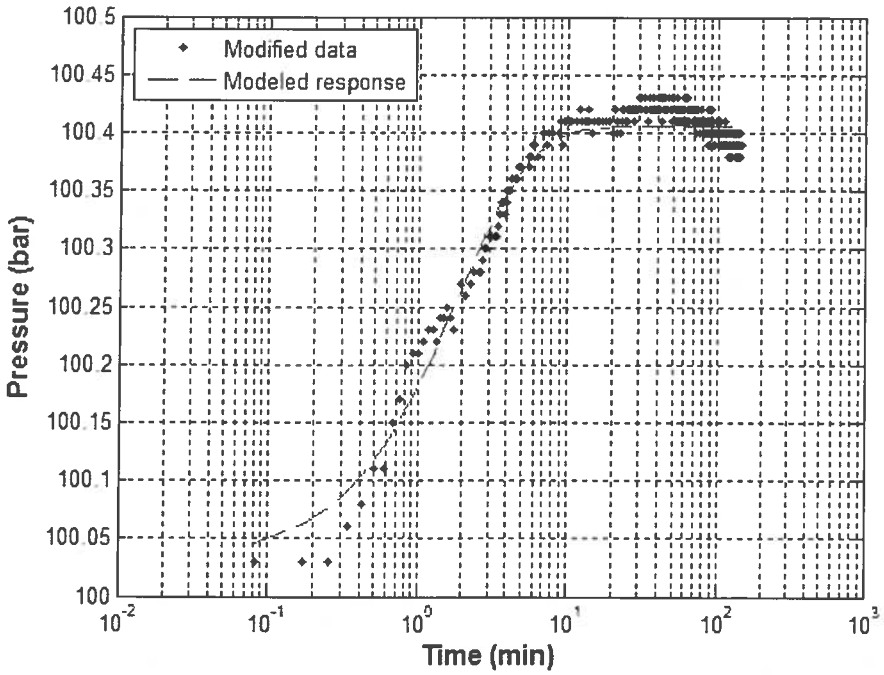
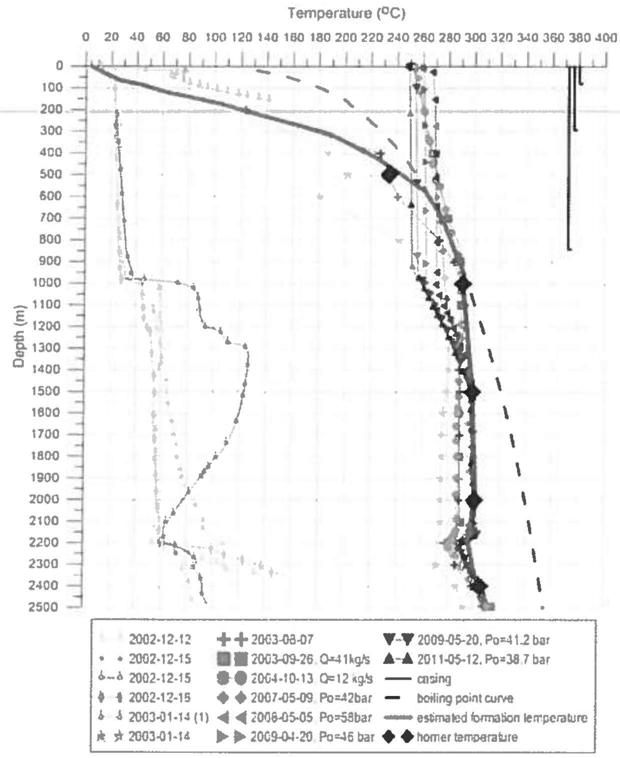


Figure A.6: Fit between model and data on log -log scale and log-linear scale for step 3 for well RN-23.

A.3 Temperatures and pressures profiles



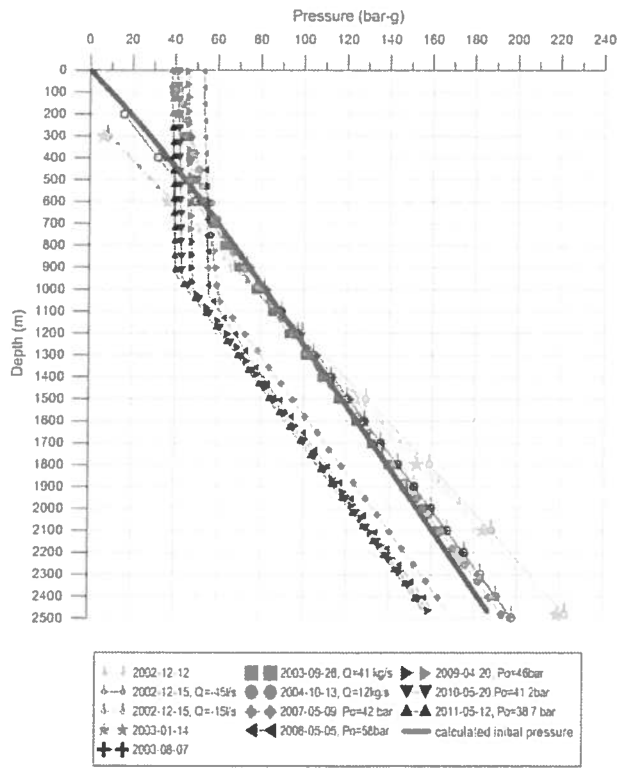
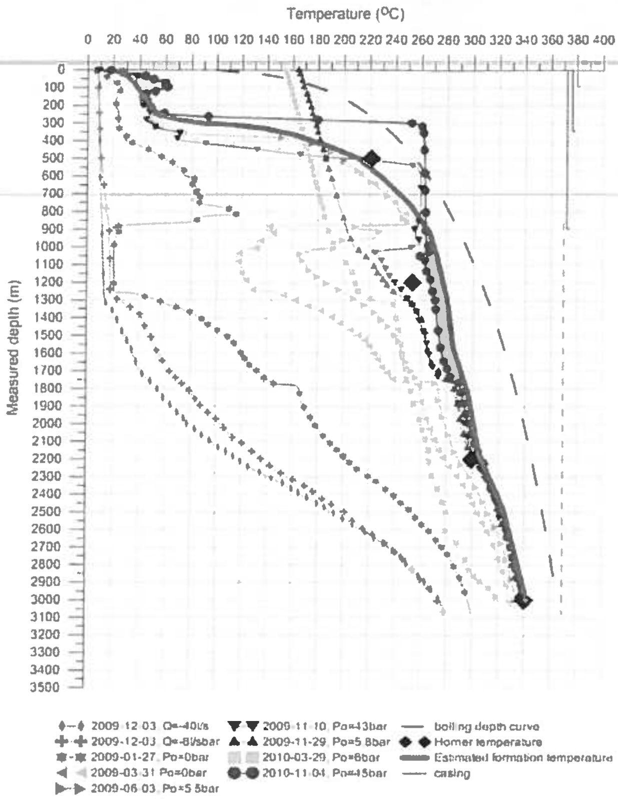


Figure A.7: Estimation of the reservoir temperature and pressure for well RN-12.



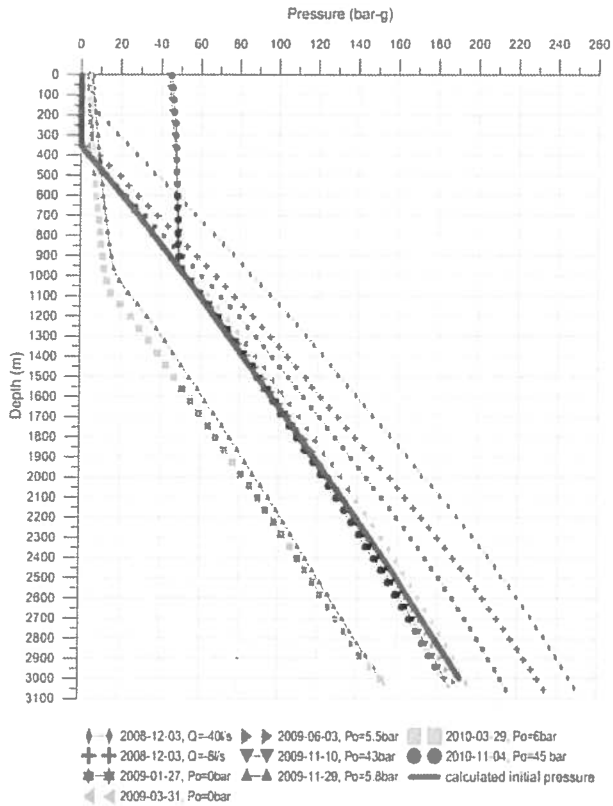
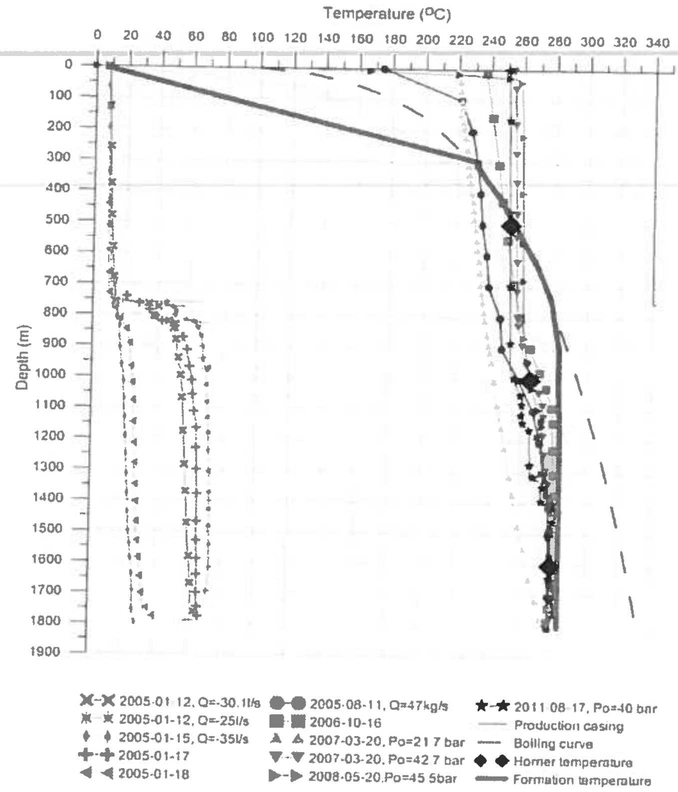


Figure A.8: Estimation of the reservoir temperature and pressure for well RN-17b.



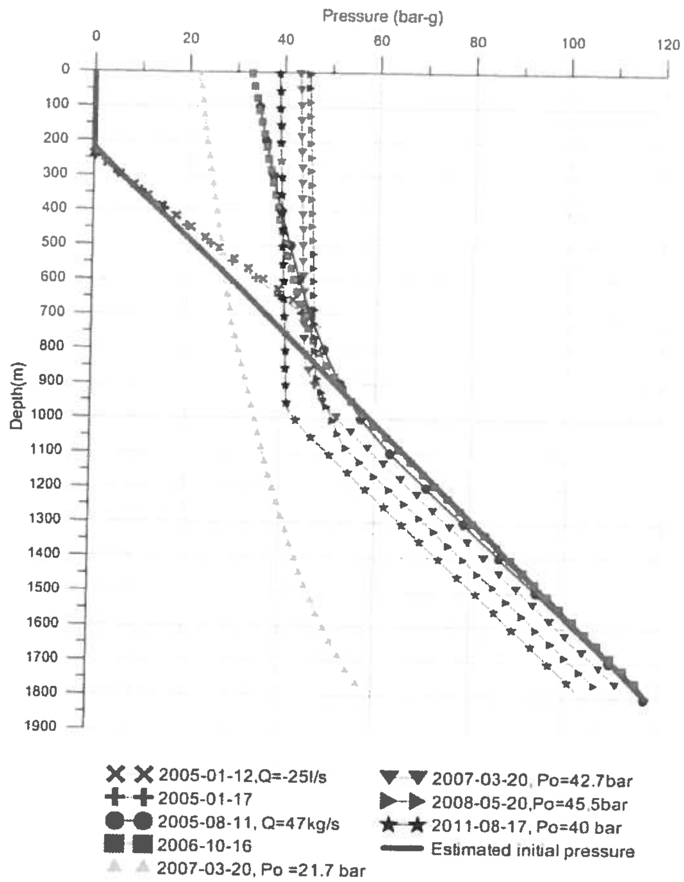


Figure A.9: Estimation of the reservoir temperature and pressure for well RN-18.

A.5 Hola results

Well RN-13b

Wellhead pressure (bar-a)	:	41.04
Wellhead temperature (°C)	:	251.85
Wellhead dryness (%)	:	40.15
Wellhead enthalpy (kJ/kg)	:	1779.38
Wellhead total flow (kg/s)	:	25.05

Feedzone	Depth (m)	Flow (kg/s)	Enthalpy (kJ/kg)	Resv.Press (bar-a)	Saturation (m3/m3)	Prod.Index (kg/s/m3)
1	1120.0	7.60	1800.00	62.90	.00	.800E-11
2	1590.0	7.42	1260.00	97.90	.00	.150E-11
3	2000.0	10.03	1280.40	127.80	.00	.200E-11

Depth (m)	Press (bar-a)	Temp (°C)	Dryness (%)	Hw	Hs	Ht	Vw	Vs	Dw	Ds	Rad (mm)	Reg
				----(kJ/kg)---			----(m/s)----		--(kg/m3)--			
0	41.0	251.9	40.1	1095	2800	1779	1.91	6.91	796.4	20.6	160	Sl
50	41.7	252.8	40.0	1100	2800	1780	1.88	6.78	794.9	21.0	160	Sl
100	42.4	253.8	39.9	1105	2799	1780	1.86	6.67	793.4	21.4	160	Sl
150	43.1	254.8	39.7	1109	2799	1781	1.83	6.55	791.9	21.7	160	Sl
200	43.8	255.8	39.6	1114	2798	1781	1.80	6.43	790.4	22.1	160	Sl
250	44.6	256.8	39.5	1119	2798	1782	1.78	6.32	788.8	22.5	160	Sl
300	45.3	257.8	39.3	1124	2797	1782	1.75	6.21	787.3	22.9	160	Sl
350	46.1	258.9	39.2	1129	2797	1783	1.72	6.10	785.7	23.3	160	Sl
400	46.8	259.9	39.0	1134	2796	1783	1.70	5.99	784.1	23.7	160	Sl
450	47.6	260.9	38.9	1139	2796	1784	1.68	5.88	782.5	24.1	160	Sl
500	48.4	261.9	38.8	1144	2795	1784	1.65	5.78	780.9	24.5	160	Sl
550	49.2	262.9	38.6	1149	2795	1785	1.63	5.68	779.3	24.9	160	Sl
600	50.0	263.9	38.5	1155	2794	1785	1.61	5.58	777.7	25.4	160	Sl
650	50.9	265.0	38.3	1160	2793	1786	1.58	5.48	776.0	25.8	160	Sl
700	51.7	266.0	38.2	1165	2793	1786	1.56	5.38	774.3	26.3	160	Sl
750	52.6	267.0	38.0	1170	2792	1787	1.54	5.29	772.6	26.7	160	Sl
800	53.4	268.1	37.9	1176	2791	1787	1.52	5.19	770.9	27.2	160	Sl
850	54.3	269.1	37.7	1181	2791	1788	5.15	10.02	769.2	27.7	110	Sl
900	55.1	270.0	37.6	1185	2790	1788	5.07	9.85	767.7	28.1	110	Sl
950	55.8	270.9	37.4	1190	2789	1789	5.00	9.69	766.2	28.5	110	Sl
1000	56.6	271.8	37.3	1194	2788	1789	4.93	9.54	764.7	29.0	110	Sl
1050	57.4	272.7	37.2	1199	2788	1790	4.86	9.39	763.2	29.4	110	Sl
1100	58.2	273.6	37.1	1203	2787	1790	4.80	9.24	761.7	29.8	110	Sl
1150	60.1	275.7	3.2	1214	2785	1265	.95	1.26	758.1	30.9	110	Bu
1200	63.2	278.9	2.2	1231	2782	1266	.83	1.10	752.5	32.6	110	Bu
1250	66.7	282.6	1.0	1250	2777	1266	.71	.93	745.9	34.6	110	Bu
1300	70.6	285.6	0	1267	0	1267	.62	.00	740.4	.0	110	1p
1350	74.3	285.8	0	1267	0	1267	.62	.00	740.8	.0	110	1p

1400	77.9	285.9	.0	1268	0	1268	.62	.00	741.2	.0	110	1p
1450	81.6	286.1	.0	1268	0	1268	.62	.00	741.6	.0	110	1p
1500	85.2	286.2	.0	1269	0	1269	.62	.00	741.9	.0	110	1p
1550	88.8	286.3	.0	1269	0	1269	.62	.00	742.3	.0	110	1p
1600	92.5	287.8	.0	1276	0	1276	.36	.00	740.1	.0	110	1p
1650	96.1	287.9	.0	1277	0	1277	.36	.00	740.4	.0	110	1p
1700	99.8	288.1	.0	1277	0	1277	.36	.00	740.8	.0	110	1p
1750	103.4	288.2	.0	1278	0	1278	.36	.00	741.2	.0	110	1p
1800	107.0	288.3	.0	1278	0	1278	.36	.00	741.6	.0	110	1p
1850	110.7	288.5	.0	1279	0	1279	.36	.00	741.9	.0	110	1p
1900	114.3	288.6	.0	1279	0	1279	.36	.00	742.3	.0	110	1p
1950	118.0	288.7	.0	1280	0	1280	.36	.00	742.7	.0	110	1p
2000	121.6	288.9	.0	1280	0	1280	.36	.00	743.0	.0	110	1p

Well RN-18

Wellhead pressure (bar-a)	:	31.58
Wellhead temperature (°C)	:	236.70
Wellhead dryness (%)	:	26.29
Wellhead enthalpy (kJ/kg)	:	1489.96
Wellhead total flow (kg/s)	:	51.03

Feedzone	Depth (m)	Flow (kg/s)	Enthalpy (kJ/kg)	Resv.Press (bar-a)	Saturation (m3/m3)	Prod.Index (kg/s/m3)
1	800.0	.09	1520.00	48.90	.00	.100E-12
2	1800.0	50.94	1220.00	119.00	.00	.130E-10

Depth (m)	Press (bar-a)	Temp (°C)	Dryness (%)	Hw ----(kJ/kg)---	Hs	Ht	Vw ----(m/s)----	Vs	Dw --(kg/m3)--	Ds	Rad (mm)	Reg
0	31.6	236.7	26.3	1022	2802	1490	5.66	11.74	818.2	15.8	160	Sl
50	32.3	237.9	26.1	1028	2802	1490	5.52	11.43	816.5	16.2	160	Sl
100	33.0	239.2	25.9	1034	2802	1491	5.39	11.13	814.8	16.5	160	Sl
150	33.7	240.4	25.6	1039	2802	1491	5.26	10.83	813.1	16.9	160	Sl
200	34.4	241.6	25.4	1045	2802	1492	5.14	10.55	811.3	17.2	160	Sl
250	35.2	242.8	25.2	1051	2802	1492	5.02	10.27	809.6	17.6	160	Sl
300	35.9	244.0	25.0	1057	2802	1493	4.90	10.01	807.9	18.0	160	Sl
350	36.7	245.3	24.8	1063	2802	1493	4.79	9.75	806.1	18.4	160	Sl
400	37.5	246.5	24.5	1069	2801	1494	4.68	9.50	804.4	18.8	160	Sl
450	38.2	247.7	24.3	1075	2801	1494	4.57	9.25	802.6	19.2	160	Sl
500	39.0	248.9	24.1	1080	2801	1495	4.46	9.01	800.8	19.6	160	Sl
550	39.8	250.1	23.9	1086	2800	1495	4.36	8.78	799.0	20.0	160	Sl
600	40.7	251.3	23.6	1092	2800	1496	4.26	8.55	797.2	20.4	160	Sl
650	41.5	252.5	23.4	1098	2800	1496	4.16	8.33	795.4	20.9	160	Sl
700	42.4	253.8	23.2	1104	2799	1497	4.07	8.12	793.5	21.3	160	Sl
750	43.2	255.0	22.9	1110	2799	1497	3.97	7.91	791.7	21.8	160	Sl
800	44.4	256.6	22.6	1118	2798	1498	11.11	15.38	789.3	22.4	110	Sl
800	44.4	256.6	5.5	1118	2798	1210	4.10	5.40	789.3	22.4	110	Bu
850	46.4	259.2	4.8	1131	2797	1211	3.71	4.87	785.1	23.4	110	Sl
900	48.5	262.1	4.0	1145	2795	1211	3.31	4.33	780.6	24.6	110	Sl
950	51.0	265.2	3.1	1161	2793	1212	2.91	3.79	775.6	25.9	110	Sl
1000	54.0	268.7	2.1	1179	2791	1212	2.49	3.22	769.9	27.5	110	Sl
1050	57.5	272.8	.8	1200	2788	1213	2.03	2.62	763.0	29.5	110	Sl
1100	61.3	275.5	.0	1213	0	1213	1.77	.00	758.7	.0	110	1p
1150	65.0	275.6	.0	1214	0	1214	1.77	.00	759.1	.0	110	1p
1200	68.8	275.7	.0	1214	0	1214	1.76	.00	759.4	.0	110	1p
1250	72.5	275.8	.0	1215	0	1215	1.76	.00	759.8	.0	110	1p
1300	76.3	276.0	.0	1215	0	1215	1.76	.00	760.1	.0	110	1p
1350	80.1	276.1	.0	1216	0	1216	1.76	.00	760.5	.0	110	1p
1400	83.8	276.2	.0	1216	0	1216	1.76	.00	760.8	.0	110	1p
1450	87.6	276.3	.0	1217	0	1217	1.76	.00	761.2	.0	110	1p

1500	91.4	276.5	.0	1217	0	1217	1.76	.00	761.5	.0	110	1p
1550	95.2	276.6	.0	1218	0	1218	1.76	.00	761.9	.0	110	1p
1600	98.9	276.7	.0	1218	0	1218	1.76	.00	762.2	.0	110	1p
1650	102.7	276.8	.0	1219	0	1219	1.76	.00	762.6	.0	110	1p
1700	106.5	277.0	.0	1219	0	1219	1.76	.00	762.9	.0	110	1p
1750	110.3	277.1	.0	1220	0	1220	1.76	.00	763.3	.0	110	1p
1800	114.1	277.2	.0	1220	0	1220	1.75	.00	763.6	.0	110	1p

Well RN-23

Wellhead pressure (bar-a)	:	46.04
Wellhead temperature (°C)	:	258.81
Wellhead dryness (%)	:	19.34
Wellhead enthalpy (kJ/kg)	:	1451.64
Wellhead total flow (kg/s)	:	154.84

Feedzone	Depth (m)	Flow (kg/s)	Enthalpy (kJ/kg)	Resv.Press (bar-a)	Saturation (m3/m3)	Prod.Index (kg/s/m3)
1	750.0	30.76	1470.00	67.90	.00	.300E-10
2	1200.0	38.07	1280.00	97.20	.00	.100E-10
3	1730.0	86.01	1370.00	134.00	.00	.300E-10

Depth (m)	Press (bar-a)	Temp (°C)	Dryness (%)	Hw	Hs	Ht	Vw	Vs	Dw	Ds	Rad (mm)	Reg
				----(kJ/kg)---			----(m/s)----		--(kg/m3)--			
0	46.0	258.8	19.3	1129	2797	1452	14.21	18.60	785.8	23.3	160	Sl
50	47.1	260.2	19.0	1136	2796	1452	13.77	18.00	783.6	23.8	160	Sl
100	48.1	261.5	18.8	1143	2796	1453	13.35	17.43	781.5	24.4	160	Sl
150	49.2	262.9	18.5	1149	2795	1453	12.95	16.88	779.3	24.9	160	Sl
200	50.3	264.3	18.2	1156	2794	1454	12.56	16.34	777.2	25.5	160	Sl
250	51.4	265.6	17.9	1163	2793	1454	12.19	15.83	775.0	26.1	160	Sl
300	52.5	266.9	17.6	1170	2792	1455	11.82	15.33	772.8	26.7	160	Sl
350	53.6	268.3	17.3	1177	2791	1455	11.47	14.85	770.6	27.3	160	Sl
400	54.7	269.6	16.9	1183	2790	1456	11.12	14.38	768.4	27.9	160	Sl
450	55.9	271.0	16.6	1190	2789	1456	10.79	13.92	766.2	28.6	160	Sl
500	57.1	272.3	16.3	1197	2788	1457	10.46	13.48	763.9	29.2	160	Sl
550	58.3	273.6	16.0	1204	2787	1457	10.14	13.05	761.6	29.9	160	Sl
600	59.5	275.0	15.7	1211	2786	1458	9.83	12.63	759.3	30.5	160	Sl
650	60.7	276.3	15.3	1218	2784	1458	9.53	12.22	757.0	31.2	160	Sl
700	62.0	277.7	15.0	1225	2783	1459	9.24	11.82	754.6	31.9	160	Sl
750	64.8	280.6	14.2	1240	2780	1459	20.27	22.46	749.5	33.5	110	Sl
750	64.8	280.6	6.1	1240	2780	1334	9.41	10.57	749.5	33.5	110	Bu
800	67.1	282.9	5.4	1252	2777	1335	8.68	9.73	745.3	34.8	110	Sl
850	69.5	285.3	4.7	1265	2774	1335	7.96	8.92	740.9	36.2	110	Sl
900	72.1	287.8	3.9	1278	2771	1336	7.26	8.11	736.3	37.8	110	Sl
950	74.9	290.4	3.0	1292	2767	1336	6.55	7.31	731.3	39.4	110	Sl
1000	78.0	293.2	2.0	1307	2763	1337	5.85	6.51	725.9	41.3	110	Sl
1050	81.4	296.2	1.0	1324	2758	1337	5.21	5.21	720.0	43.4	110	Bu
1100	85.0	298.7	.0	1338	0	1338	4.57	.00	715.0	.0	110	1p
1150	88.8	298.9	.0	1338	0	1338	4.56	.00	715.4	.0	110	1p
1200	92.5	299.0	.0	1339	0	1339	4.56	.00	715.9	.0	110	1p
1200	92.5	303.6	.0	1365	0	1365	3.21	.00	705.3	.0	110	1p
1250	96.1	303.7	.0	1365	0	1365	3.21	.00	705.7	.0	110	1p
1300	99.7	303.9	.0	1366	0	1366	3.20	.00	706.2	.0	110	1p
1350	103.3	304.1	.0	1366	0	1366	3.20	.00	706.7	.0	110	1p

1400	106.8	304.2	.0	1367	0	1367	3.20	.00	707.1	.0	110	1p
1450	110.4	304.4	.0	1367	0	1367	3.20	.00	707.6	.0	110	1p
1500	114.0	304.6	.0	1368	0	1368	3.20	.00	708.0	.0	110	1p
1550	117.6	304.7	.0	1368	0	1368	3.19	.00	708.5	.0	110	1p
1600	121.2	304.9	.0	1369	0	1369	3.19	.00	708.9	.0	110	1p
1650	124.8	305.0	.0	1369	0	1369	3.19	.00	709.3	.0	110	1p
1700	128.4	305.2	.0	1370	0	1370	3.19	.00	709.8	.0	110	1p

A.6 Monte Carlo simulation

Table A.3: Monte Carlo input data for Reykjanes geothermal field in Iceland.

Parameters	Units	Most likely	Probability distribution		
			Type of distribution	Minimum	Maximum
Area for case I	km^2	2	Triangular	1	2
Area for case II	km^2	2	Triangular	1	11
Thickness for case I	m	2000	Triangular	800	2500
Thickness for case II	m	2500	Triangular	1000	3000
Rock density	kg/m^3	3000	Constant		
Rock specific heat	kJ/(kg°C)	0.84	Constant		
Porosity	%	10	Constant		
Temperature for case I & II	°C	300	Triangular	280	340
Rejection temperature	°C	40	Constant		
Fluid density for case I	kg/m^3	740	f (temp., salinity)		
Fluid density for case II	kg/m^3	724	f (temp., salinity)		
Fluid specific heat for case I	kJ/(kg °C)	5.5	f (temp.)		
Fluid specific heat for case II	kJ/(kg °C)	5.75	f(temp.)		
Recovery factor for case I	%	20	Triangular	10	25
Recovery factor for case II	%	10	Triangular	5	20
Conversion efficiency	%	14	Triangular	13	15
Plant life	Years	30,50	Constant		
Load factor	%	95	Constant		

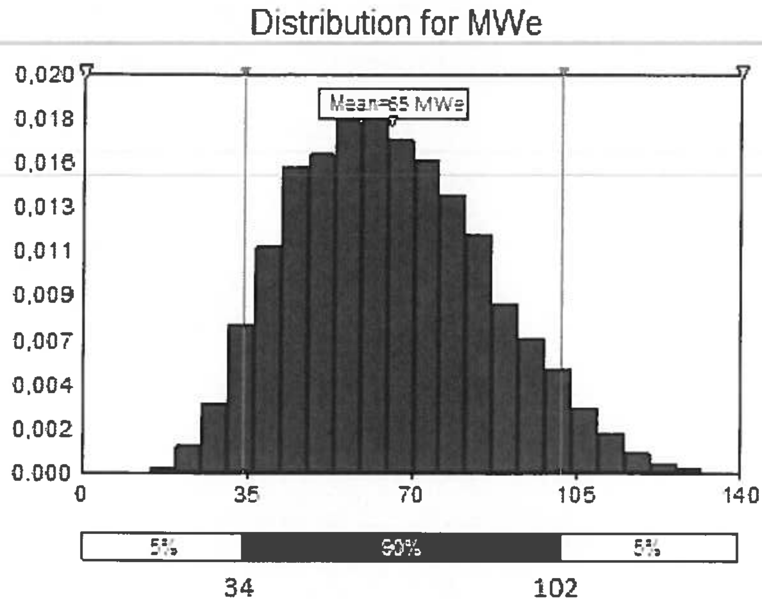


Figure A.12: Frequency distribution for electric power generation for Reykjanes geothermal field case I, 30 years.

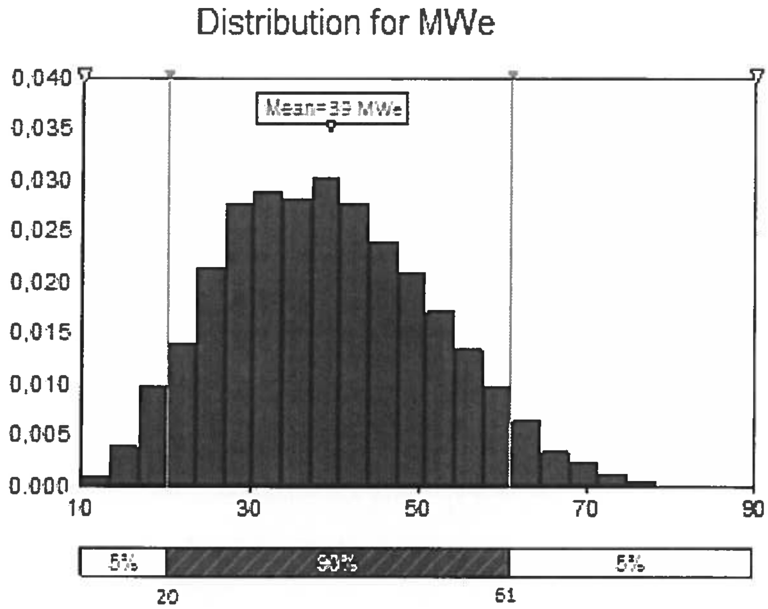


Figure A.13: Frequency distribution for electric power generation for Reykjanes geothermal field case I, 50 years.

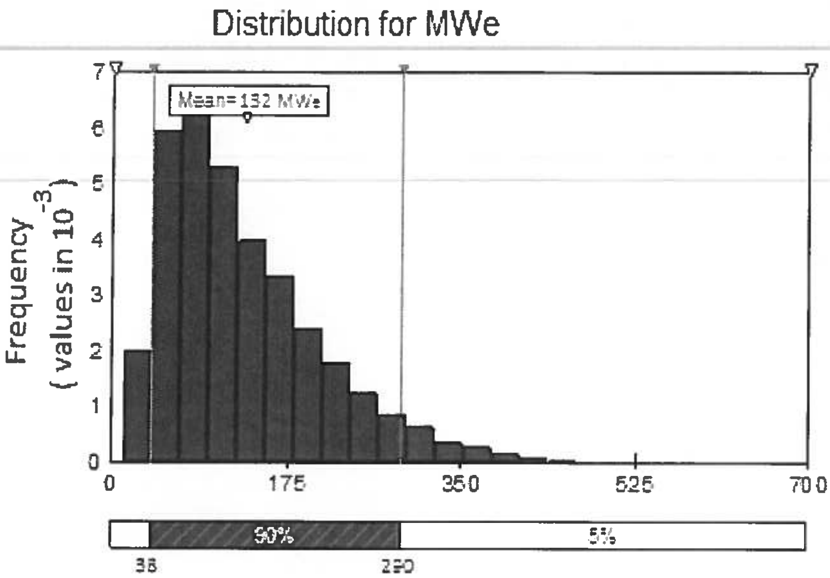


Figure A.14: Frequency distribution for electric power generation for Reykjanes geothermal field case II, 30 years.

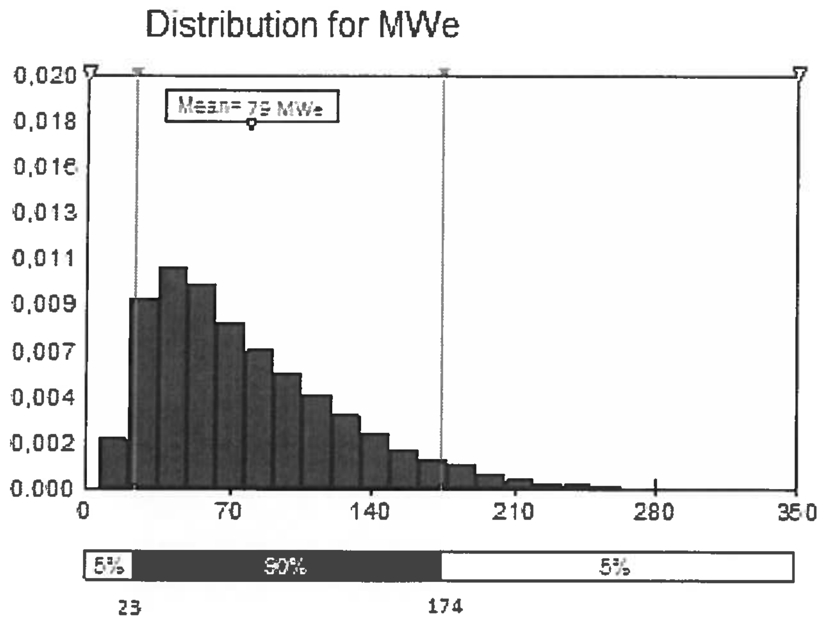


Figure A.15: Frequency distribution for electric power generation for Reykjanes geothermal field case II, 50 years.

ATTACHMENT H – OPERATING DATA

1. ACTUAL OPERATING DATA

The operational data for the five existing injection wells included under this permit are provided in this section, based on: (1) actual operation, and (2) the system design. Figures H-1, H-2, and H-3 graphically depict the actual injection rate and wellbore pressure as a function of time for wells KS-1A, KS-3, KS-11, KS-13, and KS-15, respectively.

2. DESIGN OPERATION DATA

The injection pressure in each well must be maintained at a value less than the fracture pressure of the formation at the shoe of the last cemented casing string. In two of the four existing injection wells covered under this permit application, this is the 9 5/8-inch casing, which is set at a depth of about 4,000 feet. In the three newer well KS-11, KS-13, and KS-15 this is an 11 3/4-inch casing, which is set at 5000, 4850, and 3900 feet respectively.

The rate at which geothermal fluid can be injected into the injection well is limited by the fracture pressure. While the fracture pressure is constant, the make-up of the geothermal fluid is expected to gradually change as a function of changes in the geothermal resource. To assure that the fracture pressure in the geothermal reservoir is not exceeded, PGV monitors the wellhead pressure on each injection well. PGV proposes that the permit conditions established in the UIC Permit set maximum wellhead pressures which cannot be exceeded during operation of the injection wells. By establishing these permit conditions, the reservoir will be protected.

Table H-1 lists the maximum injection pressure that meets the above criterion for each of PGV’s injection wells. The development of these proposed pressure limits in Table H-1 are based on results of formation pressure tests run since PGV’s Casing Monitoring Program went into effect (now referred to as the Program for Mechanical Integrity Testing and Monitoring of Injection Wells, Attachment P, Appendix B). For wells drilled prior to this, including KS-1A and KS-3, the drilling histories do not indicate that formation pressure tests were done. As noted in the table, test results from KS-4 are applied to KS-3 and KS-1A, respectively, but with larger than normal factors of safety. Application of KS-4 results to KS-1A and KS-3 is justified by the following:

- Comparable lithology from well to well;
- Uniformity of test results from KS-4 and KS-9 (the wells closest to KS-3 and KS-1A); and
- The conservative manner in which the tests were done.

With respect to the latter, none of the formation pressure tests was carried to the point of formation breakdown. Instead, in each test run during the drilling of KS-4 and KS-9, the formation at the shoe of the 9-inch casing was tested with mud in the hole to gradients of 0.65 and 0.68 psi/ft., respectively, with no measurable leakoff. For purposes of determining the maximum allowable injection pressure, the test gradient in KS-4 is taken as the incipient fracture pressure, although the actual fracture pressure would be higher. Wellhead pressures corresponding to this "fracture pressure" value are calculated using the density of 10,000 ppm TDS water at 80ºF and neglecting flowing pressure losses in the hangdown liner and wellbore. Both of these are conservative assumptions with respect to avoiding formation breakdown.

The formation pressure test procedure is described below:

1. Perform formation pressure test or "leakoff test" after drilling out below the shoe of the deepest cemented casing or liner. Test with the wellbore full of mud or water.
2. Measure density of mud or water sample taken from circulation returns.
3. Close Blowout Preventer (BOP) on drillpipe.
4. Increase wellbore pressure in stages of equal fluid volume, pausing after each stage to observe the pressure at the surface. For example, pump 5 gallons of fluid, stop pumping momentarily, observe the pressure on the standpipe or at the wellhead, and repeat for each stage, keeping the fluid volume per stage as near constant as possible. As a general guideline, the fluid volume per stage should be selected to give a pressure increase of 100 psi or less.
5. Following the procedure in Step 4, the pressure increase for each stage will be approximately equal until the fracture pressure is reached. At fracture pressure, a minute leakoff will occur, and the incremental pressure rise for that stage will be noticeably less. The test will be terminated at this point. At PGV's discretion, the test may be terminated at a lower pressure.
6. Whether or not the test is carried to the point of leakoff , the "fracture pressure" for purposes of determining the maximum allowable injection pressure is considered to be the pressure at the last stage for which there was no indication of fracture initiation.

It is intended that this reservoir testing program be used to determine the effective fracture pressure in future injection wells drilled in the Area of Review, as described on the UIC Application Form, Box IX.

The wellhead pressure is determined through a calculation. This calculation procedure is described below:

<u>Calculate test pressure at casing shoe:</u>

$$P_{T\text{-}shoe} = P_{T\text{-}wh} + 0.052 * \rho_{mud} * TVD_{KB}$$

Calculate injection wellhead pressure corresponding to $P_{T\text{-shoe}}$:

$$P_{T\text{-wh}} = P_{shoe} - 0.052 * \rho_{inj} * TVD_{GL}$$

Calculate maximum safe injection wellhead pressure:

$$P_{I\text{-wh}} = 0.8 * P_{T\text{-wh}}$$

Nomenclature:

P = pressure (psig)
TVD = true vertical depth
ρ = fluid density (lb_m/gal)

Subscripts:

GL = ground level (reference for depth measurement)
inj = injectate (assumed density = 8.359 lb_m/gal)
KB = rig Kelly bushing (reference for depth measurement)
mud = drilling mud (or water) in the wellbore during formation pressure test
shoe = at shoe of casing or liner
T = formation pressure test
wh = wellhead

The maximum wellhead injection pressures, shown in Table H-1, for the three injection wells have been calculated with the procedure described above. It is proposed that these wellhead injection pressures be established as permit conditions. Additionally, the calculated injection capacity corresponding to the maximum wellhead injection pressure are provided in Table H-1 for information only. As previously stated, it is proposed that these values not be established as permit conditions. The calculation procedure for determining the maximum wellhead pressure, shown above, is proposed to be used to determine the wellhead pressure limit and establish permit conditions for future injection wells drilled in the Area of Review as described in the UIC Application Form, Box IX.

3. ANNULUS FLUIDS

The annulus fluid for the injection wells is nitrogen gas. The nitrogen gas is used to isolate the underground drinking water source from injectate and to monitor for potential casing failures as described in the Program for Mechanical Integrity Testing and Monitoring of Injection Wells, included in Attachment P – Monitoring Program.

4. INJECTATE SAMPLING RESULTS

The most recent chemical and physical analysis results for Type I, Type III, and Type IV sampling of the injectate is provided in Attachment H-1. These injectate samples were taken from geothermal fluids being produced at the PGV site during the months of May and July 2004. The samples were taken in accordance with the requirements of PGV's current UIC Permit No. UH-1529 with the State of Hawaii.

	KS-1A Pressure					KS-1A Temperature			
DATE	Hrs on Inj	Peak A	Peak B	Peak C	Peak D	Peak A	Peak B	Peak C	Peak D
04/01/18	24	193		150		200		195	
04/02/18	24	160		155		195		200	
04/03/18	24	120		140		190		190	
04/04/18	24	130		140		190		190	
04/05/18	24	150		180		190		195	
04/06/18	24	185		180		195		195	
04/07/18	24	160		170		195		195	
04/08/18	24	160		160		195		194	
04/09/18	24	175		170		190		200	
04/10/18	24	175		175		195		195	
04/11/18	24	152		145		198		198	
04/12/18	24	150		150		195		198	
04/13/18	13.3	0		155		120		195	
04/14/18	24	160		185		195		195	
04/15/18	21.8	100		165		162		195	
04/16/18	24	170		160		200		188	
04/17/18	24	180		120		185		194	
04/18/18	24	115		130		198		197	
04/19/18	24	125		135		189		189	
04/20/18	24	140		140		195		190	
04/21/18	24	135		130		195		192	
04/22/18	24	120		140		190		190	
04/23/18	24	145		170		190		195	
04/24/18	24	170		180		195		195	
04/25/18	24	170		172		190		193	
04/26/18	24	175		170		198		195	
04/27/18	24	180		125		195		190	
04/28/18	24	135		130		195		192	
04/29/18	24	170		185		195		193	
04/30/18	24	200		197		200		195	

KS-1A Annulus Pressure				KS-3 Pressure					KS-3 Temperatu
Peak A	Peak B	Peak C	Peak D	Hrs on Inj	Peak A	Peak B	Peak C	Peak D	Peak A
62		77		24	180		175		174
75		73		24	175		175		170
71		69		24	150		150		170
68		66		24	155		155		173
64		63		24	165		185		165
62		74		24	182		195		173
71		71		24	182		190		160
68		67		24	185		185		168
65		75		24	170		185		160
74		72		24	185		185		170
69		69		24	160		170		172
66		65		24	170		172		175
55		63		24	165		180		165
61		71		24	183		195		170
60		68		24	110		180		150
66		64		24	188		125		170
63		62		24	170		140		165
60		75		24	135		145		165
72		71		24	145		150		170
69		68		24	150		155		170
66		65		24	140		150		162
63		62		24	150		150		165
60		61		24	150		195		170
67		66		24	185		200		165
64		74		24	190		200		170
72		72		24	190		190		165
70		68		24	200		146		170
66		65		24	150		150		170
64		63		24	195		205		170
73		72		24	205		203		170

			KS-3				KS-15		
re			Annulus Pressure				Pressure		
Peak B	Peak C	Peak D	Peak A	Peak B	Peak C	Peak D	Hrs on Inj	Peak A	Peak B
	169		66		66		24	0	
	170		65		65		24	0	
	165		64		63		24	0	
	170		63		62		24	0	
	170		61		61		24	0	
	172		60		60		24	0	
	175		58		59		24	0	
	170		57		57		24	0	
	173		56		73		24	0	
	170		71		70		24	0	
	170		70		68		24	0	
	175		67		66		24	0	
	175		64		65		24	0	
	170		63		63		24	0	
	174		60		60		24	0	
	165		59		56		24	0	
	175		57		56		24	0	
	172		55		71		24	0	
	150		69		69		24	0	
	170		67		66		24	0	
	170		65		65		24	0	
	165		63		62		24	0	
	172		61		61		24	0	
	173		59		59		24	0	
	175		57		70		24	0	
	175		68		68		24	0	
	172		66		65		24	0	
	172		64		63		24	0	
	170		61		61		24	0	
	168		60		59		24	0	

		KS-15 Temperature				KS-15 Annulus Pressure			
Peak C	Peak D	Peak A	Peak B	Peak C	Peak D	Peak A	Peak B	Peak C	Peak D
0		155		138		11		12	
0		134		110		12		12	
0		135		122		11		11	
0		115		105		11		11	
0		100		112		11		11	
0		125		130		11		12	
0		135		130		11		11	
0		125		125		11		11	
0		115		112		11		11	
0		0		105		11		11	
0		135		138		11		12	
0		125		125		11		12	
0		125		130		10		10	
0		100		120		100		100	
0		75		100		100		100	
0		130		125		100		100	
0		125		122		10		0	
0		135		140		0		13	
0		125		95		11		11	
0		90		80		11		11	
0		100		100		11		11	
0		100		100		11		11	
0		100		100		11		11	
0		115		125		11		11	
0		120		122		11		11	
0		125		95		11		11	
0		130		140		11		14	
0		140		138		14		14	
0		100		110		11		11	
0		105		120		11		11	

KS-11INJ Pressure					KS-11INJ Temperature				KS-11INJ Annulus Pr
Hrs on Inj	Peak A	Peak B	Peak C	Peak D	Peak A	Peak B	Peak C	Peak D	Peak A
24	172		150		192		190		73
24	165		165		190		190		72
24	145		150		192		180		70
24	150		150		192		180		70
24	155		175		180		180		69
24	160		185		180		180		70
24	160		180		175		180		68
24	170		170		175		175		68
24	165		185		172		178		67
24	170		170		165		165		66
24	151		150		170		170		69
24	165		162		170		169		72
24	155		170		165		170		72
15	0		0		165		75		66
0	0		0		80		75		36
0	0		0		195		0		15
0	0		0		85		102		6
0	0		0		85		75		1
0	0		0		80		80		0
0	0		0		80		75		0
0	0		0		80		80		0
0	0		0		80		75		0
0	0		0		0		75		0
0	0		0		0		75		0
0	0		0		75		0		0
0	0		0		75		75		2.7
0	0		0		75		75		2.7
0	0		0		75		75		0
0	0		0		75		75		0
0	0		0		75		75		0

essure			KS-13 Pressure					KS-13 Temperature	
Peak B	Peak C	Peak D	Hrs on Inj	Peak A	Peak B	Peak C	Peak D	Peak A	Peak B
	73		24	182		170		192	
	72		24	170		170		188	
	71		24	90		95		185	
	70		24	100		110		190	
	70		24	100		180		188	
	70		24	180		190		192	
	69		24	160		180		188	
	68		24	175		175		188	
	67		24	165		180		190	
	75		24	180		180		190	
	73		24	170		160		192	
	73		24	150		160		190	
	72		24	135		175		178	
	49		24	170		190		190	
	26		24	52		180		172	
	10		24	180		160		192	
	2		24	165		148		183	
	0		24	125		138		188	
	0		24	125		115		185	
	0		24	140		135		188	
	0		24	120		130		184	
	0		24	120		130		184	
	0		24	120		185		187	
	0		24	180		190		184	
	0		24	170		185		190	
	2.6		24	180		175		188	
	2		24	185		145		190	
	0		24	150		140		188	
	0		24	180		188		188	
	0		24	200		200		190	

KS-13
Annulus Pressure

Peak C	Peak D	Peak A	Peak B	Peak C	Peak D
189		61		61	
190		61		61	
187		59		59	
188		59		59	
190		58		59	
190		59		59	
190		58		58	
190		58		58	
191		57		73	
188		72		72	
189		71		71	
190		70		70	
188		68		69	
195		69		69	
190		66		68	
184		68		67	
190		67		66	
199		66		66	
185		65		65	
185		65		64	
186		63		64	
183		63		63	
190		62		63	
190		63		63	
192		62		62	
185		61		61	
189		61		61	
187		60		60	
192		60		60	
189		60		60	

TEST PARAMETERS FOR TYPE I SAMPLE

Parameter	Method
Arsenic (As)	6010/206
Barium (Ba)	6010/208
Boron (B)	200
Cadmium (Cd)	6010/213
Calcium (Ca)	6010/215
Copper (Cu)	6010/220
Chromium (Cr)	6010/218
Iron (Fe)	6010/236
Lead (Pb)	6010/239
Lithium (Li)	6010/7430
Magnesium (Mg)	6010/242
Manganese (Mn)	6010/243
Mercury (Hg)	7470/245
Nickel (Ni)	6010/200
Potassium (K)	6010/258
Silver (Ag)	6010/272
Sodium (Na)	6010/273
Vanadium (V)	6010/286
Zinc (Zn)	6010/289
Bromide	320
Bicarbonate (HCO3)	310
Carbonate (CO3)	310
Chloride	325
Fluoride	340
Nitrate (NO3)	352
Silica (SiO2)	370
Sulfate (SO4)	375
Total Sulfur (S)	Various
Total Alkalinity	310
Total Dissolved Solids (TDS)	160.1
Total Suspended Solids (TSS)	160.2
Oil and Grease	413 or 1664
Conductivity	120

Gas Parameter
Ammonia (NH3)
Argon (Ar)
Carbon Dioxide (CO2)
Hydrogen (H2)
Hydrogen Sulfide (H2S)
Methane (CH4)
Nitrogen (N2)
Oxygen (O2)
Radon
N-Pentane

QUALITY CONTROL DATA

Samples Received: March 26, 2018

Requested By: Ronald Quesada
Puna Geothermal Venture
P.O. Box 30
Pahoa, HI 96778

Analyte	**Precision (%RSD)**	**External Standard (% Recovery)**	**Sample Spike (% Recovery)**
Carbon Dioxide	0.6	97.0	104.3
Hydrogen Sulfide	1.4	102.8	99.7
Ammonia	0.0	101.8	107.7
Nitrogen	0.4	98.9	NA
Methane	0.7	100.5	NA
Hydrogen	0.5	99.9	NA

Precision: Percent Relative Standard Deviation of replicate sample analyses.

External Standard: Percent Recovery of an independent audit standard analyzed against calibration standards (measured/known x 100).

Sample Spike: Percent Recovery of a known quantity of standard added to sample (measured/theoretical x 100).

N/A: Not Applicable.

Paula Bosserman, Ph.D.
Lab and Quality Manager

Distribution:

Descriptor: PGV Monthly Type I Injectate
Sampling Date, Time: 3-19-18 19:31
Sampling Location: NC Gas line prior to mixing with injectate fluid flow
Sampling Method: ASTM E 1675-95
Sampled by: P. Fernandez, S. Magnuson

Lab Number: 22374-1

Total Weight of Condensate (grams): 1
Initial Headspace Pressure (psia @ STP): 16.08

Gas	**Result**	Reporting Units	Reference Method	Analysis Date	Analyst Name
Ammonia	<1.78E-03	Mole%, Dry Gas	Ste. Mth. 4500-NH3 C	4/9/2018	Bianca Ramirez
Argon	3.78E-01	Mole%, Dry Gas	GC / TCD	4/4/2018	Lili Van Dera
Carbon Dioxide	3.78E+01	Mole%, Dry Gas	Acid Evolution, IR	4/11/2018	Bianca Ramirez
Hydrogen	2.57E+01	Mole%, Dry Gas	GC / TCD	4/4/2018	Lili Van Dera
Hydrogen Sulfide	1.57E+01	Mole%, Dry Gas	EPA 376.1	4/6/2018	Bianca Ramirez
Methane	5.66E-01	Mole%, Dry Gas	GC / TCD	4/4/2018	Lili Van Dera
Nitrogen	1.97E+01	Mole%, Dry Gas	GC / TCD	4/4/2018	Lili Van Dera
Oxygen	1.66E-01	Mole%, Dry Gas	GC / TCD	4/4/2018	Lili Van Dera
Radon-222	8.87E+03	pCi/L Dry Gas, STP	Scintillation Counter	3/26/2018	Joanna Collier
n-Pentane	1.20E-02	Mole%, Dry Gas	GC / FID	3/29/2018	Lili Van Dera

IR = infrared analysis
GC/FID = gas chromatography, flame ionization detection
GC/TCD = gas chromatography, thermal conductivity detection
pCi/L = picoCurie per liter

THERMOCHEM®
Empowering Energy Industries since 1985

22383-1 April 18, 2018

Ron Quesada
Puna Geothermal Venture
P.O. Box 30
Pahoa, HI 96778

Report of Analysis

Lab Number:	22383 - 1
Descriptor:	PGV Monthly Type I Injectate
Sampling Date, Time:	3-19-18 20:38 - 21:58
Sampling Location:	Injection line sampling port between common header and active injection well
Sampling Method:	ASTM E 1675-95
Sampled by:	P. Fernandez, S. Magnuson
Field Data:	NA

Analyte	Result	Reporting Units	Reference Method	Analysis Date	Analyst Name
Arsenic	0.154	mg/kg	EPA 6010B	3/29/2018	Joanna Collier
Barium	3.10	mg/kg	EPA 6010B	3/29/2018	Joanna Collier
Boron	3.80	mg/kg	EPA 6010B	3/29/2018	Joanna Collier
Cadmium	<0.006	mg/kg	EPA 6010B	4/16/2018	Sheri Cruz [2]
Calcium	147	mg/kg	EPA 6010B	3/29/2018	Joanna Collier
Copper	<0.2	mg/kg	EPA 6010B	4/16/2018	Sheri Cruz [2]
Chromium	<0.04	mg/kg	EPA 6010B	4/16/2018	Sheri Cruz [2]
Iron	0.121	mg/kg	EPA 6010B	3/29/2018	Joanna Collier
Lead	<0.03	mg/kg	EPA 6010B	4/16/2018	Sheri Cruz [2]
Lithium	1.67	mg/kg	Std. Mth. 3500-Li B	3/29/2018	Joanna Collier
Magnesium	0.073	mg/kg	EPA 6010B	3/29/2018	Joanna Collier
Manganese	0.261	mg/kg	EPA 6010B	3/29/2018	Joanna Collier
Mercury	<0.002	mg/kg	EPA 7470A	4/13/2018	Sheri Cruz [2]
Nickel	<0.03	mg/kg	EPA 6010B	4/16/2018	Sheri Cruz [2]
Potassium	815	mg/kg	EPA 258.1	3/28/2018	Joanna Collier
Silver	<0.1	mg/kg	EPA 6010B	4/16/2018	Sheri Cruz [2]
Sodium	4290	mg/kg	EPA 273.1	3/28/2018	Joanna Collier
Vanadium	<0.08	mg/kg	EPA 6010B	4/16/2018	Sheri Cruz [2]
Zinc	<0.1	mg/kg	EPA 6010B	4/16/2018	Sheri Cruz [2]
Bromide	26.0	mg/kg	EPA 300	3/30/2018	Kristy Stokes
Bicarbonate Alkalinity (as HCO3-)	<2	mg/kg	Std. Mth. 2320 B	3/30/2018	Bianca Ramirez
Carbonate Alkalinity (as CO3=)	<2	mg/kg	Std. Mth. 2320 B	3/30/2018	Bianca Ramirez
Chloride	7750	mg/kg	EPA 300	3/30/2018	Kristy Stokes
Fluoride	0.238	mg/kg	EPA 300	3/30/2018	Kristy Stokes
Nitrate	<1	mg/kg	EPA 300	3/30/2018	Kristy Stokes
Silica	603	mg/kg	EPA 6010B	3/29/2018	Joanna Collier
Sulfate	18.5	mg/kg	EPA 300	3/30/2018	Kristy Stokes
Total Sulfur [1]	42.3	mg/kg as Sulfur	EPA 300, EPA 376.1	3/30/2018	Bianca Ramirez
Total Alkalinity (as HCO3-)	<2	mg/kg	Std. Mth. 2320 B	3/30/2018	Bianca Ramirez
Total Dissolved Solids	13900	mg/kg	Std. Mth. 2540 B	4/4/2018	Bianca Ramirez
Total Suspended Solids	9.91	mg/kg	Std. Mth. 2540 D	4/6/2018	Bianca Ramirez
Oil & Grease	<5	mg/L	EPA 1664	4/13/2018	Sheri Cruz [2]
Conductivity, umhos/cm	20800	umhos/cm	EPA 120.1	3/30/2018	Bianca Ramirez

[1] Total Sulfur is reported as the sum of S_2O_3, SO_4, and H_2S as S

[2] Project Manager, TestAmerica Laboratory, Seattle

Log No.
Client No.
Check-In Date
Job No.

Chain of Custody

Reference No.

Company Name	Contact Name	Department
PUNA GEOTHERMAL VENTURE	Ron Quesada	
Street Address 14-3860 KAPOHO PAHOA ROAD	**Telephone No.** (808) 965-2848	**Project**
City, State, Zip PAHOA, HI 96778	**Telefax No.** (808) 965-7254	

Lab No. (TCI Only)	Field Sample Number	Sample Date	Sample Time	Other Samples Description (as required for final report)	Temperature/Pressure/Volume (specify location/units)	Sample Type	Field Preservative	No. of Containers Volume
	180698	3/19/2018	20:44	Monthly Type I Injectate		Plastic	None	1 liter
	180700	3/19/2018	20:47	Monthly Type I Injectate		Plastic	None	1 liter
	180703	3/19/2018	20:38	Monthly Type I Injectate		Glass	5 ml 1+1 HCL	1 liter
	180696	3/19/2018	21:00	Monthly Type I Injectate		Plastic	15.30.00	500 ml
	180702	3/19/2018	20:53	Monthly Type I Injectate		Brown	25 ml $K_2CR_2O_2/HNO_2$	125 ml
	180704	3/19/2018	20:56	Monthly Type I Injectate		Plastic	100 ml 5% 8%	500 ml
	180701	3/19/2018	21:36	Type 1 Injectate sample	Filtered – 180705	Plastic	200 ml (.1) $NHNO_3$	200 ml
	Y0034	3/19/2018	19:31	NCG Sample		Gas Bomb	75-50-75	275 ml
	Y0014	3/19/2018	19:33	NCG Sample		Gas Bomb	75-50-75	275 ml
	180697	3/19/2018	21:43	Type 1 Injectate sample	Filtered – 180706	Plastic	None	1 liter
	180699	3/19/2018	21:58	Type 1 Injectate sample	Filtered – 180707	Plastic	None	1 liter

Relinquished By				Received By			
Name (Print)	Signature	Date	Time	Name (Print)	Signature	Date	Time
Paul Fernandez	Paul Fernandez	3/19/2018	22:55	Kaitlin Michalowicz	K	3/26/18	7:00
Stanley Magnuson	[signature]	3/19/2018	22:55				

Condition of Samples on Receipt:

EMAX
LABORATORIES, INC.
1835 W. 205th Street
Torrance, CA 90501
Tel: (310) 618-8889
Fax: (310) 618-0818

Date: 02-06-2018
EMAX Batch No.: 18A178

Attn: Ronald P. Quesada

Puna Geothermal Venture
14-3860 Kapoho-Pahoa Road
P.O. Box 30 Pahoa, HI. 96778

Subject: Laboratory Report
Project: PUNA GEOTHERMAL VENTURE

Enclosed is the Laboratory report for samples received on 01/17/18.
The data reported relate only to samples listed below :

Sample ID	Control #	Col Date	Matrix	Analysis
TYPE 3 & 4 INJECTATE	A178-01	01/15/18	WATER	IGNITABILITY
				SULFIDE REACTIVE
				REACTIVE CYANIDE
				METALS TCLP
				MERCURY TCLP
				SEMIVOLATILE ORGANICS TCLP
				VOLATILE ORGANICS TCLP
				VOLATILE ORGANICS BY GC/MS
				PH
TRIP BLANK	A178-02	01/15/18	WATER	VOLATILE ORGANICS BY GC/MS

The results are summarized on the following pages.

Please feel free to call if you have any questions concerning these results.

Sincerely yours,

Caspar J. Pang
Laboratory Director

EMAX certifies that results included in this report meets all NELAC & DOD requirements unless noted in the Case Narrative.

NELAP Accredited Certificate Number CA002912017-13
L-A-B Accredited DoD ELAP and ISO/IEC 17025 Certificate Number L2278 Testing
California ELAP Accredited Certificate Number 2672

CHAIN OF CUSTODY

EMAX Laboratories, Inc.
1835 W. 205th Street, Torrance, CA 90501
Tel # : 310-618-8889 FAX#: 310-618-0818
Email: info@emaxlabs.com

PO NUMBER:

SAMPLE STORAGE

EMAX CONTROL NO. 18A178

PROJECT CODE:

CLIENT Ronald P Quesada
PROJECT Puna Geothermal Venture
COORDINATOR Ronald P Quesada
TEL 808-965-2848 FAX 808-965-7254 EMAIL rquesada@ormat.com
SEND REPORT TO Ronald P Quesada
COMPANY Puna Geothermal Venture
ADDRESS 14-3860 Kapoho Pahoa Road, Pahoa, HI 96778
EMAX PM

MATRIX CODE	PRESERVATIVE CODE
DW=Drinking Water	IC = Ice
GW=Ground Water	HC = HCl
WW=Waste Water	HN=HNO3
SD=Solid Waste SL=Sludge	SH=NaO3
SS=Soil/ Sediment	ST=Na2S2O3
WP=Wipes PP=Pure Products	ZA=Zinc Acetate
AR=Air	HS=H2SO4
O=	

ANALYSIS REQUIRED: VOCs by 8260B; TCLP VOCs by 8260B; TCLP SVOCs by 8270C; TCLP Metals and Mercury; Reactive Cyanide and Sulfide; pH and Ignitability

TAT:
- ☐ Rush __24__hrs.
- ☐ Rush __48_hrs
- ☐ Rush_72_hrs
- ☐ 7 days
- ☐ 14 days
- ☐ 21 days

LAB	CLIENT SAMPLE ID	LOCATION	DATE	TIME	NO.	SIZE	TYPE	MATRIX CODE	QC	VOCs by 8260B (HC)	TCLP VOCs by 8260B (IC)	TCLP SVOCs by 8270C (IC)	TCLP Metals and Mercury (IC)	Reactive Cyanide and Sulfide (NaOH/Zn)	pH and Ignitability (IC)				COMMENTS
* 1	(1) Type 3 & 4 Injectate	Injection	1/16/2018	200	14	various	various	Water		x	x	x	x	x	x				
* 2	(2) Trip Blank		1/16/2018	200	3	40ml	Vials	Water		x									
* 3																			
* 4																			
* 5																			
* 6																			
* 7																			
* 8																			
* 9																			
10																			

Instructions Perform analysis in accordance with PGV UIC Permit Requirements for Type 3 & 4 Injectate Sampling.

Cooler #	Temp. (°C)	Sample #s
x	2.0	

SAMPLER Desi Sugioka and Paul Fernandez

COURIER/AIRBILL

RELINQUISHED BY	Date	Time	RECEIVED BY
	1/17/18	0944	Maribel Mata

SAMPLE RECEIPT FORM 1

Reference: EMAX-SM02 Rev.9
Form: SM02F1

Type of Delivery	Airbill / Tracking Number	
☑ Fedex ☐ UPS ☐ GSO ☐ Others	8085 3131 8955	ECN 18A178
☐ EMAX Courier ☐ Client Delivery		Recipient Isabel Mata
		Date 1/17/18 Time 0944

COC INSPECTION

☑ Client Name ☑ Client PM/FC ☑ Sampler Name ☑ Sampling Date/Time ☑ Sample ID ☑ Matrix
☑ Address ☑ Tel # / Fax # ☐ Courier Signature ☑ Analysis Required ☑ Preservative (if any) ☐ TAT
Safety Issues (if any) ☐ High concentrations expected ☐ From Superfund Site ☐ Rad screening required

Note:

PACKAGING INSPECTION

Container ☑ Cooler ☐ Box ☐ Other
Condition ☐ Custody Seal ☐ Intact ☐ Damaged
Packaging ☑ Bubble Pack ☐ Styrofoam ☐ Popcorn ☑ Sufficient ☐
Temperatures (Cool, ≤6 °C but not frozen) ☑ Cooler 1 2.0 °C ☐ Cooler 2 °C ☐ Cooler 3 °C ☐ Cooler 4 °C ☐ Cooler 5 °C
☐ Cooler 6 °C ☐ Cooler 7 °C ☐ Cooler 8 °C ☐ Cooler 9 °C ☐ Cooler 10 °C
Thermometer: A - S/N B - S/N 1505555322 C - S/N D S/N 1505556030

Comments: ☐ **Temperature is out of range. PM was informed IMMEDIATELY.**

Note:

DISCREPANCIES

LabSampleID	LabSampleContainerID	Code	ClientSample Label ID / Information	Corrective Action
1	1-11	D7	COC has 1/16/18 700	R8
~~2~~	~~12-14~~		label has 1/15/18 1115	
2	12-14	D22	lot # TB-004-01-16	R9
1,2	1-14	D1		R1
1,2	1-3, 12-14, 11	D16	pres. accordingly.	R2
1		D11	Received 11 containers	
1		D8	TCLP SVOC by 8270C *	
1		D3	B7003CNBS	
			101617-3	
			00069255	

4 1/18/18 ym

☐ pH holding time requirement for water samples is 15 mins. Water samples for pH analysis are received beyond 15 minutes from sampling time.

NOTES/OBSERVATIONS: Received one 500mL poly bottle for TCLP Metals and Mercury and pH and Ignitability.
* Received 1/19/18
1/22/18. Samples #1 (1-3, 7-9) → D14 R4 LP 1/22/18

☐ **Continue to next page.**

LEGEND:

Code	Description- Sample Management	Code	Description-Sample Management	Code	Description-Sample Management
D1	Analysis is not indicated in label	D13	Out of Holding Time	R1	Proceed as indicated in ☒ COC ☐ Label
D2	Analysis mismatch COC vs label	D14	Bubble is >6mm	R2	Refer to attached instruction (email)
D3	Sample ID mismatch COC vs label	D15	No trip blank in cooler	R3	Cancel the analysis
D4	Sample ID is not indicated in	D16	Preservation not indicated in label	R4	Use vial with smallest bubble first
D5	Container -[improper] [leaking] [broken]	D17	Preservation mismatch COC vs label	R5	Log-in with latest sampling date and time+1 min
D6	Date/Time is not indicated in	D18	Insufficient chemical preservative	R6	Adjust pH as necessary
D7	Date/Time mismatch COC vs label	D19	Insufficient Sample	R7	Filter and preserved as necessary
D8	Sample listed in COC is not received	D20	No filtration info for dissolved analysis	R8	Time on label is correct
D9	Sample received is not listed in COC	D21	No sample for moisture determination	R9	Time for TB should be 11:16
D10	No initial/date on corrections in COC/label	D22	No label	R10	
D11	Container count mismatch COC vs received	D23		R11	
D12	Container size mismatch COC vs received	D24		R12	

REVIEWS: Isabel Mata Sample Labeling Date 1/17/18 | 1/17/18   SRF Date 1/19/18   PM Date 1/18/18

EMAX Laboratories, Inc. 1835 W. 205th St., Torrance, Ca 90501

SAMPLE RECEIPT FORM 1

Type of Delivery	Airbill / Tracking Number	ECN 18A178
☑ Fedex ☐ UPS ☐ GSO ☐ Others	~~8085 3131 8955~~ a 1/19/18	Recipient Isabel Mata
☐ EMAX Courier ☐ Client Delivery	8085 3131 8944	Date 1/19/18 Time 0944

COC INSPECTION

☑ Client Name ☑ Client PM/FC ☑ Sampler Name ☑ Sampling Date/Time ☑ Sample ID ☑ Matrix
☑ Address ☑ Tel # / Fax # ☐ Courier Signature ☑ Analysis Required ☑ Preservative (if any) ☐ TAT
Safety Issues (if any) ☐ High concentrations expected ☐ From Superfund Site ☐ Rad screening required

Note:

PACKAGING INSPECTION

Container	☑ Cooler	☐ Box	☐ Other		
Condition	☐ Custody Seal a 1/19/18	☐ Intact	☐ Damaged		
Packaging	☑ Bubble Pack	☐ Styrofoam	☐ Popcorn	☑ Sufficient	☐ ______
Temperatures	☑ Cooler 1 2.0 °C	☑ Cooler 2 3.6 °C	☐ Cooler 3 ____ °C	☐ Cooler 4 ____ °C	☐ Cooler 5 ____ °C
(Cool, ≤6 °C but not frozen)	☐ Cooler 6 ____ °C	☐ Cooler 7 ____ °C	☐ Cooler 8 ____ °C	☐ Cooler 9 ____ °C	☐ Cooler 10 ____ °C
Thermometer:	A - S/N ____	B - S/N 1505555322	C - S/N ____	D S/N 1505555630	

Comments: ☐ **Temperature is out of range. PM was informed IMMEDIATELY.**
Note: Cooler arrived with other empty containers. *

DISCREPANCIES

LabSampleID	LabSampleContainerID	Code	ClientSample Label ID / Information	Corrective Action
1	15,16	D3	label has 01082016	R1
1	15,16	D7	Label has 11:14	R8
~~1~~	~~15,16~~		11:15	R8
1	15,16	D1		R1

IM 1/19/18

a 1/19/18 YM 1/19/18

☐ pH holding time requirement for water samples is 15 mins. Water samples for pH analysis are received beyond 15 minutes from sampling time.

NOTES/OBSERVATIONS: *(2) 2-1L w/H_2SO_4, (1) 250 w/HNO_3, (1) 125 amber, (6) vials unpres. Please Disregard these empty containers. YM 1/19

☐ **Continue to next page.**

LEGEND:

Code	Description- Sample Management	Code	Description-Sample Management	Code	Description-Sample Management
D1	Analysis is not indicated in label	D13	Out of Holding Time	R1	Proceed as indicated in ☐ COC ☐ Label
D2	Analysis mismatch COC vs label	D14	Bubble is >6mm	R2	Refer to attached instruction
D3	Sample ID mismatch COC vs label	D15	No trip blank in cooler	R3	Cancel the analysis
D4	Sample ID is not indicated in ____	D16	Preservation not indicated in ____	R4	Use vial with smallest bubble first
D5	Container -[improper] [leaking] [broken]	D17	Preservation mismatch COC vs label	R5	Log-in with latest sampling date and time+1 min
D6	Date/Time is not indicated in ____	D18	Insufficient chemical preservative	R6	Adjust pH as necessary
D7	Date/Time mismatch COC vs label	D19	Insufficient Sample	R7	Filter and preserved as necessary
D8	Sample listed in COC is not received	D20	No filtration info for dissolved analysis	R8	collection time is 11:15 per client.
D9	Sample received is not listed in COC	D21	No sample for moisture determination	R9	
D10	No initial/date on corrections in COC/label	D22		R10	
D11	Container count mismatch COC vs received	D23		R11	
D12	Container size mismatch COC vs received	D24		R12	

REVIEWS: Sample Labeling Isabel Mata [signature] Date ~~1/18~~ 1/18/18 1/19/18 IM 1/19/18
SRF [signature] Date 1/19/18
PM [signature] Date 1/19/18

EMAX Laboratories, Inc. 1835 W. 205th St., Torrance, Ca 90501

Ye Myint

From: Ron Quesada [rquesada@ORMAT.COM]
Sent: Wednesday, January 17, 2018 2:43 PM
To: Ye Myint
Cc: Linh Pham; Cecilia Chavez
Subject: RE: COCs/SRFs for 18A178

Attached are the COC and SRFs for samples received today for Type 3 and 4.

- Collection date and time do not match between COC and labels. Please advise. Collection date is 1/15. YM: How about collection time? Time on labels is correct too?. You are correct the collection time is incorrect on the COC but correct on the labels, time should be 1015.
- The lab did not receive Unpreserved 1L Ambers for TCLP Analyses (TCLP Metals, TCLP SVOCs). How did this happen...we sent back what you sent us? YM: Based on the bottle order record (above), 1L Ambers were sent to you with the lot #01082019 . A copy of this bottle order was also included with the supplies. Were you able to confirm what you received was consistent with what's on the bottle order? For all future supplies, could you please verify all the bottles are received as listed on the bottle order? I found the bottles, I just need to get a cooler to send them to you.
  - We did receive 1 x 500 ml Poly unpreserved that should be for pH and Ignitability. We can use an aliquot (150 ml) from this bottle for TCLP metals. We need a minimum of 100 ml sample for TCLP SVOCs. However, Poly plastic containers are not recommended for SVOCs. Please advise how you would like us to proceed. Can you compare the last cycle of sampling analysis results with this sample and if there is no change I am ok with using this sample. If not them we need to resample. YM: Results for this sample including TCLP SVOC will be emailed to you when available. Please compare the data with your historical data to make decision for your project and let us know if you decided to re-sample. This should not be an issue once you get the missed bottles.
- Sample ID does not match the ID on label (ID on label is B7003CNBS 101617-3...). We will default to the ID listed on COC. OK

Ron

From: Ye Myint [mailto:YMyint@emaxlabs.com]
Sent: Wednesday, January 17, 2018 12:08 PM
To: Ron Quesada <rquesada@ORMAT.COM>
Cc: Linh Pham <LPham@emaxlabs.com>; Cecilia Chavez <CChavez@emaxlabs.com>
Subject: RE: COCs/SRFs for 18A178

*****Please be aware : This is an EXTERNAL EMAIL*****

Hi Ron,

Please see below and also my notes to your responses. Thanks.

REQUISITION FORM FOR SAMPLING SUPPLIES

REQUISITION NO

Client	Puna Geothermal Venture	Client Request Received On	01/02/18
Project	UIC Type 3 and type 4	Project Code	
Attention	**Muriel Ahuna-Leong**	Requested By	Linh
Address	14-3860 Kapoho Pahoa Rd.	Date Requested	01/03/18
City/State/Zip	Pahoa, HI 96778	Deliver By	01/09/18
Phone:	(808) 965-6233 Ext. 52826		

Analysis		Containers			Preservative		
Analysis	Qty	Type	Qty	Lot #	Type	ID/Lot #	A
TCLP (Inorganics)	1	1L Amber	2	01082019 ✓	None		
Reactive CN/ Sulfide	1	500 ml Poly	1	00069255 ✓	NaOH/Zn acetate	SP18-1054-01 SNP1-01-995	
pH and Ignit.	1	500 ml Poly	1	↓ ✓	None		
TCLP VOCs	1	40 ml VOA	6	101617-3 ✓	None		
8260B	1	40 ml VOA	3	B70030VB5 ✓	HCl	166313	
		Trip Blanks	3	B70030VB9 ✓	HCl	18-004-01-16	

Ye
310-618-8889x121

EMAX is interested in your feedback; please provide your comments to: customerservice@emaxlabs.com.

Note : EMAX will be closed on 01/15/18 in observance of Martin Luther King Jr. Day.

From: Ron Quesada [mailto:rquesada@ORMAT.COM]
Sent: Wednesday, January 17, 2018 1:10 PM
To: Ye Myint
Cc: Linh Pham
Subject: RE: COCs/SRFs for 18A178

Hi Muriel,

Attached are the COC and SRFs for samples received today for Type 3 and 4.

- Collection date and time do not match between COC and labels. Please advise. Collection date is 1/15. YM: How about collection time? Time on labels is correct too?.
- The lab did not receive Unpreserved 1L Ambers for TCLP Analyses (TCLP Metals, TCLP SVOCs). How did this happen...we sent back what you sent us? YM: Based on the bottle order record (above), 1L Ambers were sent to you with the lot #01082019 . A copy of this bottle order was also included with the supplies. Were you able to confirm what you received was consistent with what's on the bottle order? For all future supplies, could you please verify all the bottles are received as listed on the bottle order?

- We did receive 1 x 500 ml Poly unpreserved that should be for pH and Ignitability. We can use an aliquot (150 ml) from this bottle for TCLP metals. We need a minimum of 100 ml sample for TCLP SVOCs. However, Poly plastic containers are not recommended for SVOCs. Please advise how you would like us to proceed. Can you compare the last cycle of sampling analysis results with this sample and if there is no change I am ok with using this sample. If not them we need to resample. YM: Results for this sample including TCLP SVOC will be emailed to you when available. Please compare the data with your historical data to make decision for your project and let us know if you decided to re-sample.

- Sample ID does not match the ID on label (ID on label is B7003CNBS 101617-3…). We will default to the ID listed on COC. OK

We are holding this SDG until the discrepancies are resolved. Please let us know if you have any questions.

Muriel is no longer employed with the company, please make me your primary contact…thanks. YM: Will do.

Thanks.

From: Ye Myint [mailto:YMyint@emaxlabs.com]
Sent: Wednesday, January 17, 2018 10:18 AM
To: Muriel Ahuna-Leong <mahuna@ORMAT.COM>
Cc: Muriel Ahuna-Leong <mahuna@ORMAT.COM>; Ron Quesada <rquesada@ORMAT.COM>; Linh Pham <LPham@emaxlabs.com>
Subject: COCs/SRFs for 18A178

*****Please be aware : This is an EXTERNAL EMAIL*****

Hi Muriel,

Attached are the COC and SRFs for samples received today for Type 3 and 4.

- Collection date and time do not match between COC and labels. Please advise.
- The lab did not receive Unpreserved 1L Ambers for TCLP Analyses (TCLP Metals, TCLP SVOCs).
  - We did receive 1 x 500 ml Poly unpreserved that should be for pH and Ignitability. We can use an aliquot (150 ml) from this bottle for TCLP metals. We need a minimum of 100 ml sample for TCLP SVOCs. However, Poly plastic containers are not recommended for SVOCs. Please advise how you would like us to proceed.
- Sample ID does not match the ID on label (ID on label is B7003CNBS 101617-3…). We will default to the ID listed on COC.

We are holding this SDG until the discrepancies are resolved. Please let us know if you have any questions.

Thanks.

Ye Myint
Project Manager
1835W 205th Street
Torrance, CA 90501
Phone : (310) 618-8889 Ext. 121
Fax : 310-618-0818

EMAX is interested in your feedback; please provide your comments to: customerservice@emaxlabs.com.

00096

00100 **FedEx** Express Package US Airbill

FedEx Tracking Number 8085 3131 8944

Form ID No. 0215

SLA2

13460

1 From [redacted]

Date 1/16/18

Sender's Name Ron Quesada Phone 808 430 8679

Company PUNA [illegible]

Address [illegible] Dept./Floor/Suite/Room

City PAHOA State [illegible] ZIP [illegible]

2 Your Internal Billing Reference

3 To

Recipient's Name YE MYINT Phone 310 618 3899

Company E MAX

Address 1835 W 205 TH ST. Dept./Floor/Suite/Room

We cannot deliver to P.O. boxes or P.O. ZIP codes.

HOLD Weekday FedEx location address REQUIRED. NOT available for FedEx First Overnight

Address

Use this line for the HOLD location address or for continuation of your shipping address.

HOLD Saturday FedEx location address REQUIRED. Available ONLY for FedEx Priority Overnight and FedEx 2Day to select locations

City TORRANCE State CA ZIP 90501

8085 3131 8944

fedex.com 1.800.GoFedEx 1.800.463.3339

0560102?

4 Express Package Service * To most locations.

NOTE: Service order has changed. Please select carefully.

Packages up to 150 lbs. *For packages over 150 lbs., use the FedEx Express Freight US Airbill.*

Next Business Day

- [x] FedEx First Overnight — Earliest next business morning delivery to select locations. Friday shipments will be delivered on Monday unless SATURDAY Delivery is selected.
- [ ] FedEx Priority Overnight — Next business morning.* Friday shipments will be delivered on Monday unless SATURDAY Delivery is selected.
- [ ] FedEx Standard Overnight — Next business afternoon.* Saturday Delivery NOT available.

2 or 3 Business Days

- [ ] FedEx 2Day A.M. — Second business morning.* Saturday Delivery NOT available.
- [ ] FedEx 2Day — Second business afternoon.* Thursday shipments will be delivered on Monday unless SATURDAY Delivery is selected.
- [ ] FedEx Express Saver — Third business day.* Saturday Delivery NOT available.

5 Packaging * Declared value limit $500

- [ ] FedEx Envelope*
- [ ] FedEx Pak*
- [ ] FedEx Box
- [ ] FedEx Tube
- [x] Other

6 Special Handling and Delivery Signature Options

- [ ] SATURDAY Delivery — NOT available for FedEx Standard Overnight, FedEx 2Day A.M., or FedEx Express Saver
- [ ] No Signature Required — Package may be left without obtaining a signature for delivery.
- [ ] Direct Signature — Someone at recipient's address may sign for delivery. Fee applies.
- [ ] Indirect Signature — If no one is available at recipient's address, someone at a neighboring address may sign for delivery. For residential deliveries only. Fee applies.

Does this shipment contain dangerous goods?

One box must be checked.

- [x] No
- [ ] Yes — As per attached Shipper's Declaration.
- [ ] Yes — Shipper's Declaration not required.
- [ ] Dry Ice — Dry Ice, 9, UN 1845 ____ x ____ kg

Dangerous goods (including dry ice) cannot be shipped in FedEx packaging or placed in a FedEx Express Drop Box.

- [ ] Cargo Aircraft Only

7 Payment *Bill to:*

Enter FedEx Acct. No. or Credit Card No. below.

Obtain recip. Acct. No. [ ]

- [x] Sender — Acct. No. in Section 1 will be billed.
- [ ] Recipient
- [ ] Third Party
- [ ] Credit Card
- [ ] Cash/Check

[redacted]

Total Packages 1 Total Weight 10 lbs. Credit Card Auth.

†Our liability is limited to US$100 unless you declare a higher value. See the current FedEx Service Guide for details.

611

fedex.com 1.800.GoFedEx 1.800.463.3339

00097

00100

13460

FedEx Express Package US Airbill

FedEx Tracking Number 8085 3131 8955

Form ID No. 0215

SLAB

1 From

Date 1/16/18 [redacted]

Sender's Name Ben Guessara Phone 808 430 8675

Company

Address

Dept./Floor/Suite/Room

City State ZIP

2 Your Internal Billing Reference

3 To

Recipient's Name Ve Hayat Phone 310 616 8889

Company Hiray Lan... Inc

Address 1635 W 205th St

We cannot deliver to P.O. boxes or P.O. ZIP codes. Dept./Floor/Suite/Room

HOLD Weekday FedEx location address REQUIRED. NOT available for FedEx First Overnight.

Address

Use this line for the HOLD location address or for continuation of your shipping address.

HOLD Saturday FedEx location address REQUIRED. Available ONLY for FedEx Priority Overnight and FedEx 2Day to select locations.

City Torrance State CA ZIP 90501

8085 3131 8955

fedex.com 1.800.GoFedEx 1.800.463.3339

05601027

4 Express Package Service

*To most locations.

NOTE: Service order has changed. Please select carefully.

Packages up to 150 lbs. For packages over 150 lbs., use the FedEx Express Freight US Airbill.

Next Business Day

- [x] FedEx First Overnight — Earliest next business morning delivery to select locations. Friday shipments will be delivered on Monday unless SATURDAY Delivery is selected.
- [ ] FedEx Priority Overnight — Next business morning.* Friday shipments will be delivered on Monday unless SATURDAY Delivery is selected.
- [ ] FedEx Standard Overnight — Next business afternoon.* Saturday Delivery NOT available.

2 or 3 Business Days

- [ ] FedEx 2Day A.M. — Second business morning.* Saturday Delivery NOT available.
- [ ] FedEx 2Day — Second business afternoon.* Thursday shipments will be delivered on Monday unless SATURDAY Delivery is selected.
- [ ] FedEx Express Saver — Third business day.* Saturday Delivery NOT available.

5 Packaging

*Declared value limit $500.

- [ ] FedEx Envelope*
- [ ] FedEx Pak*
- [ ] FedEx Box
- [ ] FedEx Tube
- [x] Other

6 Special Handling and Delivery Signature Options

- [ ] SATURDAY Delivery — NOT available for FedEx Standard Overnight, FedEx 2Day A.M., or FedEx Express Saver.
- [ ] No Signature Required — Package may be left without obtaining a signature for delivery
- [ ] Direct Signature — Someone at recipient's address may sign for delivery. *Fee applies.*
- [ ] Indirect Signature — If no one is available at recipient's address, someone at a neighboring address may sign for delivery. For residential deliveries only. *Fee applies.*

Does this shipment contain dangerous goods?

One box must be checked.

- [x] No
- [ ] Yes — As per attached Shipper's Declaration.
- [ ] Yes — Shipper's Declaration not required.
- [ ] Dry Ice — Dry Ice, 9, UN 1845 ____ x ____ kg

Dangerous goods (including dry ice) cannot be shipped in FedEx packaging or placed in a FedEx Express Drop Box.

- [ ] Cargo Aircraft Only

7 Payment Bill to:

Enter FedEx Acct. No. or Credit Card No. below.

- [ ] Sender — Acct. No. in Section 1 will be billed.
- [ ] Recipient
- [ ] Third Party
- [ ] Credit Card
- [ ] Cash/Check

Obtain recip Acct. No.

[redacted]

Total Packages 1 Total Weight 10 lbs. [redacted] Credit Card Auth.

†Our liability is limited to US$100 unless you declare a higher value. See the current FedEx Service Guide for details.

611

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fedex.com 1.800.GoFedEx 1.800.463.3339

REPORTING CONVENTIONS

DATA QUALIFIERS:

Lab Qualifier	AFCEE Qualifier	Description
J	F	Indicates that the analyte is positively identified and the result is less than RL but greater than MDL.
N		Indicates presumptive evidence of a compound.
B	B	Indicates that the analyte is found in the associated method blank as well as in the sample at above QC level.
E	J	Indicates that the result is above the maximum calibration range or estimated value.
*	*	Out of QC limit.

Note: The above qualifiers are used to flag the results unless the project requires a different set of qualification criteria.

ACRONYMS AND ABBREVIATIONS:

CRDL	Contract Required Detection Limit
RL	Reporting Limit
MRL	Method Reporting Limit
PQL	Practical Quantitation Limit
MDL	Method Detection Limit
DO	Diluted out

DATES

The date and time information for leaching and preparation reflect the beginning date and time of the procedure unless the method, protocol, or project specifically requires otherwise.

LABORATORY REPORT FOR

PUNA GEOTHERMAL VENTURE

PUNA GEOTHERMAL VENTURE

METHOD 5030B/8260B
VOLATILE ORGANICS BY GC/MS

SDG#: 18A178

CASE NARRATIVE

Client : PUNA GEOTHERMAL VENTURE

Project: PUNA GEOTHERMAL VENTURE

SDG : 18A178

METHOD 5030B/8260B
VOLATILE ORGANICS BY GC/MS

Two (2) water samples were received on 01/17/18 to be analyzed for Volatile Organics by GC/MS in accordance with Method 5030B/8260B and project specific requirements.

Holding Time
The sample was analyzed within the prescribed holding time.

Instrument Performance and Calibration
Instrument tune check was performed prior to calibration. Result was within acceptance criteria. Multi-calibration points were generated to establish initial calibration (ICAL). ICAL was verified using secondary source (ICV). Continuing calibration (CCV) was carried out at a frequency required by the project. All project calibration requirements were satisfied. Refer to calibration summary forms of ICAL, ICV and CCV for details.

Method Blank
Method blank was prepared and analyzed at the frequency required by the project. For this SDG, one (1) method blank was analyzed. VW02A15B was compliant to project requirement. Refer to sample result summary forms for details.

Lab Control Sample
Lab control sample was prepared and analyzed at a frequency required by the project. For this SDG, one (1) set of LCS/LCD was analyzed. VW02A15L/VW02A15C were within LCS limits. Refer to LCS summary form for details.

Matrix QC Sample
No matrix QC sample was designated on this SDG.

Surrogate
Surrogates were added on QC and field samples. All surrogate recoveries were within QC limits. Refer to sample result summary forms for details.

Sample Analysis
The sample was analyzed according to prescribed analytical procedures. Results were evaluated in accordance to project requirements. For this SDG, all quality control requirements were met.

LAB CHRONICLE
VOLATILE ORGANICS BY GC/MS

Client : PUNA GEOTHERMAL VENTURE
Project : PUNA GEOTHERMAL VENTURE

SDG NO. : 18A178
Instrument ID : 02

WATER

Client Sample ID	Laboratory Sample ID	Dilution Factor	% Moist	Analysis DateTime	Extraction DateTime	Sample Data FN	Calibration Data FN	Prep. Batch	Notes
MBLK1W	VW02A15B	1	NA	01/22/1812:45	01/22/1812:45	RAP231	RKP409	VW02A25	Method Blank
LCS1W	VW02A15L	1	NA	01/22/1811:05	01/22/1811:05	RAP227	RKP409	VW02A25	Lab Control Sample (LCS)
LCD1W	VW02A15C	1	NA	01/22/1811:30	01/22/1811:30	RAP228	RKP409	VW02A25	LCS Duplicate
TRIP BLANK	A178-02	1	NA	01/22/1816:05	01/22/1816:05	RAP239	RKP409	VW02A25	Field Sample
TYPE 3 & 4 INJECTATE	A178-01	1	NA	01/22/1816:30	01/22/1816:30	RAP240	RKP409	VW02A25	Field Sample

FN - Filename
% Moist - Percent Moisture

SAMPLE RESULTS

METHOD SW5030B/SW8260B
VOLATILE ORGANICS BY GC/MS

Client : PUNA GEOTHERMAL VENTURE	Date Collected: 01/15/18
Project : PUNA GEOTHERMAL VENTURE	Date Received: 01/17/18
Batch No. : 18A178	Date Extracted: 01/22/18 16:30
Sample ID: TYPE 3 & 4 INJECTATE	Date Analyzed: 01/22/18 16:30
Lab Samp ID: A178-01	Dilution Factor: 1
Lab File ID: RAP240	Matrix : WATER
Ext Btch ID: VW02A25	% Moisture : NA
Calib. Ref.: RKP409	Instrument ID : T-002

PARAMETERS	RESULTS (ug/L)	RL (ug/L)	MDL (ug/L)
BENZENE	22	1.0	0.20

SURROGATE PARAMETERS	RESULTS	SPK_AMT	% RECOVERY	QC LIMIT
1,2-DICHLOROETHANE-D4	49.0	50.00	98.1	70-140
4-BROMOFLUOROBENZENE	49.4	50.00	98.8	70-130
TOLUENE-D8	54.1	50.00	108	70-140

METHOD SW5030B/SW8260B
VOLATILE ORGANICS BY GC/MS

Client : PUNA GEOTHERMAL VENTURE	Date Collected: 01/15/18
Project : PUNA GEOTHERMAL VENTURE	Date Received: 01/17/18
Batch No. : 18A178	Date Extracted: 01/22/18 16:05
Sample ID: TRIP BLANK	Date Analyzed: 01/22/18 16:05
Lab Samp ID: A178-02	Dilution Factor: 1
Lab File ID: RAP239	Matrix : WATER
Ext Btch ID: VW02A25	% Moisture : NA
Calib. Ref.: RKP409	Instrument ID : T-002

PARAMETERS	RESULTS (ug/L)	RL (ug/L)	MDL (ug/L)
BENZENE	ND	1.0	0.20

SURROGATE PARAMETERS	RESULTS	SPK_AMT	% RECOVERY	QC LIMIT
1,2-DICHLOROETHANE-D4	47.8	50.00	95.6	70-140
4-BROMOFLUOROBENZENE	52.0	50.00	104	70-130
TOLUENE-D8	55.4	50.00	111	70-140

QC SUMMARIES

METHOD SW5030B/SW8260B
VOLATILE ORGANICS BY GC/MS

Client : PUNA GEOTHERMAL VENTURE	Date Collected: NA
Project : PUNA GEOTHERMAL VENTURE	Date Received: 01/22/18
Batch No. : 18A178	Date Extracted: 01/22/18 12:45
Sample ID: MBLK1W	Date Analyzed: 01/22/18 12:45
Lab Samp ID: VW02A15B	Dilution Factor: 1
Lab File ID: RAP231	Matrix : WATER
Ext Btch ID: VW02A25	% Moisture : NA
Calib. Ref.: RKP409	Instrument ID : T-002

PARAMETERS	RESULTS (ug/L)	RL (ug/L)		MDL (ug/L)
BENZENE	ND	1.0		0.20

SURROGATE PARAMETERS	RESULTS	SPK_AMT	% RECOVERY	QC LIMIT
1,2-DICHLOROETHANE-D4	48.2	50.00	96.4	70-140
4-BROMOFLUOROBENZENE	49.7	50.00	99.4	70-130
TOLUENE-D8	55.3	50.00	111	70-130

EMAX QUALITY CONTROL DATA
LCS/LCD ANALYSIS

CLIENT: PUNA GEOTHERMAL VENTURE
PROJECT: PUNA GEOTHERMAL VENTURE
BATCH NO.: 18A178
METHOD: METHOD SW5030B/SW8260B

MATRIX:	WATER			% MOISTURE:	NA
DILUTION FACTOR:	1	1	1		
SAMPLE ID:	MBLK1W				
LAB SAMP ID:	VW02A15B	VW02A15L	VW02A15C		
LAB FILE ID:	RAP231	RAP227	RAP228		
DATE EXTRACTED:	01/22/1812:45	01/22/1811:05	01/22/1811:30	DATE COLLECTED:	NA
DATE ANALYZED:	01/22/1812:45	01/22/1811:05	01/22/1811:30	DATE RECEIVED:	01/22/18
PREP. BATCH:	VW02A25	VW02A25	VW02A25		
CALIB. REF:	RKP409	RKP409	RKP409		

ACCESSION:

PARAMETER	BLNK RSLT (ug/L)	SPIKE AMT (ug/L)	BS RSLT (ug/L)	BS % REC	SPIKE AMT (ug/L)	BSD RSLT (ug/L)	BSD % REC	RPD (%)	QC LIMIT (%)	MAX RPD (%)
Benzene	ND	50.0	49.8	100	50.0	51.3	103	3	70-130	30

SURROGATE PARAMETER	SPIKE AMT (ug/L)	BS RSLT (ug/L)	BS % REC	SPIKE AMT (ug/L)	BSD RSLT (ug/L)	BSD % REC	QC LIMIT (%)
1,2-Dichloroethane-d4	50.0	46.3	93	50.0	46.8	94	70-140
4-Bromofluorobenzene	50.0	50.8	102	50.0	50.8	102	70-130
Toluene-d8	50.0	52.9	106	50.0	52.5	105	70-130

LABORATORY REPORT FOR

PUNA GEOTHERMAL VENTURE

PUNA GEOTHERMAL VENTURE

METHOD 1311/5030B/8260B
TCLP VOLATILE ORGANICS BY GC/MS

SDG#: 18A178

CASE NARRATIVE

Client : PUNA GEOTHERMAL VENTURE

Project: PUNA GEOTHERMAL VENTURE

SDG : 18A178

METHOD 1311/5030B/8260B
TCLP VOLATILE ORGANICS BY GC/MS

One (1) water sample was received on 01/17/18 to be analyzed for TCLP Volatile Organics by GC/MS in accordance with Method 1311/5030B/8260B and project specific requirements.

Holding Time
The sample was analyzed within the prescribed holding time.

Instrument Performance and Calibration
Instrument tune check was performed prior to calibration. Result was within acceptance criteria. Multi-calibration points were generated to establish initial calibration (ICAL). ICAL was verified using secondary source (ICV). Continuing calibration (CCV) was carried out at a frequency required by the project. All project calibration requirements were satisfied. Refer to calibration summary forms of ICAL, ICV and CCV for details.

Method Blank
Method blank was prepared and analyzed at the frequency required by the project. For this SDG, two (2) method blanks were analyzed. TVA003WB and VW02A16B were compliant to project requirement. Refer to sample result summary forms for details.

Lab Control Sample
Lab control sample was prepared and analyzed at a frequency required by the project. For this SDG, one (1) set of LCS/LCD was analyzed. VW02A16L/VW02A16C were within LCS limits. Refer to LCS summary form for details.

Matrix QC Sample
Matrix spike sample was prepared and analyzed at a frequency required by the project. For this SDG, one (1) set of MS/MSD was analyzed. A178-01M/A178-01S - all analytes were within MS QC limits. Refer to Matrix QC summary form for details.

Surrogate
Surrogates were added on QC and field samples. All surrogate recoveries were within QC limits. Refer to sample result summary forms for details.

Sample Analysis
The sample was analyzed according to prescribed analytical procedures. Results were evaluated in accordance to project requirements. For this SDG, all quality control requirements were met.

LAB CHRONICLE
TCLP VOLATILE ORGANICS BY GC/MS

Client	: PUNA GEOTHERMAL VENTURE	SDG NO.	: 18A178
Project	: PUNA GEOTHERMAL VENTURE	Instrument ID	: 02

LEACHATE

Client Sample ID	Laboratory Sample ID	Dilution Factor	% Moist	Analysis DateTime	Extraction DateTime	Sample Data FN	Calibration Data FN	Prep. Batch	Notes
MBLK1W	VW02A16B	1	NA	01/23/1811:31	01/23/1811:31	RAP258	RKP409	VW02A16	Method Blank
LCS1W	VW02A16L	1	NA	01/23/1810:15	01/23/1810:15	RAP255	RKP409	VW02A16	Lab Control Sample (LCS)
LCD1W	VW02A16C	1	NA	01/23/1810:40	01/23/1810:40	RAP256	RKP409	VW02A16	LCS Duplicate
MBLK2W	TVA003WB	10	NA	01/23/1811:56	01/23/1811:56	RAP259	RKP409	VW02A16	Method Blank
TYPE 3 & 4 INJECTATE	A178-01	10	NA	01/23/1812:21	01/23/1812:21	RAP260	RKP409	VW02A16	Field Sample
TYPE 3 & 4 INJECTATEMS	A178-01M	10	NA	01/23/1812:46	01/23/1812:46	RAP261	RKP409	VW02A16	Matrix Spike Sample (MS)
TYPE 3 & 4 INJECTATEMSD	A178-01S	10	NA	01/23/1813:11	01/23/1813:11	RAP262	RKP409	VW02A16	MS Duplicate (MSD)

FN - Filename
% Moist - Percent Moisture

SAMPLE RESULTS

METHOD 1311/5030B/8260B
TCLP VOLATILE ORGANICS BY GC/MS

Client	: PUNA GEOTHERMAL VENTURE	Date Collected:	01/15/18
Project	: PUNA GEOTHERMAL VENTURE	Date Received:	01/17/18
Batch No.	: 18A178	Date Extracted:	01/23/18 12:21
Sample ID:	TYPE 3 & 4 INJECTATE	Date Analyzed:	01/23/18 12:21
Lab Samp ID:	A178-01	Dilution Factor:	10
Lab File ID:	RAP260	Matrix	: LEACHATE
Ext Btch ID:	VW02A16	% Moisture	: NA
Calib. Ref.:	RKP409	Instrument ID	: T-002

PARAMETERS	RESULTS (ug/L)	RL (ug/L)	MDL (ug/L)
BENZENE	19J	50	10
METHYL ETHYL KETONE	ND	100	50
CARBON TETRACHLORIDE	ND	50	10
CHLOROBENZENE	ND	50	10
CHLOROFORM	ND	50	10
1,4-DICHLOROBENZENE	ND	50	10
1,2-DICHLOROETHANE	ND	50	10
1,1-DICHLOROETHENE	ND	50	10
TETRACHLOROETHENE	ND	50	10
TRICHLOROETHENE	ND	50	10
VINYL CHLORIDE	ND	50	10

SURROGATE PARAMETERS	RESULTS	SPK_AMT	% RECOVERY	QC LIMIT
1,2-DICHLOROETHANE-D4	479	500.0	95.7	70-140
4-BROMOFLUOROBENZENE	490	500.0	97.9	70-130
TOLUENE-D8	544	500.0	109	70-140

DateTime Leached: 01/19/18 15:15

QC SUMMARIES

METHOD 1311/5030B/8260B
TCLP VOLATILE ORGANICS BY GC/MS

Client	: PUNA GEOTHERMAL VENTURE	Date Collected:	NA
Project	: PUNA GEOTHERMAL VENTURE	Date Received:	01/23/18
Batch No.	: 18A178	Date Extracted:	01/23/18 11:31
Sample ID:	MBLK1W	Date Analyzed:	01/23/18 11:31
Lab Samp ID:	VW02A16B	Dilution Factor:	1
Lab File ID:	RAP258	Matrix	: WATER
Ext Btch ID:	VW02A16	% Moisture	: NA
Calib. Ref.:	RKP409	Instrument ID	: T-002

PARAMETERS	RESULTS (ug/L)	RL (ug/L)	MDL (ug/L)
BENZENE	ND	5.0	1.0
METHYL ETHYL KETONE	ND	10	5.0
CARBON TETRACHLORIDE	ND	5.0	1.0
CHLOROBENZENE	ND	5.0	1.0
CHLOROFORM	ND	5.0	1.0
1,4-DICHLOROBENZENE	ND	5.0	1.0
1,2-DICHLOROETHANE	ND	5.0	1.0
1,1-DICHLOROETHENE	ND	5.0	1.0
TETRACHLOROETHENE	ND	5.0	1.0
TRICHLOROETHENE	ND	5.0	1.0
VINYL CHLORIDE	ND	5.0	1.0

SURROGATE PARAMETERS	RESULTS	SPK_AMT	% RECOVERY	QC LIMIT
1,2-DICHLOROETHANE-D4	46.7	50.00	93.5	70-140
4-BROMOFLUOROBENZENE	48.3	50.00	96.7	70-130
TOLUENE-D8	55.2	50.00	110	70-130

EMAX QUALITY CONTROL DATA
LCS/LCD ANALYSIS

CLIENT: PUNA GEOTHERMAL VENTURE
PROJECT: PUNA GEOTHERMAL VENTURE
BATCH NO.: 18A178
METHOD: METHOD 1311/5030B/8260B

MATRIX:	WATER			% MOISTURE:	NA
DILUTION FACTOR:	1	1	1		
SAMPLE ID:	MBLK1W				
LAB SAMP ID:	VW02A16B	VW02A16L	VW02A16C		
LAB FILE ID:	RAP258	RAP255	RAP256		
DATE EXTRACTED:	01/23/1811:31	01/23/1810:15	01/23/1810:40	DATE COLLECTED:	NA
DATE ANALYZED:	01/23/1811:31	01/23/1810:15	01/23/1810:40	DATE RECEIVED:	01/23/18
PREP. BATCH:	VW02A16	VW02A16	VW02A16		
CALIB. REF:	RKP409	RKP409	RKP409		

ACCESSION:

PARAMETER	BLNK RSLT (ug/L)	SPIKE AMT (ug/L)	BS RSLT (ug/L)	BS % REC	SPIKE AMT (ug/L)	BSD RSLT (ug/L)	BSD % REC	RPD (%)	QC LIMIT (%)	MAX RPD (%)
Benzene	ND	50.0	56.7	113	50.0	52.0	104	9	70-130	30
Methyl Ethyl Ketone	ND	250	246	98	250	254	102	3	60-140	30
Carbon Tetrachloride	ND	50.0	59.5	119	50.0	55.5	111	7	70-130	30
Chlorobenzene	ND	50.0	55.9	112	50.0	51.5	103	8	70-130	30
Chloroform	ND	50.0	53.0	106	50.0	48.3	97	9	70-130	30
1,4-Dichlorobenzene	ND	50.0	55.9	112	50.0	52.0	104	7	70-130	30
1,2-Dichloroethane	ND	50.0	52.6	105	50.0	49.2	98	7	70-130	30
1,1-Dichloroethene	ND	50.0	56.3	113	50.0	51.4	103	9	60-130	30
Tetrachloroethene	ND	50.0	54.5	109	50.0	50.2	100	8	70-130	30
Trichloroethene	ND	50.0	55.1	110	50.0	50.6	101	9	70-130	30
Vinyl Chloride	ND	50.0	48.8	98	50.0	45.1	90	8	60-150	30

SURROGATE PARAMETER	SPIKE AMT (ug/L)	BS RSLT (ug/L)	BS % REC	SPIKE AMT (ug/L)	BSD RSLT (ug/L)	BSD % REC	QC LIMIT (%)
1,2-Dichloroethane-d4	50.0	46.1	92	50.0	46.1	92	70-140
4-Bromofluorobenzene	50.0	49.2	98	50.0	48.8	98	70-130
Toluene-d8	50.0	52.2	104	50.0	52.5	105	70-130

METHOD 1311/5030B/8260B
TCLP VOLATILE ORGANICS BY GC/MS

Client : PUNA GEOTHERMAL VENTURE	Date Collected: NA
Project : PUNA GEOTHERMAL VENTURE	Date Received: 01/23/18
Batch No. : 18A178	Date Extracted: 01/23/18 11:56
Sample ID: MBLK2W	Date Analyzed: 01/23/18 11:56
Lab Samp ID: TVA003WB	Dilution Factor: 10
Lab File ID: RAP259	Matrix : LEACHATE
Ext Btch ID: VW02A16	% Moisture : NA
Calib. Ref.: RKP409	Instrument ID : T-002

PARAMETERS	RESULTS (ug/L)	RL (ug/L)	MDL (ug/L)
BENZENE	ND	50	10
METHYL ETHYL KETONE	ND	100	50
CARBON TETRACHLORIDE	ND	50	10
CHLOROBENZENE	ND	50	10
CHLOROFORM	ND	50	10
1,4-DICHLOROBENZENE	ND	50	10
1,2-DICHLOROETHANE	ND	50	10
1,1-DICHLOROETHENE	ND	50	10
TETRACHLOROETHENE	ND	50	10
TRICHLOROETHENE	ND	50	10
VINYL CHLORIDE	ND	50	10

SURROGATE PARAMETERS	RESULTS	SPK_AMT	% RECOVERY	QC LIMIT
1,2-DICHLOROETHANE-D4	473	500.0	94.5	70-140
4-BROMOFLUOROBENZENE	494	500.0	98.7	70-130
TOLUENE-D8	544	500.0	109	70-130

DateTime Leached: 01/19/18 15:15

EMAX QUALITY CONTROL DATA
MS/MSD ANALYSIS

CLIENT: PUNA GEOTHERMAL VENTURE
PROJECT: PUNA GEOTHERMAL VENTURE
BATCH NO.: 18A178
METHOD: METHOD 1311/5030B/8260B

MATRIX:	LEACHATE			% MOISTURE:	NA
DILUTION FACTOR:	10	10	10		
SAMPLE ID:	TYPE 3 & 4 INJECTATE				
LAB SAMP ID:	A178-01	A178-01M	A178-01S		
LAB FILE ID:	RAP260	RAP261	RAP262		
DATE EXTRACTED:	01/23/1812:21	01/23/1812:46	01/23/1813:11	DATE COLLECTED:	01/15/18
DATE ANALYZED:	01/23/1812:21	01/23/1812:46	01/23/1813:11	DATE RECEIVED:	01/17/18
PREP. BATCH:	VW02A16	VW02A16	VW02A16		
CALIB. REF:	RKP409	RKP409	RKP409		

ACCESSION:

PARAMETER	SMPL RSLT (ug/L)	SPIKE AMT (ug/L)	MS RSLT (ug/L)	MS % REC	SPIKE AMT (ug/L)	MSD RSLT (ug/L)	MSD % REC	RPD (%)	QC LIMIT (%)	MAX RPD (%)
Benzene	19.4J	500	520	100	500	499	96	4	60-140	30
Methyl Ethyl Ketone	ND	2500	2660	106	2500	2550	102	4	60-150	30
Carbon Tetrachloride	ND	500	509	102	500	497	99	2	60-140	30
Chlorobenzene	ND	500	503	101	500	485	97	4	70-130	30
Chloroform	ND	500	469	94	500	458	92	2	70-130	30
1,4-Dichlorobenzene	ND	500	508	102	500	486	97	4	70-130	30
1,2-Dichloroethane	ND	500	489	98	500	473	95	3	70-140	30
1,1-Dichloroethene	ND	500	480	96	500	468	94	2	60-140	30
Tetrachloroethene	ND	500	496	99	500	467	93	6	70-130	30
Trichloroethene	ND	500	486	97	500	469	94	4	60-140	30
Vinyl Chloride	ND	500	345	69	500	329	66	5	60-160	30

SURROGATE PARAMETER	SPIKE AMT (ug/L)	MS RSLT (ug/L)	MS % REC	SPIKE AMT (ug/L)	MSD RSLT (ug/L)	MSD % REC	QC LIMIT (%)
1,2-Dichloroethane-d4	500	473	95	500	468	94	70-140
4-Bromofluorobenzene	500	504	101	500	489	98	70-130
Toluene-d8	500	531	106	500	524	105	70-140

DateTime Leached: 01/19/18 15:15

LABORATORY REPORT FOR

PUNA GEOTHERMAL VENTURE

PUNA GEOTHERMAL VENTURE

METHOD SW1311/3520C/8270C
TCLP SEMI VOLATILE ORGANICS BY GC/MS

SDG#: 18A178

CASE NARRATIVE

Client : PUNA GEOTHERMAL VENTURE

Project: PUNA GEOTHERMAL VENTURE

SDG : 18A178

METHOD SW1311/3520C/8270C
TCLP SEMI VOLATILE ORGANICS BY GC/MS

One (1) water sample was received on 01/17/18 to be analyzed for TCLP Semi Volatile Organics by GC/MS in accordance with Method SW1311/3520C/8270C and project specific requirements.

Holding Time
The sample was analyzed within the prescribed holding time.

Instrument Performance and Calibration
Instrument tune check was performed prior to calibration. Instrument mass ratios as well as DDT breakdown were evaluated. Results were within acceptance criteria. Tailing factor for Benzidine and Pentachlorophenol were also verified and results were within the method limits. Multi-calibration points were generated to establish initial calibration (ICAL). ICAL was verified using secondary source (ICV). Continuing calibration (CCV) was carried out at a frequency required by the project. There was one (1) CCV associated with this SDG. Target analytes in CCV (Data file ID: RAJ315) were within calibration acceptance criteria.. All calibration requirements were satisfied. Refer to calibration summary forms of ICAL, ICV and CCV for details.

Method Blank
Method blank was prepared and analyzed at the frequency required by the project. For this SDG, two (2) method blanks were analyzed. SVA025WB and TXA011WB were compliant to project requirement. Refer to sample result summary forms for details.

Lab Control Sample
Lab control sample was prepared and analyzed at a frequency required by the project. For this SDG, one (1) set of LCS/LCD was analyzed. SVA025WL/SVA025WC were within LCS limits. Refer to LCS summary form for details.

Matrix QC Sample
No matrix QC sample was provided on this SDG.

Surrogate
Surrogates were added on QC and field samples. All surrogate recoveries were within QC limits. Refer to sample result summary forms for details.

Sample Analysis
The sample was analyzed according to prescribed analytical procedures. Results were evaluated in accordance to project requirements. For this SDG, all quality control requirements were met.

LAB CHRONICLE

TCLP SEMI VOLATILE ORGANICS BY GC/MS

Client : PUNA GEOTHERMAL VENTURE
Project : PUNA GEOTHERMAL VENTURE

SDG NO. : 18A178
Instrument ID : E4

LEACHATE

Client Sample ID	Laboratory Sample ID	Dilution Factor	% Moist	Analysis DateTime	Extraction DateTime	Sample Data FN	Calibration Data FN	Prep. Batch	Notes
MBLK1W	SVA025WB	1	NA	01/24/1815:30	01/22/1814:30	RAJ333	RFJ007	SVA025W	Method Blank
LCS1W	SVA025WL	1	NA	01/24/1815:49	01/22/1814:30	RAJ334	RFJ007	SVA025W	Lab Control Sample (LCS)
LCD1W	SVA025WC	1	NA	01/24/1816:08	01/22/1814:30	RAJ335	RFJ007	SVA025W	LCS Duplicate
MBLK2W	TXA011WB	10	NA	01/24/1817:24	01/22/1814:30	RAJ339	RFJ007	SVA025W	Method Blank
TYPE 3 & 4 INJECTATE	A178-01	10	NA	01/24/1817:43	01/22/1814:30	RAJ340	RFJ007	SVA025W	Field Sample

FN - Filename
% Moist - Percent Moisture

SAMPLE RESULTS

SW1311/3520C/8270C
TCLP SEMI VOLATILE ORGANICS BY GC/MS

Client : PUNA GEOTHERMAL VENTURE	Date Collected: 01/15/18
Project : PUNA GEOTHERMAL VENTURE	Date Received: 01/17/18
Batch No. : 18A178	Date Extracted: 01/22/18 14:30
Sample ID: TYPE 3 & 4 INJECTATE	Date Analyzed: 01/24/18 17:43
Lab Samp ID: A178-01	Dilution Factor: 10
Lab File ID: RAJ340	Matrix : LEACHATE
Ext Btch ID: SVA025W	% Moisture : NA
Calib. Ref.: RFJ007	Instrument ID : T-OE4

PARAMETERS	RESULTS (ug/L)	RL (ug/L)	MDL (ug/L)
2,4,5-TRICHLOROPHENOL	ND	100	50
2,4,6-TRICHLOROPHENOL	ND	100	50
2,4-DINITROTOLUENE	ND	100	50
O-CRESOL	ND	100	50
P-CRESOL (1)	ND	100	50
HEXACHLOROBENZENE	ND	100	50
HEXACHLORO-1,3-BUTADIENE	ND	100	50
HEXACHLOROETHANE	ND	100	50
NITROBENZENE	ND	100	50
PYRIDINE	ND	400	200

SURROGATE PARAMETERS	RESULTS	SPK_AMT	% RECOVERY	QC LIMIT
2,4,6-TRIBROMOPHENOL	478	600.0	79.7	30-150
2-FLUOROBIPHENYL	171	200.0	85.6	30-130
2-FLUOROPHENOL	371	600.0	61.9	20-130
NITROBENZENE-D5	173	200.0	86.5	30-130
PHENOL-D5	442	600.0	73.7	30-130
TERPHENYL-D14	147	200.0	73.3	30-130

(1): Cannot be separated from m-Cresol
DateTime Leached: 01/19/18 12:00

QC SUMMARIES

SW1311/3520C/8270C
TCLP SEMI VOLATILE ORGANICS BY GC/MS

Client : PUNA GEOTHERMAL VENTURE	Date Collected: NA
Project : PUNA GEOTHERMAL VENTURE	Date Received: 01/22/18
Batch No. : 18A178	Date Extracted: 01/22/18 14:30
Sample ID: MBLK1W	Date Analyzed: 01/24/18 15:30
Lab Samp ID: SVA025WB	Dilution Factor: 1
Lab File ID: RAJ333	Matrix : WATER
Ext Btch ID: SVA025W	% Moisture : NA
Calib. Ref.: RFJ007	Instrument ID : T-OE4

PARAMETERS	RESULTS (ug/L)	RL (ug/L)	MDL (ug/L)
2,4,5-TRICHLOROPHENOL	ND	10	5.0
2,4,6-TRICHLOROPHENOL	ND	10	5.0
2,4-DINITROTOLUENE	ND	10	5.0
O-CRESOL	ND	10	5.0
P-CRESOL (1)	ND	10	5.0
HEXACHLOROBENZENE	ND	10	5.0
HEXACHLORO-1,3-BUTADIENE	ND	10	5.0
HEXACHLOROETHANE	ND	10	5.0
NITROBENZENE	ND	10	5.0
PYRIDINE	ND	40	20

SURROGATE PARAMETERS	RESULTS	SPK_AMT	% RECOVERY	QC LIMIT
2,4,6-TRIBROMOPHENOL	44.3	60.00	73.8	40-140
2-FLUOROBIPHENYL	16.1	20.00	80.4	40-130
2-FLUOROPHENOL	37.1	60.00	61.9	30-130
NITROBENZENE-D5	15.5	20.00	77.3	40-130
PHENOL-D5	42.8	60.00	71.3	30-130
TERPHENYL-D14	13.8	20.00	68.8	50-130

(1): Cannot be separated from m-Cresol

EMAX QUALITY CONTROL DATA
LCS/LCD ANALYSIS

CLIENT: PUNA GEOTHERMAL VENTURE
PROJECT: PUNA GEOTHERMAL VENTURE
BATCH NO.: 18A178
METHOD: SW1311/3520C/8270C

MATRIX:	WATER			% MOISTURE:	NA
DILUTION FACTOR:	1	1	1		
SAMPLE ID:	MBLK1W				
LAB SAMP ID:	SVA025WB	SVA025WL	SVA025WC		
LAB FILE ID:	RAJ333	RAJ334	RAJ335		
DATE EXTRACTED:	01/22/1814:30	01/22/1814:30	01/22/1814:30	DATE COLLECTED:	NA
DATE ANALYZED:	01/24/1815:30	01/24/1815:49	01/24/1816:08	DATE RECEIVED:	01/22/18
PREP. BATCH:	SVA025W	SVA025W	SVA025W		
CALIB. REF:	RFJ007	RFJ007	RFJ007		

ACCESSION:

PARAMETER	BLNK RSLT (ug/L)	SPIKE AMT (ug/L)	BS RSLT (ug/L)	BS % REC	SPIKE AMT (ug/L)	BSD RSLT (ug/L)	BSD % REC	RPD (%)	QC LIMIT (%)	MAX RPD (%)
2,4,5-Trichlorophenol	ND	40.0	43.3	108	40.0	43.0	108	0	40-130	30
2,4,6-Trichlorophenol	ND	40.0	42.1	105	40.0	42.4	106	1	40-130	30
2,4-Dinitrotoluene	ND	40.0	44.7	112	40.0	43.1	108	4	40-130	30
o-Cresol	ND	40.0	34.7	87	40.0	35.7	89	3	30-130	30
p-Cresol	ND	40.0	39.2	98	40.0	42.0	105	7	30-130	30
Hexachlorobenzene	ND	40.0	37.7	94	40.0	37.7	94	0	50-130	30
Hexachloro-1,3-butadiene	ND	40.0	36.2	91	40.0	37.3	93	3	20-130	30
Hexachloroethane	ND	40.0	32.7	82	40.0	34.1	85	4	20-130	30
Nitrobenzene	ND	40.0	35.2	88	40.0	36.8	92	5	30-130	30
Pyridine	ND	80.0	70.7	88	80.0	71.4	89	1	10-130	30

SURROGATE PARAMETER	SPIKE AMT (ug/L)	BS RSLT (ug/L)	BS % REC	SPIKE AMT (ug/L)	BSD RSLT (ug/L)	BSD % REC	QC LIMIT (%)
2,4,6-Tribromophenol	60.0	47.3	79	60.0	47.7	80	40-140
2-Fluorobiphenyl	20.0	16.0	80	20.0	16.7	83	40-130
2-Fluorophenol	60.0	34.9	58	60.0	36.8	61	30-130
Nitrobenzene-d5	20.0	15.2	76	20.0	16.1	80	40-130
Phenol-d5	60.0	42.1	70	60.0	44.5	74	30-130
Terphenyl-d14	20.0	13.7	68	20.0	14.3	71	50-130

SW1311/3520C/8270C
TCLP SEMI VOLATILE ORGANICS BY GC/MS

Client : PUNA GEOTHERMAL VENTURE	Date Collected: NA
Project : PUNA GEOTHERMAL VENTURE	Date Received: 01/22/18
Batch No. : 18A178	Date Extracted: 01/22/18 14:30
Sample ID: MBLK2W	Date Analyzed: 01/24/18 17:24
Lab Samp ID: TXA011WB	Dilution Factor: 10
Lab File ID: RAJ339	Matrix : LEACHATE
Ext Btch ID: SVA025W	% Moisture : NA
Calib. Ref.: RFJ007	Instrument ID : T-OE4

PARAMETERS	RESULTS (ug/L)	RL (ug/L)	MDL (ug/L)
2,4,5-TRICHLOROPHENOL	ND	100	50
2,4,6-TRICHLOROPHENOL	ND	100	50
2,4-DINITROTOLUENE	ND	100	50
O-CRESOL	ND	100	50
P-CRESOL (1)	ND	100	50
HEXACHLOROBENZENE	ND	100	50
HEXACHLORO-1,3-BUTADIENE	ND	100	50
HEXACHLOROETHANE	ND	100	50
NITROBENZENE	ND	100	50
PYRIDINE	ND	400	200

SURROGATE PARAMETERS	RESULTS	SPK_AMT	% RECOVERY	QC LIMIT
2,4,6-TRIBROMOPHENOL	488	600.0	81.3	40-140
2-FLUOROBIPHENYL	175	200.0	87.6	40-130
2-FLUOROPHENOL	397	600.0	66.2	30-130
NITROBENZENE-D5	173	200.0	86.7	40-130
PHENOL-D5	463	600.0	77.1	30-130
TERPHENYL-D14	153	200.0	76.7	50-130

(1): Cannot be separated from m-Cresol
DateTime Leached: 01/19/18 12:00

LABORATORY REPORT FOR

PUNA GEOTHERMAL VENTURE

PUNA GEOTHERMAL VENTURE

TCLP
METALS / MERCURY

SDG#: 18A178

CASE NARRATIVE

Client : PUNA GEOTHERMAL VENTURE

Project: PUNA GEOTHERMAL VENTURE

SDG : 18A178

METHOD 1311/SW3010A/SW6010B
TCLP METALS BY ICP

One (1) water sample was received on 01/17/18 to be analyzed for TCLP Metals by ICP in accordance with Method 1311/SW3010A/SW6010B and project specific requirements.

Holding Time
The sample was digested and analyzed within the prescribed holding time.

Calibration
Initial Calibration was established as prescribed by the method and was verified using a secondary source (ICV). Interference checks were performed and results were within required limits. Continuing calibration verifications and continuing calibration blanks were carried out at the frequency specified by the project. Samples associated with one or more analytes that were not CCV/CCB compliant were re-analyzed. All calibration requirements were satisfied.

Method Blank
Method blank was prepared and analyzed at the frequency required by the project. For this SDG, two (2) method blanks were analyzed. IPA020WB and TXA011WB were compliant to project requirement. Refer to sample result summary forms for details.

Lab Control Sample
Lab control sample was prepared and analyzed at a frequency required by the project. For this SDG, one (1) set of LCS/LCD was analyzed. IPA020WL/IPA020WC were within LCS limits. Refer to LCS summary form for details.

Matrix QC Sample
Matrix spike sample was prepared and analyzed at a frequency required by the project. For this SDG, one (1) set of MS/MSD was analyzed and the following was noted: A178-01M/A178-01S - Percent recovery for Selenium was not within MS/MSD QC limits. Presence of matrix interference was suspected. The rest of the analytes were in control. Analytical spike and serial dilution were analyzed and evaluated as appropriate. Results were within expected values. Refer to Matrix QC summary form for details.

Sample Analysis
The sample was analyzed according to prescribed analytical procedures. Results were evaluated in accordance to project requirements. For this SDG, all quality control requirements were met with the exception of those that were discussed within the associated QC parameter.

LAB CHRONICLE
TCLP METALS BY ICP

Client	: PUNA GEOTHERMAL VENTURE	SDG NO.	: 18A178
Project	: PUNA GEOTHERMAL VENTURE	Instrument ID	: ID8

WATER

Client Sample ID	Laboratory Sample ID	Dilution Factor	% Moist	Analysis DateTime	Extraction DateTime	Sample Data FN	Calibration Data FN	Prep. Batch	Notes
MBLK1W	IPA020WB	1.000	NA	01/29/1817:22	01/23/1811:38	ID8A019044	ID8A019042	IPA020W	Method Blank
LCS1W	IPA020WL	1.000	NA	01/29/1817:26	01/23/1811:38	ID8A019045	ID8A019042	IPA020W	Lab Control Sample (LCS)
LCD1W	IPA020WC	1.000	NA	01/29/1817:30	01/23/1811:38	ID8A019046	ID8A019042	IPA020W	LCS Duplicate
MBLK2W	TXA011WB	1.000	NA	01/29/1819:04	01/23/1811:38	ID8A019070	ID8A019068	IPA020W	Method Blank
TYPE 3 & 4 INJECTATEMS	A178-01M	1.000	NA	01/29/1819:12	01/23/1811:38	ID8A019072	ID8A019068	IPA020W	Matrix Spike Sample (MS)
TYPE 3 & 4 INJECTATEMSD	A178-01S	1.000	NA	01/29/1819:15	01/23/1811:38	ID8A019073	ID8A019068	IPA020W	MS Duplicate (MSD)
TYPE 3 & 4 INJECTATE	A178-01A	1.000	NA	01/29/1819:19	01/23/1811:38	ID8A019074	ID8A019068	IPA020W	Analytical Spike Sample
TYPE 3 & 4 INJECTATE	A178-01N	1.000	NA	01/29/1819:23	01/23/1811:38	ID8A019075	ID8A019068	IPA020W	Field Sample
TYPE 3 & 4 INJECTATE	A178-01J	5.000	NA	01/29/1819:26	01/23/1811:38	ID8A019076	ID8A01906B	IPA020W	Diluted Sample

FN - Filename
% Moist - Percent Moisture

METHOD 1311/SW3010A/SW6010B
TCLP METALS BY ICP

Client : PUNA GEOTHERMAL VENTURE	Date Collected: 01/15/18 10:15
Project : PUNA GEOTHERMAL VENTURE	Date Received: 01/17/18
SDG NO. : 18A178	Date Extracted: 01/23/18 11:38
Sample ID: TYPE 3 & 4 INJECTATE	Date Analyzed: 01/29/18 19:23
Lab Samp ID: A178-01N	Dilution Factor: 1
Lab File ID: ID8A019075	Matrix: LEACHATE
Ext Btch ID: IPA020W	% Moisture: NA
Calib. Ref.: ID8A019068	Instrument ID: D8

PARAMETERS	Result (mg/L)	RL (mg/L)	MDL (mg/L)
Arsenic	0.0618	0.0500	0.0250
Barium	3.30	0.0500	0.0100
Cadmium	ND	0.0500	0.0100
Chromium	ND	0.0500	0.0150
Lead	ND	0.0500	0.0150
Selenium	ND	0.0500	0.0250
Silver	ND	0.0500	0.0150

Note: Detection limits are reported relative to sample result significant figures.

Sample Amount : 10ml　　Final Volume:50ml
Prepared by : SPara　　Analyzed by:MRomer/MCand
DateTime Leached: 01/19/18 12:00

METHOD 1311/SW3010A/SW6010B
TCLP METALS BY ICP

Client	: PUNA GEOTHERMAL VENTURE	Date Collected:	NA
Project	: PUNA GEOTHERMAL VENTURE	Date Received:	NA
SDG NO.	: 18A178	Date Extracted:	01/23/18 11:38
Sample ID:	MBLK1W	Date Analyzed:	01/29/18 17:22
Lab Samp ID:	IPA020WB	Dilution Factor:	1
Lab File ID:	ID8A019044	Matrix:	WATER
Ext Btch ID:	IPA020W	% Moisture:	NA
Calib. Ref.:	ID8A019042	Instrument ID:	D8

PARAMETERS	Result (mg/L)	RL (mg/L)	MDL (mg/L)
Arsenic	ND	0.0100	0.00500
Barium	ND	0.0100	0.00200
Cadmium	ND	0.0100	0.00200
Chromium	ND	0.0100	0.00300
Lead	ND	0.0100	0.00300
Selenium	ND	0.0100	0.00500
Silver	ND	0.0100	0.00300

Note: Detection limits are reported relative to sample result significant figures.

Sample Amount : 50ml Final Volume:50ml

Prepared by : SPara Analyzed by:MRomer/MCand

EMAX QUALITY CONTROL DATA
LAB CONTROL SAMPLE ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : PUNA GEOTHERMAL VENTURE
BATCH NO. : 18A178
METHOD : 1311/SW3010A/SW6010B

MATRIX	: WATER		% MOISTURE:NA
DILUTION FACTOR:	1.000	1.000	1.000
SAMPLE ID	: MBLK1W	LCS1W	LCD1W
LAB SAMPLE ID	: IPA020WB	IPA020WL	IPA020WC
LAB FILE ID	: ID8A019044	ID8A019045	ID8A019046
DATE PREPARED	: 01/23/18 11:38	01/23/18 11:38	01/23/18 11:38
DATE ANALYZED	: 01/29/18 17:22	01/29/18 17:26	01/29/18 17:30
PREP BATCH	: IPA020W	IPA020W	IPA020W
CALIBRATION REF:	ID8A019042	ID8A019042	ID8A019042

ACCESSION:

PARAMETERS	MBResult (mg/L)	SpikeAmt (mg/L)	LCSResult (mg/L)	LCSRec (%)	SpikeAmt (mg/L)	LCDResult (mg/L)	LCDRec (%)	RPD (%)	QCLimit (%)	MaxRPD (%)
Arsenic	ND	0.5	0.496	99	0.5	0.480	96	3	80-120	20
Barium	ND	0.5	0.503	101	0.5	0.490	98	3	80-120	20
Cadmium	ND	0.5	0.504	101	0.5	0.488	98	3	80-120	20
Chromium	ND	0.5	0.496	99	0.5	0.497	99	0	80-120	20
Lead	ND	0.5	0.477	95	0.5	0.477	95	0	80-120	20
Selenium	ND	0.5	0.503	101	0.5	0.485	97	4	80-120	20
Silver	ND	0.5	0.465	93	0.5	0.454	91	2	80-120	20

METHOD 1311/SW3010A/SW6010B
TCLP METALS BY ICP

Client : PUNA GEOTHERMAL VENTURE	Date Collected: NA
Project : PUNA GEOTHERMAL VENTURE	Date Received: NA
SDG NO. : 18A178	Date Extracted: 01/23/18 11:38
Sample ID: MBLK2W	Date Analyzed: 01/29/18 19:04
Lab Samp ID: TXA011WB	Dilution Factor: 1
Lab File ID: ID8A019070	Matrix: LEACHATE
Ext Btch ID: IPA020W	% Moisture: NA
Calib. Ref.: ID8A019068	Instrument ID: D8

PARAMETERS	Result (mg/L)	RL (mg/L)	MDL (mg/L)
Arsenic	ND	0.0500	0.0250
Barium	ND	0.0500	0.0100
Cadmium	ND	0.0500	0.0100
Chromium	ND	0.0500	0.0150
Lead	ND	0.0500	0.0150
Selenium	ND	0.0500	0.0250
Silver	ND	0.0500	0.0150

Note: Detection limits are reported relative to sample result significant figures.
Sample Amount : 10ml Final Volume:50ml
Prepared by : SPara Analyzed by:MRomer/MCand
DateTime Leached: 01/19/18 12:00

EMAX QUALITY CONTROL DATA
MS/MSD ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : PUNA GEOTHERMAL VENTURE
BATCH NO. : 18A178
METHOD : 1311/SW3010A/SW6010B

MATRIX	: LEACHATE		% MOISTURE: NA
DILUTION FACTOR	: 1	1	1
SAMPLE ID	: TYPE 3 & 4 INJECTATE	TYPE 3 & 4 INJECTATEMS	TYPE 3 & 4 INJECTATEMSD
LAB SAMPLE ID	: A178-01N	A178-01M	A178-01S
LAB FILE ID	: ID8A019075	ID8A019072	ID8A019073
DATE PREPARED	: 01/23/18 11:38	01/23/18 11:38	01/23/18 11:38
DATE ANALYZED	: 01/29/18 19:23	01/29/18 19:12	01/29/18 19:15
PREP BATCH	: IPA020W	IPA020W	IPA020W
CALIBRATION REF	: ID8A019068	ID8A019068	ID8A019068

ACCESSION:

PARAMETERS	PSResult (mg/L)	SpikeAmt (mg/L)	MSResult (mg/L)	MSRec (%)	SpikeAmt (mg/L)	MSDResult (mg/L)	MSDRec (%)	RPD (%)	QCLimit (%)	MaxRPD (%)
Arsenic	0.0618	2.5	2.54	99.1	2.5	2.38	92.7	7	75-125	20
Barium	3.30	2.5	5.63	93.2	2.5	5.26	78.4	7	75-125	20
Cadmium	ND	2.5	2.37	94.8	2.5	2.20	88.0	7	75-125	20
Chromium	ND	2.5	2.50	100	2.5	2.35	94.0	6	75-125	20
Lead	ND	2.5	2.39	95.6	2.5	2.25	90.0	6	75-125	20
Selenium	ND	2.5	1.15	46.0*	2.5	1.04	41.6*	10	75-125	20
Silver	ND	2.5	2.30	92.0	2.5	2.13	85.2	8	75-125	20

PSResult - Parent Sample Result
* Out of QC limit

EMAX QUALITY CONTROL DATA
SERIAL DILUTION ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : PUNA GEOTHERMAL VENTURE
BATCH NO. : 18A178
METHOD : 1311/SW3010A/SW6010B

MATRIX	: LEACHATE	% MOISTURE: NA
DILUTION FACTOR	: 1	5
SAMPLE ID	: TYPE 3 & 4 INJECTATE	TYPE 3 & 4 INJECTATE
LAB SAMPLE ID	: A178-01N	A178-01J
LAB FILE ID	: ID8A019075	ID8A019076
DATE PREPARED	: 01/23/18 11:38	01/23/18 11:38
DATE ANALYZED	: 01/29/18 19:23	01/29/18 19:26
PREP BATCH	: IPA020W	IPA020W
CALIBRATION REF	: ID8A019068	ID8A019068

ACCESSION:

PARAMETERS	Sample Result (mg/L)	SD Result (mg/L)	%Difference (%)	Max %D (%)
Arsenic	0.0618	ND	NA	10
Barium	3.30	3.56	8	10
Cadmium	ND	ND	0	10
Chromium	ND	ND	0	10
Lead	ND	ND	0	10
Selenium	ND	ND	0	10
Silver	ND	ND	0	10

SD - Serial Dilution

EMAX QUALITY CONTROL DATA
ANALYTICAL SPIKE ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : PUNA GEOTHERMAL VENTURE
BATCH NO. : 18A178
METHOD : 1311/SW3010A/SW6010B

MATRIX	: LEACHATE	% MOISTURE: NA
DILUTION FACTOR:	1	1
SAMPLE ID	: TYPE 3 & 4 INJECTATE	TYPE 3 & 4 INJECTATE
LAB SAMPLE ID	: A178-01N	A178-01A
LAB FILE ID	: ID8A019075	ID8A019074
DATE PREPARED	: 01/23/18 11:38	01/23/18 11:38
DATE ANALYZED	: 01/29/18 19:23	01/29/18 19:19
PREP BATCH	: IPA020W	IPA020W
CALIBRATION REF:	ID8A019068	ID8A019068

ACCESSION:

PARAMETERS	Sample Result (mg/L)	Spike Amt (mg/L)	AS Result (mg/L)	AS Rec (%)	QC Limit (%)
Arsenic	0.0618	2.5	2.89	113	75-125
Barium	3.30	2.5	5.93	105	75-125
Cadmium	ND	2.5	2.58	103	75-125
Chromium	ND	2.5	2.79	112	75-125
Lead	ND	2.5	2.71	108	75-125
Selenium	ND	2.5	2.77	111	75-125
Silver	ND	2.5	2.90	116	75-125

AS - Analytical Spike

CASE NARRATIVE

Client : PUNA GEOTHERMAL VENTURE

Project: PUNA GEOTHERMAL VENTURE

SDG : 18A178

METHOD 1311/SW7470A
TCLP MERCURY

One (1) water sample was received on 01/17/18 to be analyzed for TCLP Mercury in accordance with Method 1311/SW7470A and project specific requirements.

Holding Time
The sample was digested and analyzed within the prescribed holding time.

Calibration
Multi-calibration points were generated to establish initial calibration (ICAL). ICAL was verified using a secondary source (ICV). Continuing calibration (CCV) verifications were carried out on a frequency specified by the project. All calibration requirements were within acceptance criteria.

Method Blank
Method blank was prepared and analyzed at the frequency required by the project. For this SDG, two (2) method blanks were analyzed. HGA013WB and TXA011WB were compliant to project requirement. Refer to sample result summary forms for details.

Lab Control Sample
Lab control sample was prepared and analyzed at a frequency required by the project. For this SDG, one (1) set of LCS/LCD was analyzed. HGA013WL/HGA013WC were within LCS limits. Refer to LCS summary form for details.

Matrix QC Sample
Matrix spike sample was prepared and analyzed at a frequency required by the project. For this SDG, one (1) set of MS/MSD was analyzed. Mercury was within MS QC limits in A178-01M/A178-01S. Refer to Matrix QC summary form for details.

Sample Analysis
The sample was analyzed according to prescribed analytical procedures. Results were evaluated in accordance to project requirements. For this SDG, all quality control requirements were met.

LAB CHRONICLE
TCLP MERCURY

Client : PUNA GEOTHERMAL VENTURE
Project : PUNA GEOTHERMAL VENTURE

SDG NO. : 18A178
Instrument ID : 47

WATER

Client Sample ID	Laboratory Sample ID	Dilution Factor	% Moist	Analysis DateTime	Extraction DateTime	Sample Data FN	Calibration Data FN	Prep. Batch	Notes
MBLK1W	HGA013WB	1	NA	01/22/1820:40	01/22/1814:45	M47A011037	M47A011	18HGA013WW	Method Blank
LCS1W	HGA013WL	1	NA	01/22/1820:42	01/22/1814:45	M47A011038	M47A011	18HGA013WW	Lab Control Sample (LCS)
LCD1W	HGA013WC	1	NA	01/22/1820:44	01/22/1814:45	M47A011039	M47A011	18HGA013WW	LCS Duplicate
MBLK2W	TXA011WB	1	NA	01/22/1821:17	01/22/1814:45	M47A011055	M47A011	18HGA013WW	Method Blank
TYPE 3 & 4 INJECTATE	A178-01	1	NA	01/22/1821:24	01/22/1814:45	M47A011059	M47A011	18HGA013WW	Field Sample
TYPE 3 & 4 INJECTATEMS	A178-01M	1	NA	01/22/1821:28	01/22/1814:45	M47A011061	M47A011	18HGA013WW	Matrix Spike Sample (MS)
TYPE 3 & 4 INJECTATEMSD	A178-01S	1	NA	01/22/1821:30	01/22/1814:45	M47A011062	M47A011	18HGA013WW	MS Duplicate (MSD)

FN - Filename
% Moist - Percent Moisture

METHOD 1311/SW7470A
TCLP MERCURY

Client : PUNA GEOTHERMAL VENTURE
Project : PUNA GEOTHERMAL VENTURE
Batch No. : 18A178

Matrix : LEACHATE
InstrumentID : 47

CLIENT SAMPLE ID	EMAX SAMPLE ID	RESULTS (ug/L)	DILT'N FACTOR	MOIST (%)	RL (ug/L)	MDL (ug/L)	ANALYSIS DATETIME	PREPARATION DATETIME	DATA FILE ID	CAL REF	PREP BATCH	COLLECTION DATETIME	RECEIVED DATETIME
MBLK1W	HGA013WB	ND	1	NA	0.500	0.100	01/22/1820:40	01/22/1814:45	M47A011037	M47A011	18HGA013W	NA	NA
LCS1W	HGA013WL	2.55	1	NA	0.500	0.100	01/22/1820:42	01/22/1814:45	M47A011038	M47A011	18HGA013W	NA	NA
LCD1W	HGA013WC	2.50	1	NA	0.500	0.100	01/22/1820:44	01/22/1814:45	M47A011039	M47A011	18HGA013W	NA	NA
MBLK2W	TXA011WB	ND	1	NA	5.00	1.00	01/22/1821:17	01/22/1814:45	M47A011055	M47A011	18HGA013W	NA	NA
TYPE 3 & 4 INJECTATE	A178-01	ND	1	NA	5.00	1.00	01/22/1821:24	01/22/1814:45	M47A011059	M47A011	18HGA013W	01/15/1810:15	01/17/18
TYPE 3 & 4 INJECTATEMS	A178-01M	25.7	1	NA	5.00	1.00	01/22/1821:28	01/22/1814:45	M47A011061	M47A011	18HGA013W	01/15/1810:15	01/17/18
TYPE 3 & 4 INJECTATEMSD	A178-01S	24.3	1	NA	5.00	1.00	01/22/1821:30	01/22/1814:45	M47A011062	M47A011	18HGA013W	01/15/1810:15	01/17/18

Note: Detection limits are reported relative to sample result significant figures.

DateTime Leached: 01/19/18 12:00
Note: 5 ml leachate was diluted to 50 ml reagent water prior to digestion.

EMAX QUALITY CONTROL DATA
LAB CONTROL SAMPLE ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : PUNA GEOTHERMAL VENTURE
BATCH NO. : 18A178
METHOD : METHOD 1311/SW7470A

MATRIX	: WATER		% MOISTURE:NA
DILUTION FACTOR:	1	1	1
SAMPLE ID	: MBLK1W	LCS1W	LCD1W
LAB SAMPLE ID	: HGA013WB	HGA013WL	HGA013WC
LAB FILE ID	: M47A011037	M47A011038	M47A011039
DATE PREPARED	: 01/22/1814:45	01/22/1814:45	01/22/1814:45
DATE ANALYZED	: 01/22/1820:40	01/22/1820:42	01/22/1820:44
PREP BATCH	: 18HGA013W	18HGA013W	18HGA013W
CALIBRATION REF:	M47A011	M47A011	M47A011

ACCESSION:

PARAMETERS	MBResult (ug/L)	SpikeAmt (ug/L)	LCSResult (ug/L)	LCSRec (%)	SpikeAmt (ug/L)	LCDResult (ug/L)	LCDRec (%)	RPD (%)	QCLimit (%)	MaxRPD (%)
Mercury	ND	2.50	2.55	102	2.50	2.50	100	2	80-120	20

MB: Method Blank sample LCS: Lab Control Sample LCD: Lab Control Sample Duplicate

EMAX QUALITY CONTROL DATA
MS/MSD ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : PUNA GEOTHERMAL VENTURE
BATCH NO. : 18A178
METHOD : METHOD 1311/SW7470A

MATRIX	: LEACHATE		% MOISTURE:NA
DILUTION FACTOR:	1	1	1
SAMPLE ID	: TYPE 3 & 4 INJECTATE	TYPE 3 & 4 INJECTATEMS	TYPE 3 & 4 INJECTATEMSD
LAB SAMPLE ID	: A178-01	A178-01M	A178-01S
LAB FILE ID	: M47A011059	M47A011061	M47A011062
DATE PREPARED	: 01/22/1814:45	01/22/1814:45	01/22/1814:45
DATE ANALYZED	: 01/22/1821:24	01/22/1821:28	01/22/1821:30
PREP BATCH	: 18HGA013W	18HGA013W	18HGA013W
CALIBRATION REF:	M47A011	M47A011	M47A011

ACCESSION:

PARAMETERS	PSResult (ug/L)	SpikeAmt (ug/L)	MSResult (ug/L)	MSRec (%)	SpikeAmt (ug/L)	MSDResult (ug/L)	MSDRec (%)	RPD (%)	QCLimit (%)	MaxRPD (%)
Mercury	ND	25.0	25.7	103	25.0	24.3	97.2	6	75-125	20

PS: Parent Sample MS: Matrix Spike MSD: Matrix Spike Duplicate

LABORATORY REPORT FOR

PUNA GEOTHERMAL VENTURE

PUNA GEOTHERMAL VENTURE

WET CHEMICAL ANALYSES

SDG#: 18A178

CASE NARRATIVE

Client : PUNA GEOTHERMAL VENTURE

Project: PUNA GEOTHERMAL VENTURE

SDG : 18A178

METHOD SW1010
IGNITABILITY

One (1) water sample was received on 01/17/18 to be analyzed for Ignitability in accordance with Method SW1010 and project specific requirements.

Holding Time
The sample was analyzed within the prescribed holding time.

Calibration
Calibration was performed as specified by the method. All calibration requirements were within acceptance criteria.

Lab Control Sample
Lab control sample was prepared and analyzed at a frequency required by the project. For this SDG, one (1) LCS was analyzed. Percent recovery for Ignitability was within LCS QC limits in IGA002L. Refer to LCS summary form for details.

Matrix QC Sample
Sample duplicate was analyzed and RPD was within expected value.

Sample Analysis
The sample was analyzed according to prescribed analytical procedures. Results were evaluated in accordance to project requirements. For this SDG, all quality control requirements were met.

METHOD SW1010
IGNITABILITY

Client : PUNA GEOTHERMAL VENTURE
Project : PUNA GEOTHERMAL VENTURE
Batch No. : 18A178

Matrix : WATER
InstrumentID : 28

CLIENT SAMPLE ID	EMAX SAMPLE ID	RESULTS (oC)	PREP FACTOR	MOIST (%)	RL (oC)	MDL (oC)	ANALYSIS DATETIME	PREPARATION DATETIME	DATA FILE ID	CAL REF	PREP BATCH	COLLECTION DATETIME	RECEIVED DATETIME
LCS1	IGA002L	50.9	1	NA	25	25	01/22/1811:43	NA	18IGA00201	18IGA002	IGA002	NA	NA
TYPE 3 & 4 INJECTATE	A178-01	100>	1	NA	25	25	01/22/1812:48	NA	18IGA00204	18IGA002	IGA002	01/15/1810:15	01/17/18
TYPE 3 & 4 INJECTATEDUP	A178-01D	100>	1	NA	25	25	01/22/1813:01	NA	18IGA00205	18IGA002	IGA002	01/15/1810:15	01/17/18

> : No flash at 100 degrees C

EMAX QUALITY CONTROL DATA
LCS ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : PUNA GEOTHERMAL VENTURE
BATCH NO. : 18A178
METHOD : SW1010

MATRIX	: N-DECANE	
DILUTION FACTOR:	NA	1
SAMPLE ID	: NA	LCS1
LAB SAMPLE ID	: NA	IGA002L
LAB FILE ID	: NA	18IGA00201
DATE PREPARED	: NA	01/22/1811:43
DATE ANALYZED	: NA	01/22/1811:43
PREP BATCH	: NA	IGA002
CALIBRATION REF:	NA	18IGA002

ACCESSION:

PARAMETER	MB RESULT (oC)	EXPECTED (oC)	LCS RESULT (oC)	DIFF (oC)	QC LIMIT (oC)
IGNITABILITY	NA	51.2	50.9	-0.30	48.9-53.5

EMAX QUALITY CONTROL DATA
SAMPLE DUPLICATE ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : PUNA GEOTHERMAL VENTURE
BATCH NO. : 18A178
METHOD : SW1010

MATRIX	: WATER	
DILUTION FACTOR:	1	1
SAMPLE ID	: TYPE 3 & 4 INJECTATE	TYPE 3 & 4 INJECTATEDUP
LAB SAMPLE ID	: A178-01	A178-01D
LAB FILE ID	: 18IGA00204	18IGA00205
DATE PREPARED	: NA	NA
DATE ANALYZED	: 01/22/1812:48	01/22/1813:01
PREP BATCH	: IGA002	IGA002
CALIBRATION REF:	18IGA002	18IGA002

ACCESSION:

PARAMETER	PARENT RESULT (oC)	DUP RESULT (oC)	DIFFERENCE (oC)	MAX DIFF. (oC)
IGNITABILITY	100>	100>	0	2

>: No flash at 100 degrees C

CASE NARRATIVE

Client : PUNA GEOTHERMAL VENTURE

Project: PUNA GEOTHERMAL VENTURE

SDG : 18A178

SW846 CHAPTER 7.3
REACTIVE CYANIDE

One (1) water sample was received on 01/17/18 to be analyzed for Reactive Cyanide in accordance with SW846 Chapter 7.3 and project specific requirements.

Holding Time
The sample was analyzed within the prescribed holding time.

Calibration
Calibration was performed as prescribed by the method and was verified using a secondary source (ICV). All calibration requirements were within acceptance criteria.

Method Blank
Method blank was prepared and analyzed at the frequency required by the project. For this SDG, one (1) method blank was analyzed. Reactive Cyanide was not detected in RCA002WB. Refer to sample result summary form for details.

Lab Control Sample
Lab control sample was prepared and analyzed at a frequency required by the project. For this SDG, one (1) set of LCS/LCD was analyzed. RCA002WL/RCA002WC - Percent recovery for Reactive Cyanide was within LCS/LCD QC limits. Refer to LCS summary form for details.

Matrix QC Sample
Sample duplicate was analyzed and RPD was within expected value.

Sample Analysis
The sample was analyzed according to prescribed analytical procedures. Results were evaluated in accordance to project requirements. For this SDG, all quality control requirements were met.

METHOD CHAPTER 7.3/SW846
REACTIVE CYANIDE

Client : PUNA GEOTHERMAL VENTURE
Project : PUNA GEOTHERMAL VENTURE
Batch No. : 18A178

Matrix : WATER
InstrumentID : 70

CLIENT SAMPLE ID	EMAX SAMPLE ID	RESULTS (mg/L)	DFxPREP FACTOR	MOIST (%)	RL (mg/L)	MDL (mg/L)	ANALYSIS DATETIME	PREPARATION DATETIME	DATA FILE ID	CAL REF	PREP BATCH	COLLECTION DATETIME	RECEIVED DATETIME
MBLK1W	RCA002WB	ND	1	NA	0.02	0.01	01/25/1818:12	01/22/1814:00	18RCA00210	18RCA002	RCA002W	NA	NA
LCS1W	RCA002WL	0.632	1	NA	0.02	0.01	01/25/1818:13	01/22/1814:00	18RCA00211	18RCA002	RCA002W	NA	NA
LCD1W	RCA002WC	0.625	1	NA	0.02	0.01	01/25/1818:13	01/22/1814:00	18RCA00212	18RCA002	RCA002W	NA	NA
TYPE 3 & 4 INJECTATE	A178-01	ND	1	NA	0.02	0.01	01/25/1818:13	01/22/1814:00	18RCA00215	18RCA002	RCA002W	01/15/1810:15	01/17/18
TYPE 3 & 4 INJECTATEDUP	A178-01D	ND	1	NA	0.02	0.01	01/25/1818:13	01/22/1814:00	18RCA00216	18RCA002	RCA002W	01/15/1810:15	01/17/18

EMAX QUALITY CONTROL DATA
LAB CONTROL SAMPLE ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : PUNA GEOTHERMAL VENTURE
BATCH NO. : 18A178
METHOD : CHAPTER 7.3/SW846

MATRIX	: WATER		% MOISTURE:NA
DILUTION FACTOR:	1	1	1
SAMPLE ID	: MBLK1W	LCS1W	LCD1W
LAB SAMPLE ID	: RCA002WB	RCA002WL	RCA002WC
LAB FILE ID	: 18RCA00210	18RCA00211	18RCA00212
DATE PREPARED	: 01/22/1814:00	01/22/1814:00	01/22/1814:00
DATE ANALYZED	: 01/25/1818:12	01/25/1818:13	01/25/1818:13
PREP BATCH	: RCA002W	RCA002W	RCA002W
CALIBRATION REF:	18RCA002	18RCA002	18RCA002

ACCESSION:

PARAMETERS	MBResult (mg/L)	SpikeAmt (mg/L)	LCSResult (mg/L)	LCSRec (%)	SpikeAmt (mg/L)	LCDResult (mg/L)	LCDRec (%)	RPD (%)	QCLimit (%)	MaxRPD (%)
Reactive Cyanide	ND	2.48	0.632	26	2.48	0.625	25	1	5-120	20

MB: Method Blank sample LCS: Lab Control Sample LCD: Lab Control Sample Duplicate
* Out of QC criteria

EMAX QUALITY CONTROL DATA
SAMPLE DUPLICATE ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : PUNA GEOTHERMAL VENTURE
BATCH NO. : 18A178
METHOD : CHAPTER 7.3/SW846

MATRIX	: WATER	
DILUTION FACTOR:	1	1
SAMPLE ID	: TYPE 3 & 4 INJECTATE	TYPE 3 & 4 INJECTATEDUP
LAB SAMPLE ID	: A178-01	A178-01D
LAB FILE ID	: 18RCA00215	18RCA00216
DATE PREPARED	: 01/22/1814:00	01/22/1814:00
DATE ANALYZED	: 01/25/1818:13	01/25/1818:13
PREP BATCH	: RCA002W	RCA002W
CALIBRATION REF:	18RCA002	18RCA002

ACCESSION:

PARAMETER	PSResult (mg/L)	DUPResult (mg/L)	RPD (%)	QCLimit (%)
Reactive Cyanide	ND	ND	0	20

PS: Parent Sample DUP: Sample Duplicate

CASE NARRATIVE

Client : PUNA GEOTHERMAL VENTURE

Project: PUNA GEOTHERMAL VENTURE

SDG : 18A178

SW846 CHAPTER 7.3
REACTIVE SULFIDE

One (1) water sample was received on 01/17/18 to be analyzed for Reactive Sulfide in accordance with SW846 Chapter 7.3 and project specific requirements.

Holding Time
The sample was analyzed within the prescribed holding time.

Method Blank
Method blank was prepared and analyzed at the frequency required by the project. For this SDG, one (1) method blank was analyzed. Reactive Sulfide was not detected in RSA002WB. Refer to sample result summary form for details.

Lab Control Sample
Lab control sample was prepared and analyzed at a frequency required by the project. For this SDG, one (1) set of LCS/LCD was analyzed. RSA002WL/RSA002WC were within LCS limits. Refer to LCS summary form for details.

Matrix QC Sample
Sample duplicate was analyzed and RPD was within expected value.

Sample Analysis
The sample was analyzed according to prescribed analytical procedures. Results were evaluated in accordance to project requirements. For this SDG, all quality control requirements were met.

METHOD CHAPTER 7.3/SW846
REACTIVE SULFIDE

Client : PUNA GEOTHERMAL VENTURE
Project : PUNA GEOTHERMAL VENTURE
Batch No. : 18A178

Matrix : WATER
InstrumentID : NA

CLIENT SAMPLE ID	EMAX SAMPLE ID	RESULTS (mg/L)	PREP. FACTOR	MOIST (%)	RL (mg/L)	MDL (mg/L)	ANALYSIS DATETIME	PREPARATION DATETIME	DATA FILE ID	CAL REF	PREP BATCH	COLLECTION DATETIME	RECEIVED DATETIME
MBLK1W	RSA002WB	ND	1.00	NA	.5	.2	01/25/1818:54	01/22/1814:50	18RSA00201	18RSA002	RSA002W	NA	NA
LCS1W	RSA002WL	3.56	1.00	NA	.5	.2	01/25/1818:57	01/22/1814:50	18RSA00202	18RSA002	RSA002W	NA	NA
LCD1W	RSA002WC	3.24	1.00	NA	.5	.2	01/25/1819:00	01/22/1814:50	18RSA00203	18RSA002	RSA002W	NA	NA
TYPE 3 & 4 INJECTATE	A178-01	30.4	1.00	NA	.5	.2	01/25/1819:07	01/22/1814:50	18RSA00206	18RSA002	RSA002W	01/15/1810:15	01/17/18
TYPE 3 & 4 INJECTATEDUP	A178-01D	29.6	1.00	NA	.5	.2	01/25/1819:09	01/22/1814:50	18RSA00207	18RSA002	RSA002W	01/15/1810:15	01/17/18

EMAX QUALITY CONTROL DATA
LAB CONTROL SAMPLE ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : PUNA GEOTHERMAL VENTURE
BATCH NO. : 18A178
METHOD : METHOD CHAPTER 7.3/SW846

MATRIX	: WATER			% MOISTURE: NA
DILUTION FACTOR:	1	1	1	
SAMPLE ID	: MBLK1W	LCS1W	LCD1W	
LAB SAMPLE ID	: RSA002WB	RSA002WL	RSA002WC	
LAB FILE ID	: 18RSA00201	18RSA00202	18RSA00203	
DATE EXTRACTED	: NA	NA	NA	
DATE ANALYZED	: 01/25/1818:54	01/25/1818:57	01/25/1819:00	
PREP BATCH	: RSA002W	RSA002W	RSA002W	
CALIBRATION REF:				

ACCESSION:

PARAMETER	MB RESULT (mg/L)	SPIKE AMT (mg/L)	BS RESULT (mg/L)	BS REC (%)	SPIKE AMT (mg/L)	BSD RESULT (mg/L)	BSD REC (%)	RPD (%)	QC LIMIT (%)	MAX RPD (%)
Reactive Sulfide	ND	3.98	3.56	89	3.98	3.24	81	9	30-120	20

EMAX QUALITY CONTROL DATA
SAMPLE DUPLICATE ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : PUNA GEOTHERMAL VENTURE
BATCH NO. : 18A178
METHOD : METHOD CHAPTER 7.3/SW846

MATRIX	: WATER	
DILUTION FACTOR	: 1.00	1.00
SAMPLE ID	: TYPE 3 & 4 INJECTATE	TYPE 3 & 4 INJECTATEDUP
LAB SAMPLE ID	: A178-01	A178-01D
LAB FILE ID	: 18RSA00206	18RSA00207
DATE PREPARED	: 01/22/1814:50	01/22/1814:50
DATE ANALYZED	: 01/25/1819:07	01/25/1819:09
PREP BATCH	: RSA002W	RSA002W
CALIBRATION REF	: 18RSA002	18RSA002

ACCESSION:

PARAMETER	PARENT RESULT (mg/L)	DUP RESULT (mg/L)	RPD (%)	MAX RPD (%)
Reactive Sulfide	30.4	29.6	3	20

CASE NARRATIVE

Client : PUNA GEOTHERMAL VENTURE

Project: PUNA GEOTHERMAL VENTURE

SDG : 18A178

METHOD 9040B
PH

One (1) water sample was received on 01/17/18 to be analyzed for pH in accordance with Method 9040B and project specific requirements.

Holding Time
The sample was analyzed within the prescribed holding time.

Calibration
pH meter was calibrated per instrument operating manual instruction. Calibration was verified using a secondary source (ICV). Continuing calibration (CCV) verifications were carried out on a frequency specified by the project. All calibration requirements were within acceptance criteria.

Matrix QC Sample
Sample duplicate was analyzed and RPD was within expected value.

Sample Analysis
The sample was analyzed according to prescribed analytical procedures. Results were evaluated in accordance to project requirements. For this SDG, all quality control requirements were met.

METHOD 9040B
PH

Client : PUNA GEOTHERMAL VENTURE
Project : PUNA GEOTHERMAL VENTURE
Batch No. : 18A178

Matrix : WATER
InstrumentID : 53

CLIENT SAMPLE ID	EMAX SAMPLE ID	RESULTS (pH Unit)	DFxPREP FACTOR	MOIST (%)	RL (pH Unit)	MDL (pH Unit)	ANALYSIS DATETIME	PREPARATION DATETIME	DATA FILE ID	CAL REF	PREP BATCH	COLLECTION DATETIME	RECEIVED DATETIME
TYPE 3 & 4 INJECTATE	A178-01	4.31	1	NA	0.1	0.1	01/17/1817:09	NA	18PHA00801	18PHA008	PHA008W	01/15/1810:15	01/17/18
TYPE 3 & 4 INJECTATEDUP	A178-01D	4.32	1	NA	0.1	0.1	01/17/1817:11	NA	18PHA00802	18PHA008	PHA008W	01/15/1810:15	01/17/18

EMAX QUALITY CONTROL DATA
SAMPLE DUPLICATE ANALYSIS

CLIENT : PUNA GEOTHERMAL VENTURE
PROJECT : PUNA GEOTHERMAL VENTURE
BATCH NO. : 18A178
METHOD : 9040B

MATRIX	: WATER	
DILUTION FACTOR:	1	1
SAMPLE ID	: TYPE 3 & 4 INJECTATE	TYPE 3 & 4 INJECTATEDUP
LAB SAMPLE ID	: A178-01	A178-01D
LAB FILE ID	: 18PHA00801	18PHA00802
DATE PREPARED	: NA	NA
DATE ANALYZED	: 01/17/1817:09	01/17/1817:11
PREP BATCH	: PHA008W	PHA008W
CALIBRATION REF:	18PHA008	18PHA008

ACCESSION:

PARAMETER	ParentResult (pH Unit)	Dup_Result (pH Unit)	Difference (pH Unit)	Max Diff. (+/- pH Unit)
PH	4.31	4.32	.01	0.1

TABLE NO. 2
TEST PARAMETERS FOR TYPE III SAMPLE

Parameter	Regulatory Level	EPA Method
Ignitability	As described in 40 CFR (2012), Part 261.21	
Corrosivity	As described in 40 CFR (2012), Part 261.22	
Reactivity	As described in 40 CFR (2112), Part 26.23	
lnorganics:		
arsenic	5.0	
barium	100.0	
cadmium	1.0	
chromium	5.0	
lead	5.0	
mercury	0.2	
selenium	1.0	
silver	5.0	
Organics:		
benzene	0.5	
carbon tetrachloride	0.5	
chlorobenzene	100.0	Method 1311 (TCLP), with appropriate methods of analyses contained in SW-846
chloroform	6.0	
o-cresol	200.0	
m-cresol	200.0	
p-cresol	200.0	
1,4-dichlorobenzene	7.5	
1,2-dichloroethane	0.5	
1,1-dichloroethylene	0.7	
2,4-dinitrotoluene	0.13	
hexachlorobenzene	0.13	
hexachloro-1,3-butadiene	0.5	
hexachloroethane	3.0	
methyl ethyl ketone	200.0	
nitrobenzene	2.0	
pyridine	5.0	
tetrachloroethylene	0.7	
trichloroethylene	0.5	

2,4,5-trichlorophenol	400.0	
2,4,6-trichlorophenol	2.0	
vinyl chloride	0.2	

TABLE NO. 3
TEST PARAMETERS FOR TYPE IV SAMPLE

Methyl Ethyl Ketone			200.0
1,1,2,2-Tetrachloroethane			
Tetrachloroethene			
Toluene			
1,1,1-Trichloroethane			
1,1,2-Trichloroethane			
Trichloroethene			
Trichlorofluoromethane			
Vinyl Chloride			
Xylene			
Semi-Volatile Organics			
o-cresol			200 .0
m-cresol	8270		200.0
p-cresol			200.0
hexachlorobenzene			0.13
Semi-Volatile Organics			
2,4-dinitrotoluene			0.13
hexachloro-1,3-butadiene			0.5
hexachloroethane			3.0
nitrobenzene	8270		2.0
pyridine			5.0
2,4,5-trichlorophenol			400.0
2,4,6-trichlorophenol			2.0

Table H-2
INJECTION PRESSURE LIMITATIONS FOR EXISTING WELLS

Well Name	Depth to Deepest Cemented Csg Shoe Measured *(ft KB)*	Depth to Deepest Cemented Csg Shoe Vertical *(ft KB)*	Test Pressure Gradient (1) *(psi/ft)*	Injection Wellhead Pressure at Test Gradient (2) *(psig)*	Max Safe Injection Wellhead Pressure (3) *(psig)*	Gradient at Max Safe Wellhead Pressure *(psi/ft)*
KS-4 *	3,930	3,911	0.65	856	685	0.61
KS-3	3,897	3,888	0.65	851	500	0.56
KS-1A	4,061	4,044	0.65	884	500	0.56
KS-11	4,367	4,367	0.72	1,300	1,040	0.57
KS-11 **	4,873	4,766	0.63	919	735	0.59
KS-13	4,986	4,943	0.75	1,566	1,252	0.68
KS-15	3,901	3,855	0.64	806	645	0.60

(1) Measured test gradient in KS-4; inferred equal in KS-1A and KS-3.

(2) Injection wellhead pressure (at ground level) which results in pressure at casing shoe equal to test pressure at casing shoe. For this calculation, injectate is assumed to be 80 deg F water with 10,000 ppm TDS (.434 psi/ft), and flowing pressure losses in hangdown liner, casing and wellbore are neglected.

(3) For KS-4 and any additional wells this value is 80% of wellhead pressure at test gradient. For KS-1A and KS-3, a larger factor of safety is applied.

* KS-4 Plugged and Abondoned 2010

** KS-11 was redrilled in 2009 and new shoe test was performed at 7" casing shoe

ATTACHMENT I – FORMATION TESTING PROGRAM

The implementation of the formation testing program results in several different parameters related to injection of geothermal fluids. The most important parameter is fracture pressure, which essentially controls the rate at which geothermal fluids can be injected into a well. The formation testing program, which results in the identification of the fracture pressure, is identified in Attachment H, Operating Data. This formation testing program will be used to identify the fracture pressure for injection wells to be potentially drilled in the future, as described in the UIC Application Form, Section IX.

KS-15 FORMATION PRESSURE TEST

PT-WH	= 754 psig	Pressure at Wellhead
ρmud	= 8.6 ppg	Mud Weight per gallon
MDKB	= 3901 feet	Measured Depth
TVDKB	= 3855 feet	True Vertical Depth
KB	= 26 feet	Kelly Bushing
.052		Conversion PPG to PSI
.8		Safety Factor, 80%

PT-shoe = PT-WH + 0.052 ρmud TVDKB = 754 + (0.052 × 8.6 × 3855) = 2478 psig

Test Pressure Gradient = 2478/3855 = 0.64 psi/ft

PI-WH = PT-shoe – (80ºF Pres. Gradient) TVDGL = 2478 – 0.434 (3855 – 26) = 816 psig

PMax-WH = 0.8 PI-WH = 0.8 × 816 = 653 psig

Gradient at Max Safe WHP = (653 + 0.434 (3855 – 26))/ 3855 = 0.60 psi/ft

KS-11 FORMATION PRESSURE TEST

PT-WH = 830 psig	Pressure at Wellhead
ρmud = 8.6 ppg	Mud Weight per gallon
MDKB = 4873 feet	Measured Depth
TVDKB = 4766 feet	True Vertical Depth
KB = 26 feet	Kelly Bushing

.052	Conversion PPG to PSI
.8	Safety Factor, 80%

PT-shoe = PT-WH + 0.052 ρmud TVDKB = 830 + (0.052 × 8.6 × 4766) = 2961 psig

Test Pressure Gradient = 2961/4766 = 0.621 psi/ft

PI-WH = PT-shoe – (80ºF Pres. Gradient) TVDGL = 2961 – {0.434 (4766 – 26)} = 904 psig

PMax-WH = 0.8 PI-WH = 0.8 × 904 = 723 psig

Gradient at Max Safe WHP = (723 + 0.434 (4766 – 26))/ 4766 = 0.583 psi/ft

ATTACHMENT J

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ATTACHMENT K – INJECTION PROCEDURES

The following is a description of the injection procedures and process flow for the PGV Project. The process flow, which is essentially a closed system, is described in the flow diagram provided in Figure K-1.

1. GEOTHERMAL FLUIDS

Geothermal fluids (steam and brine) are brought to the surface by production wells where the geothermal fluids are segregated by a separation system. The brine enters a common header and flows to three brine injection pumps. From here, the brine flows to a common header that goes to five injection wells: KS-1A, KS-3, KS-11, KS-13 and KS-15.

The separated steam flows to the power plant through closed piping systems where it is used to run steam turbines as part of the electric generation process. Condensed steam from the ten Ormat Energy Converter (OEC) units is pumped to a collection header. The collection header feeds the condensate injection pumps located in the plant area, where additional corrosion control chemicals are added. From the pumps, the condensate leaves the main power plant area and flows through a mixing element, with noncondensible gases from the power plant.

The combined noncondensible gas and condensate mixture flows through a condensate line to the mixing "T" at the suction of each brine injection pump. This combined mixture (brine/condensate/noncondensible gas) flow, with a temperature commonly in the range of 250º to 300ºF, enters the brine injection pump(s) where pressure is increased to approximately 400 psi. The discharge of the pumps then flows to the reinjection common header before entering the four injection wells, KS-1A, KS-3, KS-11, KS-13 and KS-15.

This process provides for the return of essentially all of the original geothermal fluid (steam and brine) from the production wells to the injection wells and the deep reservoir. The system also includes a number of control features related to well control. Each injection well has a control valve and two manual block valves. These manual valves may be used to stop all flow to an injection well, as needed. Also, in addition to the automatic control systems, each production well has two manual block valves. Attachment O also provides control and shut-off information.

2. SUPPLEMENTAL WATER

In addition to geothermal fluids, the facility uses supplemental water and chemical additives. In comparison to the geothermal fluid flow, which averages approximately 99% of the total flow, the supplemental water and chemical additives are minimal.

Plant Storage Tank. The plant 500,000-gallon storage tank is the source for all process water at the plant. The tank receives water from three sources: the MW-1 water well is the primary source, and county water and MW-3 well water are secondary sources. Approved biocides are occasionally added to the storage tank to control the growth of algae.

Steam Turbine Seal Water. Seal water used for the OEC turbine mechanical seals is pumped from the plant 500,000-gallon storage tank and delivers water through the plant water softener system. Seal water flowing from the softener contains an oxygen scavenger for prevention of equipment/system corrosion. The seal water then flows through the ten OEC turbine units where the seal water fluid may come into contact with the steam process. The discharge of any seal water is then collected in a common header, via the condensate line, and is returned to the reinjection wells.

Water Softener System. The water softener system is used to soften water used in the turbine seal water system. This softener system contains an internal medium called resin beads that conduct the softening. Periodically, these beads are cleansed with a water and sodium-chloride (salt) mixture, and this rinsate flows to the ESRF pond system.

Sulfatreat Heat Exchanger Cooling Water. Plant supply water is used for cooling at the sulfatreat system. This system cools vapors, without contact, pulled through the vacuum process. Cool water is typically returned to the plant storage tank, but on some occasions, may flow to the ESRF pond.

Raw/Quench Water. Raw water is pumped from the plant water storage tank to the condensate reinjection header. This water is used as a quenching (cooling) water for the brine fluids. This pump is utilized during the startup and shutdown phases of the facility. Additives are used for corrosion control and to prevent scale buildup, respectively. The raw water line mixes with ESRF water line and flows to the injection wells.

Emergency Steam Release Facility (ESRF). This facility is used in the event of certain plant upsets and includes a hydrogen sulfide gas abatement process. Fluid from this sytem, which may include geothermal fluids, plant-supply water, and sodium hydroxide, are transferred to an ESRF fiber-reinforced, gunite lined pond. Additionally, this pond collects various supplemental plant water, such as water softener rinsate, sulfatreat vacuum pump seal waters, sulfatreat condensate drain water, periodic sulfatreat cooling water, rainwater, and triple rinse water from the approved additives.

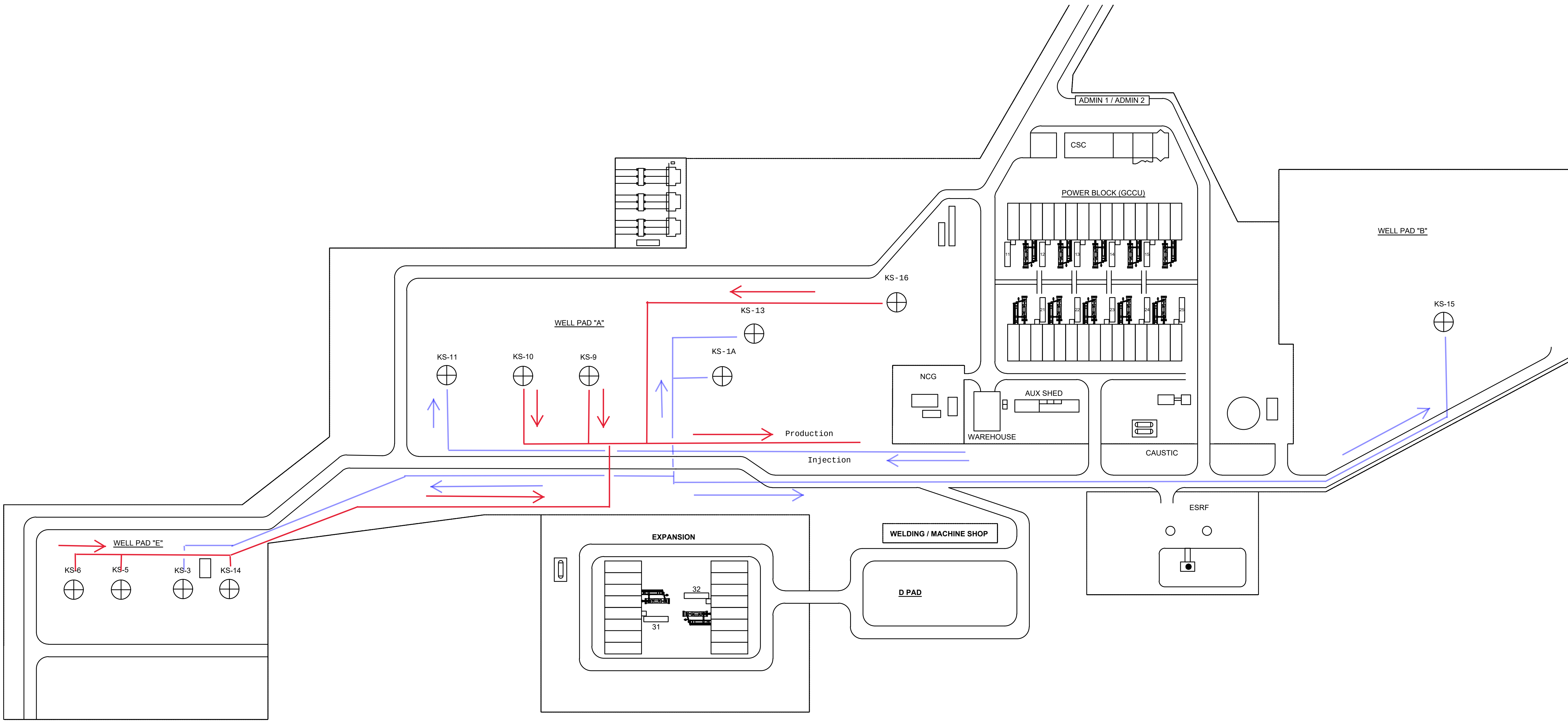
Production Well Bleed System. Periodically, during plant outage, maintenance or repair activities, this well temperature control system is utilized to maintain well casing temperatures. The production well flows steam to the injection wells(s). This is a minimal bleed flow intended to maintain wellhead temperature and to minimize H_2S gas buildup. Supplemental water is added to quench the steam.

Abatement Fluids. Sodium hydroxide is used for abatement of hydrogen sulfide related to drilling and plant repair, preventive maintenance or upsets. Fluids consisting largely of plant supply water and sodium hydroxide periodically are transferred to the ESRF pond or the injection system.

Sulfatreat System Vacuum Pump Seal Water. This system is supplied by plant supply water. This water allows for a seal in the vacuum pump. The seal water drains to the ESRF.

Condensate Drain. Condensate resulting from the operation of the sulfatreat system is drained to the ESRF pond.

Periodic Produced Drilling Fluids. During any drilling activity at the PGV site, all fluids produced from the wells, related to the drilling task, are stored in lined ponds, also referred to as drilling sumps. The fluids, as well as rainwater that accumulates in the drilling sumps, are disposed of via the injection wells. This environmentally sound disposal strategy essentially amounts to returning the produced fluids to the location where they were generated.


ADMIN 1 / ADMIN 2
CSC
POWER BLOCK (GCCU)
WELL PAD "B"
KS-15
KS-16
KS-13
WELL PAD "A"
KS-11
KS-10
KS-9
KS-1A
NCG
AUX SHED
WAREHOUSE
CAUSTIC
Production
Injection
ESRF
WELL PAD "E"
KS-6
KS-5
KS-3
KS-14
EXPANSION
WELDING / MACHINE SHOP
D PAD
31
32

Chemical Injection

Catalyzed Sulfite (Sodium Sulfite, Benzoic Acid)

Catalyzed Sulfite is injected into turbine seal water at discharge line of seal water pumps to control free oxygen in stream in order to prevent corrosion of piping and equipment. After the seal water is used it will go into condensate and then pumped down to reinjection.

GG442 (Quaternary Ammonium Chloride Salt)

GG-442 is injected into the suction of our condensate pumps where it forms a film that makes a constant layer between the metal and fluid to prevent corrosion. Condensate then flows to reinjection, acid dilution system, and sub cooling system for expansion.

Microbiocide CL2150 (Magnesium Nitrate, Cupric Nitrate, Magnesium Chloride)

Microbiocide 2150 is injected into our Fire/Plant water tank. Microbiocide CL2150 is used as an Algaecide to treat our water inside our water tank. The tanks primary use is for fire suppression but also feeds our plant water pumps, seal water pumps, and our raw water pump. Water from these pumps will eventually end up down reinjection through either condensate or direct flow path to one of our reinjection wells

Sulfuric Acid 98% (Sulfuric Acid)

Sulfuric acid is precisely pumped into our brine on the inlet to expansion. Sulfuric acid is used for the control of the Brine PH to inhibit silica scaling throughout our expansion piping. After the brine passes through our expansion it then goes into the mixing area where it mixes with condensate and then down our reinjection wells.

Caustic (Caustic Soda-Diaphragm) (Sodium Hydroxide)

The 50% caustic is transferred, using 50% caustic pump (40-P-44), from 50% caustic tank (40-TK-41) to the (50%) caustic Day tank, and to the diluted (13%) caustic tank (40-TK-42). Plant water to dilute the solution to 13% is injected into the caustic line upstream of the static mixer (40-MX-42) located between the tanks. The mixer ensures a uniform solution of caustic and water. The plant operator, utilizing the local flow meters, FI-4309 in the 50% caustic line and FI-4310 in the water line, carries out the dilution of the concentrated caustic manually. The 15% caustic is used to abate the hydrogen sulfide (H_2S), which forms a sodium sulfide solution when combined with caustic. When a release occurs at the ESRF, one of the 15% caustic pumps (40-P-45 A or B) starts automatically to deliver caustic to ESRF. The sodium sulfide solution collects in a sump at the bottom of the ESRF then is pumped down our reinjection wells.

Barrier fluid (Chevron Tegra barrier fluid) (Synthetic Lubricant)

Barrier fluid is used in our Reinjection pump seals. We use a barrier fluid pump to insure that the barrier fluid is able to over pressure our reinjection fluid and keep a positive seal on the pumps spinning shafts. Barrier fluid would only flow into reinjection if the seals on our reinjection pumps start leaking into reinjection or a seal fails.

APPENDIX H

CHEMICAL ADDITIVES

Note: Some of these products may not currently be used. but are approved for use.

Product Name and Function	Chemical Ingredient
Amersite (R)2 Corrosion Inhibitor	Sodium Bisulfite
Wrico Oxy 11 Corrosion Inhibitor	Sodium Sulfite Ethylanediamine Tetraacetic Acid Sodium Salt
WPD 11-306 (Tm) Corrosion Inhibitor	Dimethyldioctylammnonium Chloride Soya Amine Polyethoxylate Cyclohexylamine
West R-322 Corrosion Inhibitor	Polyamideamine Acetate POE (15) Tallow Amine
Midland 203 Oxygen Scavenger	Sodium Metabisulfite Cobalt Compounds
Millsperse (R) Anti-scalant	802 Poly (Maleic Acid)
Sodium Hydroxide pH Adjustor and H2S Abator	Sodium Hydroxide
Drew 11-480 Corrosion Inhibitor	Soya Amine Poly
ChemTreat Geoguard 452 442 Corrosion Inhibitor	Quaternary Ammonium Chloride Salt
Syncon Barrier Oil	Synthetic Lubricant
Catalyzed Sulfite Oxygen Scavenger	Sodium Sulfite, Benzoic Acid
Drew 11-575 Anti-Scalant	Sodium Chloride Phosphoric Acid Derivative
Biosperse 250 Microbiocide FOR PLANT WATOR USE	Magnesium Nitrate. Cupric Nitrate Magnesium Chloride 2-Methyl-4-Isothiazolin-3-One 5-Chloro-2-Methly-Isothiazolin-3-One
Sulfuric Acid Anti-Scalant PH ADJUSTOR	Sulfuric Acid

SAFETY DATA SHEET

Section 1. Chemical Product and Company Identification

Product Name:	ChemTreat B120
Product Use:	Boiler Water Treatment
Supplier's Name:	ChemTreat, Inc.
Emergency Telephone Number:	(800)424-9300 (Toll Free)
Address (Corporate Headquarters):	5640 Cox Road Glen Allen, VA 23060
Telephone Number for Information:	(800)648-4579
Date of SDS:	May 9, 2016
Revision Date:	May 9, 2016
Revision Number:	16050901AN

Section 2. Hazard(s) Identification

Signal Word: WARNING

GHS Classification(s):
Acute Toxicity Dermal – Category 5
Acute Toxicity Inhalation – Category 5
Acute Toxicity Oral – Category 5

Hazard Statement(s):
H313 May be harmful in contact with skin.
H333 May be harmful if inhaled.
H303 May be harmful if swallowed.

Precautionary Statement(s): Sulfites may cause sensitization to susceptible individuals.

Prevention: None.

Response: None.

Storage: None.

Disposal: None.

System of Classification Used: Classification under 2012 OSHA Hazard Communication Standard (29 CFR 1910.1200).

Hazards Not Otherwise Classified: None.

Section 3. Composition/Hazardous Ingredients

Component	CAS Registry #	Wt.%
Sodium sulfite	7757-83-7	60 - 100

Comments

If chemical identity and/or exact percentage of composition has been withheld, this information is considered to be a trade secret.

Section 4. First Aid Measures

Inhalation:

Remove to fresh air and keep at rest in a position comfortable for breathing. Call a poison center or doctor/physician if you feel unwell.

Eyes:

Rinse cautiously with water for several minutes. Remove contact lenses, if present and easy to do. Continue rinsing. If eye irritation persists, get medical advice/attention.

Skin:

Wash with plenty of soap and water. Call a poison center or doctor/physician if you feel unwell.

Ingestion:

DO NOT INDUCE VOMITING. Rinse mouth. Call a POISON CENTER or doctor/physician if you feel unwell.

Most Important Symptoms:

N/D

Indication of Immediate Medical Attention and Special Treatment Needed, If Necessary:

N/A

Section 5. Fire Fighting Measures

Flammability of the Product:

Not flammable.

Suitable Extinguishing Media:

Use extinguishing media suitable to surrounding fire.

Specific Hazards Arising from the Chemical:

Extreme heating can result in toxic sulfur dioxide fumes.

Protective Equipment: If product is involved in a fire, wear full protective clothing including a positive–pressure, NIOSH approved, self–contained breathing apparatus.

Section 6. Accidental Release Measures

Personal Precautions: Use appropriate Personal Protective Equipment (PPE).

Environmental Precautions: Avoid dispersal of spilled material and runoff and contact with soil, waterways, drains, and sewers.

Methods for Cleaning up: Carefully shovel or sweep up spilled material and place in suitable container.

Other Statements: None.

Section 7. Handling and Storage

Handling: Wear appropriate Personal Protective Equipment (PPE) when handling this product. Do not get in eyes, or on skin and clothing. Wash thoroughly after handling. Do not ingest. Avoid breathing vapors, mist or dust.

Storage: Store away from incompatible materials (see Section 10). Store at ambient temperatures. Keep container securely closed when not in use. Label precautions also apply to empty container. Recondition or dispose of empty containers in accordance with government regulations. For Industrial use only.

Section 8. Exposure Controls/Personal Protection

Exposure Limits

Component	Source	Exposure Limits
Sodium sulfite	N/E	N/E

Engineering Controls: Use only with adequate ventilation. The use of local ventilation is recommended to control emission near the source.

Personal Protection

Eyes:	Wear chemical splash goggles or safety glasses with full-face shield. Maintain eyewash fountain in work area.
Skin:	Maintain quick-drench facilities in work area. Wear butyl rubber or neoprene gloves. Wash them after each use and replace as necessary. If conditions warrant, wear protective clothing such as boots, aprons, and coveralls to prevent skin contact.
Respiratory:	If dust is present during handling, wear a dust mask.

Section 9. Physical and Chemical Properties

Physical State and Appearance:	Granular Solid, White, Opaque
Specific Gravity:	N/A
pH:	8.4 @ 20°C, 1.0%
Freezing Point:	N/A
Flash Point:	N/D
Odor:	Mild
Melting Point:	N/D
Initial Boiling Point and Boiling Range:	N/D
Solubility in Water:	Soluble
Evaporation Rate:	N/D
Vapor Density:	N/D
Molecular Weight:	N/D
Viscosity:	N/A
Flammability (solid, gas):	N/D
Flammable Limits:	N/A
Autoignition Temperature:	N/A
Density:	0.00 LB/GA
Vapor Pressure:	N/D
% VOC:	0
Odor Threshold	N/D
n-octanol Partition Coefficient	N/D
Decomposition Temperature	N/D

Section 10. Stability and Reactivity

Chemical Stability: Stable at normal temperatures and pressures.

Incompatibility with Various Substances: Strong oxidizers, Acids.

Hazardous Decomposition Products: Sodium sulfide residue, Sulfur dioxide gas.

Possibility of Hazardous Reactions: None known.

Reactivity: N/D

Conditions To Avoid: N/D

Section 11. Toxicological Information

Acute Toxicity

Chemical Name	Exposure	Type of Effect	Concentration	Species
Sodium sulfite	Oral	LD50	820 MG/KG	Mouse

Carcinogenicity Category

Component	Source	Code	Brief Description
Sodium sulfite	N/E	N/E	N/E

Likely Routes of Exposure: N/D

Symptoms

Inhalation: N/D

Eye Contact: N/D

Skin Contact: N/D

Ingestion: N/D

Skin Corrosion/Irritation: N/D

Serious Eye Damage/Eye Irritation: N/D

Sensitization: N/D

Germ Cell Mutagenicity: N/D

Reproductive/Developmental Toxicity: N/D

Specific Target Organ Toxicity

Single Exposure: N/D

Repeated Exposure: N/D

Aspiration Hazard: N/D

Comments: None.

Section 12. Ecological Information

Ecotoxicity

Species	Duration	Type of Effect	Test Results
Daphnia magna	48h	LC50	69 mg/l
Fathead Minnow	96h	LC50	>1000 mg/l
Sheepshead Minnow	96h	LC50	>500 mg/l
Mysid Shrimp	48h	LC50	500 mg/l

Persistence and Biodegradability: N/D

Bioaccumulative Potential: N/D

Mobility In Soil: N/D

Other Adverse Effects: N/D

Comments: None.

Section 13. Disposal Considerations

Dispose of in accordance with local, state and federal regulations.

Section 14. Transport Information

Controlling Regulation	UN/NA#:	Proper Shipping Name:	Technical Name:	Hazard Class:	Packing Group:
DOT	N/A	COMPOUND, INDUSTRIAL WATER TREATMENT, DRY	N/A	N/A	N/A
IMDG	N/A	COMPOUND, INDUSTRIAL WATER TREATMENT, DRY	N/A	N/A	N/A
ICAO	N/A	COMPOUND, INDUSTRIAL WATER TREATMENT, DRY	N/A	N/A	N/A
TDG	N/A	COMPOUND, INDUSTRIAL WATER TREATMENT, DRY	N/A	N/A	N/A

Note: N/A

Section 15. Regulatory Information

Inventory Status

United States (TSCA): All ingredients listed.
Canada (DSL/NDSL): All ingredients listed.

Federal Regulations

SARA Title III Rules

Sections 311/312 Hazard Classes

Fire Hazard: No
Reactive Hazard: No
Release of Pressure: No
Acute Health Hazard: Yes
Chronic Health Hazard: No

Other Sections

Component	Section 313 Toxic Chemical	Section 302 EHS TPQ	CERCLA RQ
Sodium sulfite	N/A	N/A	N/A

Comments: None.

State Regulations

California Proposition 65: None known.

Special Regulations

Component	States
Sodium sulfite	None.

International Regulations

Canada

WHMIS Classification: N/A

Controlled Product Regulations (CPR): N/A

Compliance Information

NSF: N/A

Food Regulations: FDA: All ingredients in this product are authorized in 21 CFR 173.310 for use as "Boiler Water Additives" where the steam may contact food.

KOSHER: This product is certified by the Orthodox Union as kosher pareve.
Only when prepared by the following ChemTreat facilities:
Ashland, VA; Eldridge, IA; Nederland, TX; Vernon, CA.

FIFRA: N/A

Other: None

Comments: None.

ChemTreat

SDS

Section 16. Other Information

HMIS Hazard Rating

Health:	2
Flammability:	0
Physical Hazard:	1
PPE:	X

Notes: The PPE rating depends on circumstances of use. See Section 8 for recommended PPE.
The Hazardous Material Information System (HMIS) is a voluntary, subjective alpha-numeric symbolic system for recommending hazard risk and personal protection equipment information. It is a subjective rating system based on the evaluator's understanding of the chemical associated risks. The end-user must determine if the code is appropriate for their use.

Abbreviations

Abbreviation	Definition
<	Less Than
>	Greater Than
ACGIH	American Conference of Governmental Industrial Hygienists
EHS	Environmental Health and Safety Dept
N/A	Not Applicable
N/D	Not Determined
N/E	Not Established
OSHA	Occupational Health and Safety Dept
PEL	Personal Exposure Limit
STEL	Short Term Exposure Limit
TLV	Threshold Limit Value
TWA	Time Weight Average
UNK	Unknown

Prepared by: Product Compliance Department; ProductCompliance@chemtreat.com

Revision Date: May 9, 2016

Disclaimer

Although the information and recommendations set forth herein (hereinafter "information") are presented in good faith and believed to be correct as of the date hereof, ChemTreat, Inc. makes no representations as to the completeness or accuracy thereof. Information is supplied upon the condition that the persons receiving same will make their own determination as to its suitability for their purposes prior to use. In no event will ChemTreat, Inc. be responsible for damages of any nature whatsoever resulting from the use or reliance upon information. No representation or warranties, either expressed or implied, of merchantability, fitness for a particular purpose, or of any other nature are made hereunder with respect to information or the product to which information refers.

Material Safety Data Sheet

Chevron

SECTION 1 PRODUCT AND COMPANY IDENTIFICATION

Tegra Synthetic Barrier Fluid

Product Use: Industrial Oil
Product Number(s): CPS210448
Company Identification
Chevron Products Company
a division of Chevron U.S.A. Inc.
6001 Bollinger Canyon Rd.
San Ramon, CA 94583
United States of America
www.chevronlubricants.com

Transportation Emergency Response
CHEMTREC: (800) 424-9300 or (703) 527-3887
Health Emergency
Chevron Emergency Information Center: Located in the USA. International collect calls accepted. (800) 231-0623 or (510) 231-0623
Product Information
email : lubemsds@chevron.com
Product Information: (800) LUBE TEK

SECTION 2 COMPOSITION/ INFORMATION ON INGREDIENTS

This material contains no ingredients requiring disclosure under the regulatory criteria for this jurisdiction.

SECTION 3 HAZARDS IDENTIFICATION

IMMEDIATE HEALTH EFFECTS
Eye: Not expected to cause prolonged or significant eye irritation.
Skin: Contact with the skin is not expected to cause prolonged or significant irritation. Contact with the skin is not expected to cause an allergic skin response. Not expected to be harmful to internal organs if absorbed through the skin.
Ingestion: Not expected to be harmful if swallowed.
Inhalation: Not expected to be harmful if inhaled. Contains a synthetic hydrocarbon oil. May cause respiratory irritation or other pulmonary effects following prolonged or repeated inhalation of oil mist at airborne levels above the recommended mineral oil mist exposure limit. Symptoms of respiratory irritation may include coughing and difficulty breathing.

SECTION 4 FIRST AID MEASURES

Eye: No specific first aid measures are required. As a precaution, remove contact lenses, if worn, and flush eyes with water.
Skin: No specific first aid measures are required. As a precaution, remove clothing and shoes if contaminated. To remove the material from skin, use soap and water. Discard contaminated clothing and shoes or thoroughly clean before reuse.
Ingestion: No specific first aid measures are required. Do not induce vomiting. As a precaution, get medical advice.
Inhalation: No specific first aid measures are required. If exposed to excessive levels of material in the air, move the exposed person to fresh air. Get medical attention if coughing or respiratory discomfort occurs.

SECTION 5 FIRE FIGHTING MEASURES

FIRE CLASSIFICATION:
OSHA Classification (29 CFR 1910.1200): Not classified by OSHA as flammable or combustible.

NFPA RATINGS: Health: 0 Flammability: 1 Reactivity: 0

FLAMMABLE PROPERTIES:
Flashpoint: (Cleveland Open Cup) 210 °C (410 °F) Minimum
Autoignition: No data available
Flammability (Explosive) Limits (% by volume in air): Lower: Not Applicable Upper: Not Applicable

EXTINGUISHING MEDIA: Use water fog, foam, dry chemical or carbon dioxide (CO_2) to extinguish flames.

PROTECTION OF FIRE FIGHTERS:
Fire Fighting Instructions: This material will burn although it is not easily ignited. For fires involving this material, do not enter any enclosed or confined fire space without proper protective equipment, including self-contained breathing apparatus.
Combustion Products: Highly dependent on combustion conditions. A complex mixture of airborne solids, liquids, and gases including carbon monoxide, carbon dioxide, and unidentified organic compounds will be evolved when this material undergoes combustion.

SECTION 6 ACCIDENTAL RELEASE MEASURES

Protective Measures: Eliminate all sources of ignition in vicinity of spilled material.
Spill Management: Stop the source of the release if you can do it without risk. Contain release to prevent further contamination of soil, surface water or groundwater. Clean up spill as soon as possible, observing precautions in Exposure Controls/Personal Protection. Use appropriate techniques such as applying non-combustible absorbent materials or pumping. Where feasible and appropriate, remove contaminated soil. Place contaminated materials in disposable containers and dispose of in a manner consistent with applicable regulations.
Reporting: Report spills to local authorities and/or the U.S. Coast Guard's National Response Center at (800) 424-8802 as appropriate or required.

SECTION 7 HANDLING AND STORAGE

General Handling Information: Avoid contaminating soil or releasing this material into sewage and drainage systems and bodies of water.
Static Hazard: Electrostatic charge may accumulate and create a hazardous condition when handling this material. To minimize this hazard, bonding and grounding may be necessary but may not, by themselves, be sufficient. Review all operations which have the potential of generating and accumulating an electrostatic

charge and/or a flammable atmosphere (including tank and container filling, splash filling, tank cleaning, sampling, gauging, switch loading, filtering, mixing, agitation, and vacuum truck operations) and use appropriate mitigating procedures. For more information, refer to OSHA Standard 29 CFR 1910.106, 'Flammable and Combustible Liquids', National Fire Protection Association (NFPA 77, 'Recommended Practice on Static Electricity', and/or the American Petroleum Institute (API) Recommended Practice 2003, 'Protection Against Ignitions Arising Out of Static, Lightning, and Stray Currents'.
Container Warnings: Container is not designed to contain pressure. Do not use pressure to empty container or it may rupture with explosive force. Empty containers retain product residue (solid, liquid, and/or vapor) and can be dangerous. Do not pressurize, cut, weld, braze, solder, drill, grind, or expose such containers to heat, flame, sparks, static electricity, or other sources of ignition. They may explode and cause injury or death. Empty containers should be completely drained, properly closed, and promptly returned to a drum reconditioner or disposed of properly.

SECTION 8 EXPOSURE CONTROLS/PERSONAL PROTECTION

GENERAL CONSIDERATIONS:
Consider the potential hazards of this material (see Section 3), applicable exposure limits, job activities, and other substances in the work place when designing engineering controls and selecting personal protective equipment. If engineering controls or work practices are not adequate to prevent exposure to harmful levels of this material, the personal protective equipment listed below is recommended. The user should read and understand all instructions and limitations supplied with the equipment since protection is usually provided for a limited time or under certain circumstances.

ENGINEERING CONTROLS:
Use in a well-ventilated area.

PERSONAL PROTECTIVE EQUIPMENT
Eye/Face Protection: No special eye protection is normally required. Where splashing is possible, wear safety glasses with side shields as a good safety practice.
Skin Protection: No special protective clothing is normally required. Where splashing is possible, select protective clothing depending on operations conducted, physical requirements and other substances in the workplace. Suggested materials for protective gloves include: Nitrile Rubber, Silver Shield, Viton.
Respiratory Protection: No respiratory protection is normally required.
If user operations generate an oil mist, determine if airborne concentrations are below the occupational exposure limit for mineral oil mist. If not, wear an approved respirator that provides adequate protection from the measured concentrations of this material. For air-purifying respirators use a particulate cartridge. Use a positive pressure air-supplying respirator in circumstances where air-purifying respirators may not provide adequate protection.
Consult local authorities for appropriate values.

SECTION 9 PHYSICAL AND CHEMICAL PROPERTIES

Attention: the data below are typical values and do not constitute a specification.

Color: Colorless
Physical State: Liquid
Odor: Hydrocarbon odor
pH: Not Applicable
Vapor Pressure: <0.01 mmHg @ 37.8 °C (100 °F)
Vapor Density (Air = 1): >1
Boiling Point: 235°C (455°F)
Solubility: Soluble in hydrocarbons; insoluble in water
Freezing Point: Not Applicable
Density: 0.82 kg/l @ 15.6°C (60.1°F) (Typical)

Viscosity: 19.4 mm2/s @ 40°C (104°F) (Typical)
Evaporation Rate: No data available

SECTION 10 STABILITY AND REACTIVITY

Chemical Stability: This material is considered stable under normal ambient and anticipated storage and handling conditions of temperature and pressure.
Incompatibility With Other Materials: May react with strong acids or strong oxidizing agents, such as chlorates, nitrates, peroxides, etc.
Hazardous Decomposition Products: None known (None expected)
Hazardous Polymerization: Hazardous polymerization will not occur.

SECTION 11 TOXICOLOGICAL INFORMATION

IMMEDIATE HEALTH EFFECTS
Eye Irritation: The eye irritation hazard is based on evaluation of data for similar materials or product components.
Skin Irritation: The skin irritation hazard is based on evaluation of data for similar materials or product components.
Skin Sensitization: The skin sensitization hazard is based on evaluation of data for similar materials or product components.
Acute Dermal Toxicity: The acute dermal toxicity hazard is based on evaluation of data for similar materials or product components.

Acute Oral Toxicity: The acute oral toxicity hazard is based on evaluation of data for similar materials or product components.

Acute Inhalation Toxicity: The acute inhalation toxicity hazard is based on evaluation of data for similar materials or product components.

SECTION 12 ECOLOGICAL INFORMATION

ECOTOXICITY
This material is not expected to be harmful to aquatic organisms. The ecotoxicity hazard is based on an evaluation of data for the components or a similar material.

ENVIRONMENTAL FATE
Ready Biodegradability: This material is not expected to be readily biodegradable. The biodegradability of this material is based on an evaluation of data for the components or a similar material.

SECTION 13 DISPOSAL CONSIDERATIONS

Use material for its intended purpose or recycle if possible. Oil collection services are available for used oil recycling or disposal. Place contaminated materials in containers and dispose of in a manner consistent with applicable regulations. Contact your sales representative or local environmental or health authorities for approved disposal or recycling methods.

SECTION 14 TRANSPORT INFORMATION

The description shown may not apply to all shipping situations. Consult 49CFR, or appropriate Dangerous Goods Regulations, for additional description requirements (e.g., technical name) and mode-specific or quantity-specific shipping requirements.

DOT Shipping Description: PETROLEUM OIL, N.E.C.; NOT REGULATED AS A HAZARDOUS MATERIAL FOR TRANSPORTATION UNDER 49 CFR
Additional Information:NOT HAZARDOUS BY U.S. DOT. ADR/RID HAZARD CLASS NOT APPLICABLE.

IMO/IMDG Shipping Description: NOT REGULATED AS DANGEROUS GOODS FOR TRANSPORT UNDER THE IMDG CODE

ICAO/IATA Shipping Description: NOT REGULATED AS DANGEROUS GOODS FOR TRANSPORTATION UNDER ICAO

SECTION 15 REGULATORY INFORMATION

EPCRA 311/312 CATEGORIES:

1. Immediate (Acute) Health Effects: NO
2. Delayed (Chronic) Health Effects: NO
3. Fire Hazard: NO
4. Sudden Release of Pressure Hazard: NO
5. Reactivity Hazard: NO

REGULATORY LISTS SEARCHED:

01-1=IARC Group 1	03=EPCRA 313
01-2A=IARC Group 2A	04=CA Proposition 65
01-2B=IARC Group 2B	05=MA RTK
02=NTP Carcinogen	06=NJ RTK
	07=PA RTK

No components of this material were found on the regulatory lists above.

CHEMICAL INVENTORIES:
All components comply with the following chemical inventory requirements: AICS (Australia), DSL (Canada), EINECS (European Union), ENCS (Japan), IECSC (China), KECI (Korea), PICCS (Philippines), TSCA (United States).

NEW JERSEY RTK CLASSIFICATION:
Under the New Jersey Right-to-Know Act L. 1983 Chapter 315 N.J.S.A. 34:5A-1 et. seq., the product is to be identified as follows: Synthetic Base Oil (Lubricating oil)

WHMIS CLASSIFICATION:
This product is not considered a controlled product according to the criteria of the Canadian Controlled Products Regulations.

SECTION 16 OTHER INFORMATION

NFPA RATINGS: Health: 0 Flammability: 1 Reactivity: 0

HMIS RATINGS: Health: 1 Flammability: 1 Reactivity: 0
(0-Least, 1-Slight, 2-Moderate, 3-High, 4-Extreme, PPE:- Personal Protection Equipment Index recommendation, *- Chronic Effect Indicator). These values are obtained using the guidelines or published evaluations prepared by the National Fire Protection Association (NFPA) or the National Paint and Coating Association (for HMIS ratings).

LABEL RECOMMENDATION:
Label Category : INDUSTRIAL OIL 1 - IND1

REVISION STATEMENT: This revision updates the following sections of this Material Safety Data Sheet: 9,16
Revision Date: AUGUST 01, 2012

ABBREVIATIONS THAT MAY HAVE BEEN USED IN THIS DOCUMENT:

TLV - Threshold Limit Value	TWA - Time Weighted Average
STEL - Short-term Exposure Limit	PEL - Permissible Exposure Limit
	CAS - Chemical Abstract Service Number
ACGIH - American Conference of Governmental Industrial Hygienists	IMO/IMDG - International Maritime Dangerous Goods Code
API - American Petroleum Institute	MSDS - Material Safety Data Sheet
CVX - Chevron	NFPA - National Fire Protection Association (USA)
DOT - Department of Transportation (USA)	NTP - National Toxicology Program (USA)
IARC - International Agency for Research on Cancer	OSHA - Occupational Safety and Health Administration

Prepared according to the OSHA Hazard Communication Standard (29 CFR 1910.1200) and the ANSI MSDS Standard (Z400.1) by the Chevron Energy Technology Company, 100 Chevron Way, Richmond, California 94802.

The above information is based on the data of which we are aware and is believed to be correct as of the date hereof. Since this information may be applied under conditions beyond our control and with which we may be unfamiliar and since data made available subsequent to the date hereof may suggest modifications of the information, we do not assume any responsibility for the results of its use. This information is furnished upon condition that the person receiving it shall make his own determination of the suitability of the material for his particular purpose.

SAFETY DATA SHEET

Section 1. Chemical Product and Company Identification

Product Name:	Chemical Treatment CL2150
Product Use:	Cooling Water Microbiocide and Paper Slimicide
Supplier's Name:	ChemTreat, Inc.
Emergency Telephone Number:	(800)424–9300 (Toll Free)
Address (Corporate Headquarters):	5640 Cox Road Glen Allen, VA 23060
Telephone Number for Information:	(800)648–4579
Date of SDS:	May 9, 2016
Revision Date:	May 9, 2016
Revision Number:	16050901AN

Section 2. Hazard(s) Identification

Signal Word: **DANGER**

GHS Classification(s):

Skin corrosion/irritation – Category 1b
Eye damage/irritation – Category 1
Acute Toxicity Dermal – Category 4
Acute Toxicity Inhalation – Category 4
Acute Toxicity Oral – Category 4
Hazardous to the aquatic environment Acute – Category 3

Hazard Statement(s):

H314 Causes severe skin burns and eye damage.
H318 Causes serious eye damage.
H312 Harmful in contact with skin.
H332 Harmful if inhaled.
H302 Harmful if swallowed.
H402 Harmful to aquatic life.

Precautionary Statement(s):

Prevention:

P260 Do not breathe dust/fume/gas/mist/vapors/spray.
P264 Wash thoroughly after handling.
P270 Do not eat, drink, or smoke when using this product.
P271 Use only outdoors or in a well–ventilated area.
P280 Wear protective gloves/protective clothing/eye protection/face protection.
P273 Avoid release into the environment.

Response: P301 + P312 IF SWALLOWED: Call a POISON CENTER or doctor/physician if you feel unwell
P301 + 330 + 331 IF SWALLOWED: Rinse mouth. Do NOT induce vomiting.
P303 + P361 + P353 IF ON SKIN (or hair): Remove/take off immediately all contaminated clothing. Rinse skin with water/shower
P304 + P340 IF INHALED: Remove person to fresh air and keep comfortable for breathing
P305 + P351 + P388 IF IN EYES: Rinse cautiously with water for several minutes. Remove contact lenses, if present and easy to do. Continue rinsing.
P310 Immediately call a POISON CENTER/doctor.
P363 Wash contaminated clothing before reuse.

Storage: P405 Store locked up.

Disposal: P501 Dispose of contents and container in accordance with applicable local, regional, national, and/or international regulations.

System of Classification Used: Classification under 2012 OSHA Hazard Communication Standard (29 CFR 1910.1200).

Hazards Not Otherwise Classified: None.

Section 3. Composition/Hazardous Ingredients

Component	CAS Registry #	Wt.%
5-chloro-2-methyl-4-isothiazolin-3-one	26172-55-4	1.11
2-methyl-4-isothiazolin-3-one	2682-20-4	0.39

Comments If chemical identity and/or exact percentage of composition has been withheld, this information is considered to be a trade secret.

Section 4. First Aid Measures

Inhalation: Remove victim to fresh air and keep at rest in a position comfortable for breathing. Immediately call a poison center or doctor/physician.

Eyes: Rinse cautiously with water for several minutes. Remove contact lenses, if present and easy to do. Continue rinsing. Immediately call a poison center or doctor/physician.

Skin:	Immediately remove/take off all contaminated clothing. Rinse skin with water/shower. Wash contaminated clothing before re-use. Immediately call a poison center or doctor/physician.
Ingestion:	DO NOT INDUCE VOMITING. Rinse mouth. Call a POISON CENTER or doctor/physician.
Most Important Symptoms:	N/D
Indication of Immediate Medical Attention and Special Treatment Needed, If Necessary:	Probable mucosal damage may contraindicate the use of gastric lavage. Have the product container, label or MSDS with you when calling a poison control center or doctor, or when going for treatment.

Section 5. Fire Fighting Measures

Flammability of the Product:	Not flammable.
Suitable Extinguishing Media:	Use extinguishing media suitable to surrounding fire.
Specific Hazards Arising from the Chemical:	Use water spray to keep containers cool.
Protective Equipment:	If product is involved in a fire, wear full protective clothing including a positive-pressure, NIOSH approved, self-contained breathing apparatus.

Section 6. Accidental Release Measures

Personal Precautions:	Use appropriate Personal Protective Equipment (PPE).
Environmental Precautions:	This pesticide is toxic to fish and aquatic organisms. Do not discharge effluent containing this product into lakes, ponds, streams, estuaries, oceans or public waters unless in accordance with the requirements of a National Pollutant Discharge Elimination System (NPDES) permit, and the permitting authority has been notified in writing prior to discharge. Do not discharge effluent containing this product to sewer systems without previously notifying the local sewage treatment plant authority. For guidance contact your State Water Board or Regional Office of the EPA.
Methods for Cleaning up:	Contain and recover liquid when possible. Flush spill area with water spray.

Other Statements:	If RQ (Reportable Quantity) is exceeded, report to National Spill Response Office at 1-800-424-8802.

Section 7. Handling and Storage

Handling:

Wear appropriate Personal Protective Equipment (PPE) when handling this product. Do not get in eyes, or on skin and clothing. Wash thoroughly after handling. Do not ingest. Avoid breathing vapors, mist or dust.

Storage:

Store away from incompatible materials (see Section 10). Store at ambient temperatures. Keep container securely closed when not in use. Label precautions also apply to empty container. Recondition or dispose of empty containers in accordance with government regulations. For Industrial use only.
Store in corrosive resistant container with a resistant inliner.
Store above Freeze Point.

Section 8. Exposure Controls/Personal Protection

Exposure Limits

Component	Source	Exposure Limits
5-chloro-2-methyl-4-isothiazolin-3-one	N/E	N/E
2-methyl-4-isothiazolin-3-one	N/E	N/E

Engineering Controls:

Use only with adequate ventilation. The use of local ventilation is recommended to control emission near the source.

Personal Protection

Eyes:

Wear chemical splash goggles or safety glasses with full-face shield. Maintain eyewash fountain in work area.

Skin:

Maintain quick-drench facilities in work area.
Wear butyl rubber or neoprene gloves. Wash them after each use and replace as necessary. If conditions warrant, wear protective clothing such as boots, aprons, and coveralls to prevent skin contact.

Respiratory:

If misting occurs, use NIOSH approved organic vapor/acid gas dual cartridge respirator with a dust/mist prefilter in accordance with 29 CFR 1910.134.

Section 9. Physical and Chemical Properties

Physical State and Appearance:	Liquid, Green, Clear
Specific Gravity:	1.025 @ 20°C
pH:	3.6 @ 20°C, 100.0%
Freezing Point:	45°F
Flash Point:	N/D
Odor:	Mild
Melting Point:	N/A
Initial Boiling Point and Boiling Range:	N/D
Solubility in Water:	Complete
Evaporation Rate:	<1
Vapor Density:	N/D
Molecular Weight:	N/D
Viscosity:	N/D
Flammability (solid, gas):	N/D
Flammable Limits:	N/A
Autoignition Temperature:	N/A
Density:	8.55 LB/GA
Vapor Pressure:	N/D
% VOC:	<0.1
Odor Threshold	N/D
n-octanol Partition Coefficient	N/D
Decomposition Temperature	N/D

Section 10. Stability and Reactivity

Chemical Stability:	Stable at normal temperatures and pressures.
Incompatibility with Various Substances:	Strong oxidizers, Strong bases.
Hazardous Decomposition Products:	Oxides of nitrogen, Oxides of sulfur, Oxides of carbon, Halogenated compounds.
Possibility of Hazardous Reactions:	None known.
Reactivity:	N/D
Conditions To Avoid:	N/D

Section 11. Toxicological Information

Acute Toxicity

Chemical Name	Exposure	Type of Effect	Concentration	Species
Chemical Treatment CL2150	Oral	LD50	3810 MG/KG	Rat
	Dermal	LD50	>5000 MG/KG	Rabbit
	Inhalation	LD50	13.7 MG/L	Rat

Carcinogenicity Category

Component	Source	Code	Brief Description
5-chloro-2-methyl-4-isothiazolin-3-one	N/E	N/E	N/E
2-methyl-4-isothiazolin-3-one	N/E	N/E	N/E

Likely Routes of Exposure: N/D

Symptoms

Inhalation: N/D

Eye Contact: N/D

Skin Contact: N/D

Ingestion: N/D

Skin Corrosion/Irritation: N/D

Serious Eye Damage/Eye Irritation: N/D

Sensitization: N/D

Germ Cell Mutagenicity: N/D

Reproductive/Developmental Toxicity: N/D

Specific Target Organ Toxicity

Single Exposure: N/D

Repeated Exposure: N/D

Aspiration Hazard: N/D

Comments: None.

Section 12. Ecological Information

Ecotoxicity

Species	Duration	Type of Effect	Test Results
Daphnia magna	48h	LC50	10.7 mg/l
Bluegill Sunfish	96h	LC50	18.6 mg/l
Ceriodaphnia dubia	48h	EC50	10.7 mg/l
Rainbow Trout	96h	LC50	12.6 mg/l
Sheepshead Minnow	96h	LC50	70.7 mg/l
Mysid Shrimp	48h	LC50	46.1 mg/l
Daphnia pulex	48h	LC50	17 mg/l
Fathead Minnow	48h	LC50	8.7 mg/l

Persistence and Biodegradability: N/D

Bioaccumulative Potential: N/D

Mobility In Soil: N/D

Other Adverse Effects: N/D

Comments: None.

Section 13. Disposal Considerations

PESTICIDE DISPOSAL: Pesticide wastes are toxic. Improper disposal of excess pesticide, spray mixture, or rinsate is a violation of Federal Law. If these wastes cannot be disposed of by use according to label instructions, contact your State Pesticide or Environmental Control Agency, or the Hazardous Waste representative at the nearest EPA Regional Office for guidance.
CONTAINER DISPOSAL: Non-refillable container. Do not reuse or refill this container. Triple rinse or pressure rinse container (or equivalent) promptly after emptying. Then offer for recycling or reconditioning, or puncture and dispose of in a sanitary landfill, or by procedures approved by state and local authorities.

Section 14. Transport Information

Controlling Regulation	UN/NA#:	Proper Shipping Name:	Technical Name:	Hazard Class:	Packing Group:
DOT	UN1760	CORROSIVE LIQUIDS, N.O.S.	(5-CHLORO-2-METHYL-4-ISOTHIAZOLIN-3-ONE AND 2-METHYL-4-ISOTHIAZOLIN-3-ONE)	8	PGII
IMDG	UN1760	CORROSIVE LIQUIDS, N.O.S.	(5-CHLORO-2-METHYL-4-ISOTHIAZOLIN-3-ONE AND 2-METHYL-4-ISOTHIAZOLIN-3-ONE)	8	PGII
TDG	UN1760	CORROSIVE LIQUIDS, N.O.S.	(5-CHLORO-2-METHYL-4-ISOTHIAZOLIN-3-ONE AND 2-METHYL-4-ISOTHIAZOLIN-3-ONE)	8	PGII
ICAO	UN1760	CORROSIVE LIQUIDS, N.O.S.	(5-CHLORO-2-METHYL-4-ISOTHIAZOLIN-3-ONE AND 2-METHYL-4-ISOTHIAZOLIN-3-ONE)	8	PGII
SCT	UN1760	CORROSIVE LIQUIDS, N.O.S.	(5-CHLORO-2-METHYL-4-ISOTHIAZOLIN-3-ONE AND 2-METHYL-4-ISOTHIAZOLIN-3-ONE)	8	PGII

Note: N/A

Section 15. Regulatory Information

Inventory Status

United States (TSCA): All ingredients listed.
Canada (DSL/NDSL): All ingredients listed.

ChemTreat SDS

Federal Regulations

SARA Title III Rules

Sections 311/312 Hazard Classes

Fire Hazard:	No
Reactive Hazard:	No
Release of Pressure:	No
Acute Health Hazard:	Yes
Chronic Health Hazard:	No

Other Sections

Component	Section 313 Toxic Chemical	Section 302 EHS TPQ	CERCLA RQ
5-chloro-2-methyl-4-isothiazolin-3-one	N/A	N/A	N/A
2-methyl-4-isothiazolin-3-one	N/A	N/A	N/A

Comments: None.

State Regulations

California Proposition 65: None known.

Special Regulations

Component	States
5-chloro-2-methyl-4-isothiazolin-3-one	None.
2-methyl-4-isothiazolin-3-one	None.

International Regulations

Canada

WHMIS Classification: N/A

Controlled Product Regulations (CPR): N/A

Compliance Information

NSF:	N/A
Food Regulations:	FDA: All ingredients in this product are authorized in 21 CFR 176.170 and 21 CFR 176.180.
KOSHER:	This product is certified by the Orthodox Union as Kosher for Passover and year–round use. Only when prepared by the following ChemTreat facilities: Ashland, VA; Eldridge, IA; Nederland, TX; Vernon, CA.
FIFRA:	Registered pesticide under 40 CFR 152.10, Federal Insecticide, Fungicide and Rodenticide Act (FIFRA), EPA Registration Number: 15300–24.
Other:	PMRA biocide registration NO. 26537.

Comments: None.

Section 16. Other Information

HMIS Hazard Rating

Health:	3
Flammability:	0
Physical Hazard:	0
PPE:	X

Notes:

The PPE rating depends on circumstances of use. See Section 8 for recommended PPE.
The Hazardous Material Information System (HMIS) is a voluntary, subjective alpha–numeric symbolic system for recommending hazard risk and personal protection equipment information. It is a subjective rating system based on the evaluator's understanding of the chemical associated risks. The end–user must determine if the code is appropriate for their use.

Abbreviations

Abbreviation	Definition
<	Less Than
>	Greater Than
ACGIH	American Conference of Governmental Industrial Hygienists
EHS	Environmental Health and Safety Dept
N/A	Not Applicable
N/D	Not Determined
N/E	Not Established

Abbreviation	Definition
OSHA	Occupational Health and Safety Dept
PEL	Personal Exposure Limit
STEL	Short Term Exposure Limit
TLV	Threshold Limit Value
TWA	Time Weight Average
UNK	Unknown

Prepared by: Product Compliance Department; ProductCompliance@chemtreat.com

Revision Date: May 9, 2016

Disclaimer

SAFETY DATA SHEET

Section 1. Chemical Product and Company Identification

Product Name:	ChemTreat GG442
Product Use:	Geothermal Corrosion Inhibitor
Supplier's Name:	ChemTreat, Inc.
Emergency Telephone Number:	(800)424-9300 (Toll Free)
Address (Corporate Headquarters):	5640 Cox Road Glen Allen, VA 23060
Telephone Number for Information:	(800)648-4579
Date of MSDS:	September 14, 2015
Revision Date:	September 14, 2015
Revision Number:	15091401AN

Section 2. Hazard(s) Identification

Signal Word:	**WARNING**
GHS Classification(s):	Acute Toxicity Dermal – Category 5 Acute Toxicity Inhalation – Category 5 Acute Toxicity Oral – Category 5 Hazardous to the aquatic environment Acute – Category 2
Hazard Statement(s):	May be harmful in contact with skin. May be harmful if inhaled. May be harmful if swallowed. Toxic to aquatic life.
Precautionary Statement(s):	Keep away from heat, hot surfaces, sparks, open flames and other ignition sources. No smoking. Avoid release into the environment.
System of Classification Used:	Classification under 2012 OSHA Hazard Communication Standard (29 CFR 1910.1200).
Hazards Not Otherwise Classified:	None.

Section 3. Composition/Hazardous Ingredients

Component	CAS Registry #	Wt.%
2−Propanol	67−63−0	1 − 5
Acetic acid	64−19−7	3 − 7

Comments If chemical identity and/or exact percentage of composition has been withheld, this information is considered to be a trade secret.

Section 4. First Aid Measures

Inhalation: Remove to fresh air and keep at rest in a position comfortable for breathing. Call a poison center or doctor/physician if you feel unwell.

Eyes: Rinse cautiously with water for several minutes. Remove contact lenses, if present and easy to do. Continue rinsing. If eye irritation persists, get medical advice/attention.

Skin: Wash with plenty of soap and water. Call a poison center or doctor/physician if you feel unwell.

Ingestion: DO NOT INDUCE VOMITING. Rinse mouth. Call a POISON CENTER or doctor/physician if you feel unwell.

Notes to Physician: N/A

Additional First Aid Remarks: N/A

Section 5. Fire Fighting Measures

Flammability of the Product: Negative results obtained in sustained combustion test.

Suitable Extinguishing Media: Use extinguishing media suitable to surrounding fire.

Specific Hazards Arising from the Chemical: Use water spray to keep containers cool.

Protective Equipment: If product is involved in a fire, wear full protective clothing including a positive−pressure, NIOSH approved, self−contained breathing apparatus.

Section 6. Accidental Release Measures

Personal Precautions: Use appropriate Personal Protective Equipment (PPE).

Environmental Precautions: Avoid dispersal of spilled material and runoff and contact with soil, waterways, drains, and sewers.

Methods for Cleaning up: Contain and recover liquid when possible. Flush spill area with water spray.

Other Statements: If RQ (Reportable Quantity) is exceeded, report to National Spill Response Office at 1−800−424−8802.

Section 7. Handling and Storage

Handling: Wear appropriate Personal Protective Equipment (PPE) when handling this product. Do not get in eyes, or on skin and clothing. Wash thoroughly after handling. Do not ingest. Avoid breathing vapors, mist or dust.

Storage: Store away from incompatible materials (see Section 10). Store at ambient temperatures. Keep container securely closed when not in use. Label precautions also apply to empty container. Recondition or dispose of empty containers in accordance with government regulations.
For Industrial use only.
Protect from heat and sources of ignition.
Store above Freeze Point.

Section 8. Exposure Controls/Personal Protection

Exposure Limits

Component	Source	Exposure Limits
2−Propanol	ACGIH TLV	984 mg/m³ STEL
	OSHA PEL	980 mg/m³ TWA
Acetic acid	ACGIH TLV	37 mg/m³ STEL
	OSHA PEL	25 mg/m³ TWA

Engineering Controls: Use only with adequate ventilation. The use of local ventilation is recommended to control emission near the source.

Personal Protection

Eyes: Wear chemical splash goggles or safety glasses with full-face shield.

Skin: Wear butyl rubber or neoprene gloves. Wash them after each use and replace as necessary. If conditions warrant, wear protective clothing such as boots, aprons, and coveralls to prevent skin contact.

Respiratory: If misting occurs, use NIOSH approved organic vapor/acid gas dual cartridge respirator with a dust/mist prefilter in accordance with 29 CFR 1910.134.

Section 9. Physical and Chemical Properties

Physical State and Appearance:	Liquid, Amber, Clear
Specific Gravity:	0.998 @ 20°C
pH:	4.5 @ 20°C, 100.0%
Freezing Point:	32°F
Flash Point:	N/D
Odor:	Moderate
Melting Point:	N/A
Initial Boiling Point and Boiling Range:	N/D
Solubility in Water:	Complete
Evaporation Rate:	N/D
Vapor Density:	N/D
Molecular Weight:	N/D
Viscosity:	<100 CPS @ 20°C
Flammability (solid, gas):	N/D
Flammable Limits:	N/A
Autoignition Temperature:	N/A
Density:	8.32 LB/GA
Vapor Pressure:	N/D
% VOC:	N/D
Odor Threshold	N/D
n-octanol Partition Coefficient	N/D
Decomposition Temperature	N/D

Section 10. Stability and Reactivity

Chemical Stability: Stable at normal temperatures and pressures.

Incompatibility with Various Substances: Strong oxidizers, Strong acids.

Hazardous Decomposition Products: Oxides of carbon, Oxides of nitrogen.

Possibility of Hazardous Reactions: None known.

Section 11. Toxicological Information

Chemical Name	Exposure	Type of Effect	Concentration	Species
2−Propanol	Oral	LD50	4396 MG/KG	Rat
	Dermal	LD50	12800 MG/KG	Rat
	Dermal	LD50	12800 MG/KG	Rabbit
Acetic acid	Oral	LD50	3310 MG/KG	Rat

Carcinogenicity Category

Component	Source	Code	Brief Description
2−Propanol	ACGIH	TLV−A4	Not classifiable as a human carcinogen.
	IARC	IARC−3	Unclassifiable as to carcinogenicity in humans
Acetic acid	N/E	N/E	N/E

Comments: None.

Section 12. Ecological Information

Species	Duration	Type of Effect	Test Results
Ceriodaphnia dubia	48h	LC50	1.8 mg/l
Fathead Minnow	96h	LC50	4.2 mg/l

Comments: None.

Section 13. Disposal Considerations

Dispose of in accordance with local, state and federal regulations.

Section 14. Transport Information

Controlling Regulation	UN/NA#:	Proper Shipping Name:	Technical Name:	Hazard Class:	Packing Group:
DOT	N/A	COMPOUND, INDUSTRIAL WATER TREATMENT, LIQUID	N/A	N/A	N/A

Note: N/A

Section 15. Regulatory Information

Inventory Status

United States (TSCA): All ingredients listed.
Canada (DSL/NDSL): All ingredients listed.

Federal Regulations

SARA Title III Rules

Sections 311/312 Hazard Classes

Fire Hazard: Yes
Reactive Hazard: No
Release of Pressure: No
Acute Health Hazard: Yes
Chronic Health Hazard: No

Other Sections

Component	Section 313 Toxic Chemical	Section 302 EHS TPQ	CERCLA RQ
2–Propanol	N/A	N/A	N/A
Acetic acid	N/A	N/A	5000

Comments: None.

State Regulations

California Proposition 65: None known.

Special Regulations

Component	States
2-Propanol	MN, NJ, PA, WA
Acetic acid	CA, DE, ID, MA, MN, NY, PA, WA, WI

International Regulations

Canada

WHMIS Classification: B3 (Combustible Liquid)

Controlled Product Regulations (CPR): This product has been classified in accordance with the hazard criteria of the Controlled Products Regulations (CPR) and the MSDS contains all the information required by the CPR.

Compliance Information

NSF: N/A

FDA/USDA/GRAS: N/A

KOSHER: This product has not been evaluated for Kosher approval.

FIFRA: N/A

Other: None

Comments: None.

Section 16. Other Information

HMIS Hazard Rating

Health:	1
Flammability:	2
Physical Hazard:	0
PPE:	X

Notes:

The PPE rating depends on circumstances of use. See Section 8 for recommended PPE.
The Hazardous Material Information System (HMIS) is a voluntary, subjective alpha–numeric symbolic system for recommending hazard risk and personal protection equipment information. It is a subjective rating system based on the evaluator's understanding of the chemical associated risks. The end–user must determine if the code is appropriate for their use.

Abbreviations

Abbreviation	Definition
<	Less Than
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ACGIH	American Conference of Governmental Industrial Hygienists
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N/A	Not Applicable
N/D	Not Determined
N/E	Not Established
OSHA	Occupational Health and Safety Dept
PEL	Personal Exposure Limit
STEL	Short Term Exposure Limit
TLV	Threshold Limit Value
TWA	Time Weight Average
UNK	Unknown

Prepared by: Product Compliance Department; ProductCompliance@chemtreat.com

Revision Date: September 14, 2015

Disclaimer

Olin
CHLOR ALKALI
PRODUCTS

MATERIAL SAFETY DATA

Sodium Hydroxide Solution, 50%

SECTION 1 – CHEMICAL PRODUCT AND COMPANY IDENTIFICATION

Δ

Manufacturer's name and address:	Supplier's name and address:
Olin Corporation – Chlor Alkali Products Division	PCI Chemicals Canada Company d/b/a Olin Chlor Alkali Products
CLEVELAND, TN OFFICE	MONTREAL, QC OFFICE
490 Stuart Road NE Cleveland, TN 37312-4918 U.S. • (423) 336-4850	2020 University, Suite 2190 Montreal, Quebec H3A 2A5 Canada • (514) 397-6100

Product Name: Sodium Hydroxide Solution, 50%

CAS#: 1310-73-2 **Preparation date (M/D/Y):** 10/02/08
MSDS Code: NaOH(50)-E **Revision date (M/D/Y):** 05/11/2010

Synonyms: Caustic soda liquid 50%, Soda lye, Lye, Liquid Caustic, Sodium Hydrate
Product Use: Neutralizing agent, industrial cleaner, pulping and bleaching, soap manufacturing

Emergency Contacts (24 hr.)

FOR INFORMATION REGARDING <u>ON SITE</u> CHEMICAL EMERGENCIES INVOLVING A SPILL OR LEAK, CALL

Δ **Canada: 1-800-567-7455**
U.S.: 1-800-424-9300 – CHEMTREC

SECTION 2 – COMPOSITION / INFORMATION ON INGREDIENTS

	Hazardous Ingredient(s)	% (w/w)	ACGIH	CAS NO.
Δ	Sodium Hydroxide	49 – 52	2 mg/m^3 (TLV-C)	1310-73-2

SECTION 3 – HAZARD IDENTIFICATION

Emergency Overview: Odorless, clear, non-volatile liquid. EXTREMELY CORROSIVE! Causes severe burns on contact. Can cause blindness, permanent scarring and death. Aerosols can cause lung injury – effects may be delayed. Highly reactive. Can react violently with water and numerous commonly encountered materials, generating enough heat to ignite nearby combustible materials. Contact with many organic and inorganic chemicals may cause fire or explosion. Reacts with some metals to liberate hydrogen gas, which can form explosive mixtures with air. Will not burn. Harmful to aquatic life. Read the entire MSDS for a more thorough evaluation of the hazards.

Potential Health Effects:

Δ **Routes of exposure:** Inhalation, skin contact, eye contact and ingestion.

Inhalation: Sodium hydroxide does not readily form a vapor and inhalation exposure is likely to occur as an aerosol. Due to its corrosive nature, sodium hydroxide aerosols could cause pulmonary edema (severe, life-threatening lung injury). The development of pulmonary edema may be delayed up to 48 hours after exposure. The early symptoms of pulmonary edema include shortness of breath and tightness in the chest.

Skin Contact: EXTREMELY CORROSIVE! Sodium hydroxide is capable of causing severe burns with deep ulceration and permanent scarring. It can penetrate to deeper layers of skin and corrosion will continue until removed. The severity of injury depends on the concentration (solutions) and the duration of exposure. Burns may not be immediately painful; onset of pain may be delayed minutes to hours. Several human studies and case reports describe the corrosive effects of sodium hydroxide. A 4% solution of sodium hydroxide, applied to a volunteer's arm for 15 to 180 minutes, caused damage which progressed from destruction of cells of the hard outer layer of the skin within 15 minutes to total destruction of all layers of the skin in 60 minutes. Solutions as weak as 0.12% have damaged healthy skin within 1 hour.

Eye Contact: EXTREMELY CORROSIVE! The severity of injury increases with the concentration, the duration of exposure, and the speed of penetration into the eye. Damage can range from severe irritation and mild scarring to blistering, disintegration, ulceration, severe scarring and clouding. Conditions, which affect vision such as glaucoma and cataracts, are possible late developments. In severe cases, there is progressive ulceration and clouding of eye tissue which may lead to permanent blindness.

Ingestion: EXTREMELY CORROSIVE! Severe pain; burning of the mouth, throat and esophagus; vomiting; diarrhea; collapse and possible death may result.

Chronic Effects: SKIN: Repeated or prolonged skin contact would be expected to cause drying, cracking, and inflammation of the skin (dermatitis).

Existing Medical Conditions Possibly Aggravated by Exposure: Asthma, bronchitis, emphysema and other lung diseases and chronic nose, sinus or throat conditions. Skin irritation may be aggravated in individuals with existing skin disorders.

Carcinogenicity: Sodium hydroxide is not classified as a carcinogen by ACGIH (American Conference of Governmental Industrial Hygienists) or IARC (International Agency for Research on Cancer), not regulated as a carcinogen by OSHA (Occupational Safety and Health Administration), and not listed as a carcinogen by NTP (National Toxicology Program).

Δ **Other important hazards:** Refer to TOXICOLOGICAL INFORMATION (Section 11) for additional information.

SECTION 4 – FIRST AID MEASURES

General: If you feel unwell, IMMEDIATELY seek medical advice (show this document).

Inhalation: Move victim to fresh air. If breathing is difficult, oxygen may be beneficial if administered by trained personnel, preferably on a doctor's advice. Give artificial respiration ONLY if breathing has stopped. Do not use mouth-to-mouth method if victim ingested or inhaled the substance: induce artificial respiration with the aid of a pocket mask equipped with a one-way valve or other proper respiratory medical device. Give Cardiopulmonary Resuscitation (CPR) only if there is no pulse AND no breathing. Obtain medical attention IMMEDIATELY. Symptoms of pulmonary edema can be delayed up to 48 hours after exposure.

Skin Contact: Immediately flush skin with lukewarm water for at least 20 minutes, and up to 60 minutes if necessary. Under lukewarm water remove contaminated clothing, jewelry, and shoes. If irritation persists, repeat flushing. Obtain medical attention immediately. Discard contaminated clothing and shoes in a manner which limits further exposure.

Eye Contact: Immediately flush eyes with lukewarm water for at least 20 minutes, and up to 60 minutes if necessary. Hold eyelids open during flushing. If irritation persists, repeat flushing. Obtain medical attention IMMEDIATELY. Do not transport victim until the recommended flushing period is completed unless flushing can be continued during transport.

Ingestion: DO NOT INDUCE VOMITING. If victim is alert and not convulsing, rinse mouth and give as much water as possible to dilute material (8 to 10 oz. or 240 to 300 mL). If spontaneous vomiting occurs, have victim lean forward with head down, rinse mouth and administer more water. IMMEDIATELY transport victim to an emergency facility.

SECTION 5 – FIRE FIGHTING MEASURES

Flammability	Not applicable. Not combustible (does not burn).
Flash Point (method)	Not applicable.
Flammable Limits (Lower)	Not applicable
Flammable Limits (Upper)	Not applicable
Auto Ignition Temperature	Not applicable
Combustion and Thermal Decomposition Products	Sodium oxide fumes
Rate of Burning	Not applicable
Explosive Power	Not applicable
Sensitivity to Mechanical Impact	Not sensitive ; stable material
Sensitivity to Static Charge	Not applicable

Fire and Explosion Hazards: Sodium hydroxide will not burn or support combustion. The reaction of sodium hydroxide with water and a number of commonly encountered materials (see Section 10) can generate sufficient heat to ignite nearby combustible materials. Sodium hydroxide can react with metals, such as aluminum, tin and zinc, to form flammable hydrogen gas.

Extinguishing Media: Use extinguishing media suitable for the surrounding fire. If water is used, care should be taken, since it can generate heat and cause spattering if applied directly to sodium hydroxide.

Special Information: Evacuate area and fight fire from a safe distance or a protected location. Approach fire from upwind. If possible, isolate materials not involved in the fire and protect personnel. Move containers from fire area if it can be done without risk.

Water can be used with extreme caution to extinguish a fire in an area where sodium hydroxide is stored. The water must not come into contact with the sodium hydroxide. Water can be used in flooding quantities as a spray or fog to keep fire-exposed containers cool and absorb heat. At high temperatures, fuming may occur, giving off a strong, corrosive gas. Do not enter without wearing specialized protective equipment suitable for the situation.

<u>Evacuation</u>: If tank or tank truck involved in a fire, ISOLATE and consider evacuation of one-half (1/2) mile (800 meters) in all directions.

Fire Fighting Protective Equipment: Firefighter's normal protective clothing (Bunker Gear) will not provide adequate protection. Chemical resistant clothing (e.g. chemical splash suit) and positive pressure self-contained breathing apparatus (MSHA/NIOSH approved or equivalent) may be necessary.

NOTE: Also see "Section 10 - Stability and Reactivity"

SECTION 6 – ACCIDENTAL RELEASE MEASURES

Spills, Leaks, or Releases:

- Restrict access to area until completion of clean up. Ensure trained personnel conduct clean up. Ventilate area.
- Wear adequate personal protective equipment (See Section 8). Do not touch spilled material.
- Prevent entry into sewers or waterways.
- Land spill of sodium hydroxide: Solutions should be contained by diking with inert material, such as sand or earth. Solutions can be recovered or carefully diluted with water and cautiously neutralized with acids such as acetic acid or hydrochloric acid.
- Water spill: Neutralize with dilute acid.
- Comply with Federal, Provincial/State and local regulations on reporting releases.

Deactivating Chemicals: Weak acid solutions (acetic, hydrochloric or sulfuric acid).

Waste Disposal Methods: Dispose of waste material at an approved waste treatment/disposal facility, in accordance with applicable regulations. Do not dispose of waste with normal garbage or to sewer systems.

Note - Clean-up material may be a RCRA Hazardous Waste on disposal.
- Spills are subject to CERCLA reporting requirements: RQ = 1000 lbs. (454 kg).

SECTION 7 – HANDLING AND STORAGE

Precautions: EXTREMELY CORROSIVE! Have emergency equipment (for fires, spills, leaks, etc.) readily available. Ensure all containers are labeled. Wear appropriate Personal Protection Equipment *(Refer to Section 8)*. People working with this chemical should be properly trained regarding its hazards and its safe use.

Handling Procedures and Equipment: Use smallest possible amounts in designated areas with adequate ventilation. Keep containers closed when not in use. Empty containers may contain hazardous residues. Avoid generating mists. Transfer solutions using equipment, which is corrosion-resistant. Cautiously, transfer into sturdy containers made of compatible materials. Never return contaminated material to its original container. Considerable heat is generated when diluted with water. Proper handling procedures must be followed to prevent vigorous boiling, splattering or violent eruption of the diluted solution. Never add water to a sodium hydroxide solution. **ALWAYS ADD SODIUM HYDROXIDE TO WATER** and provide agitation. When mixing with water, stir small amounts in slowly. Use cold water to prevent excessive heat generation.

Storage Requirements: Store in a cool, dry, well-ventilated area. Keep containers tightly closed when not in use and when empty. Protect from damage. Store away from incompatible materials such as strong acids, nitroaromatic, nitroparaffinic or organohalogen compounds. See Section 10 for Incompatibles. Use corrosion-resistant structural materials and lighting and ventilation systems in the storage area. Containers made of nickel alloys are preferred. Steel containers are acceptable if temperatures are not elevated. Nickel is the preferred metal for handling this product. Plastics or plastic-lined steel, or FRP tanks of Derakane vinyl ester resin may be suitable. Container contents may develop pressure after prolonged storage. Drums may need to be vented. Trained personnel should only perform venting.

Storage Temperature: Avoid freezing. Do not expose sealed containers to temperatures above 40°C (104°F).

SECTION 8 – EXPOSURE CONTROLS / PERSONAL PROTECTION

PREVENTIVE MEASURES

Recommendations listed in this section indicate the type of equipment which will provide protection against over exposure to this product. Conditions of use, adequacy of engineering or other control measures, and actual exposures will dictate the need for specific protective devices at your workplace.

Engineering Controls: Local exhaust ventilation should be applied wherever there is an incidence of point source emissions or dispersion of regulated contaminants in the work area. Ventilation control of the contaminant as close to its point of generation is both the most economical and safest method to minimize personnel exposure to airborne contaminants. The most effective measures are the total enclosure of processes and the mechanization of handling procedures to prevent all personal contact.

PERSONAL PROTECTIVE EQUIPMENT

Maintain eye wash fountain and quick-drench facilities in work area. Detailed requirements for personal protective equipment should be established on a site-specific basis.

Eye Protection: Wear full face-shield and chemical safety goggles when there is potential for contact.

Skin Protection: Wear appropriate personal protective clothing to prevent skin contact.

Guidelines for sodium hydroxide solutions, 30-70%:
RECOMMENDED (resistance to breakthrough longer than 8 hours): Butyl rubber; natural rubber, neoprene rubber, nitrile rubber, polyethylene, polyvinyl chloride, Teflon™, Viton™, Saranex™, 4H™, Barricade™, CPF 3™, Responder™, Trellchem HPS™, Tychem 10000™.
NOT RECOMMENDED for use (resistance to breakthrough less than 1 hour): Polyvinyl alcohol.

Respiratory Protection:
Up to 10 mg/m^3: Supplied Air Respirator (SAR) operated in a continuous-flow mode, eye protection needed; or full face-piece respirator with high-efficiency particulate filter(s); or powered air-purifying respirator with dust and mist filter(s), eye protection needed; or full face-piece Self-Contained Breathing Apparatus (SCBA); or full face-piece SAR.

Emergency or Planned Entry into Unknown Concentrations or IDLH Conditions: Positive pressure, full face-piece SAR; or positive pressure, full face-piece SAR with an auxiliary positive pressure SAR.

ESCAPE: Full face-piece respirator with high-efficiency particulate filter(s); or escape-type SCBA.

EXPOSURE GUIDELINES

PRODUCT: Sodium hydroxide:

	ACGIH Ceiling Exposure Limit (TLV-C)	2 mg/m^3
Δ	OSHA PEL-TWA	2 mg/m^3
	NIOSH IDLH	10 mg/m^3
	NIOSH REL:	C 2 mg/m^3

SECTION 9 – PHYSICAL AND CHEMICAL PROPERTIES

Alternate Name(s)	Caustic soda liquid 50%, Soda lye, Lye, Liquid Caustic, Sodium Hydrate
Chemical Name	Sodium hydroxide
Chemical Family	Alkali hydroxide
Molecular Formula	NaOH
Molecular Weight	40.01
Δ **Physical State and Appearance**	Clear-to-slightly turbid liquid
Odor	Odorless
pH	14.0 (Aqueous solution: 5%)
Vapor Pressure	0.2 kPa (1.5 mm Hg) at 20 °C (68°F) (50% solution)
Vapor Density (Air = 1)	Not applicable
Boiling Point	140 °C (284 °F) (50% solution)
Freezing Point	12 °C (53.6 °F) (50% solution)
Solubility (Water)	Soluble in all proportions
Specific Gravity	1.53 (50% solution) 15.5 °C (60°F)
Evaporation Rate	Not applicable
Viscosity (cp):	78.3 at 20 °C (68°F)
Bulk Density (lbs/cu ft):	95.5
Coefficient of Oil/Water Distribution	Essentially zero

SECTION 10 – STABILITY AND REACTIVITY

Chemical Stability: Stable at room temperature.

Hazardous Decomposition Products: Thermal decomposition: sodium oxide fumes

Conditions to Avoid: Water. Keep away from incompatibles.

Incompatibility with other Substances: Sodium hydroxide reacts vigorously, violently or explosively with many organic and inorganic chemicals, such as strong acids, nitroaromatic, nitroparaffin and organohalogen compounds, glycols and organic peroxides. Reacts violently with water generating significant heat and dangerously spattering corrosive sodium hydroxide. Violently polymerizes acetaldehyde, acrolein or acrylonitrile. Produces flammable and explosive hydrogen gas if it reacts with sodium tetrahydroborate or certain metals such as aluminum, tin, or zinc. Can form spontaneously flammable chemicals upon contact with 1,2- dichloroethylene, trichloroethylene or tetrachloroethane. Can produce carbon monoxide upon contact with solutions of sugars, such as fructose, lactose and maltose.

Corrosivity to Metals: Corrosive to aluminum, tin, zinc, copper, and most alloys in which they are present including brass and bronze. Corrosive to steel at elevated temperatures above 40°C(104°F).

Stability and Reactivity Comments: Slowly attacks glass at room temperature.

Hazardous Polymerization: Will not occur. However, it can induce hazardous polymerization of acetaldehyde, acrolein, and acrylonitrile.

SECTION 11 – TOXICOLOGICAL INFORMATION

For more toxicological information, refer to Section 3.

TOXICOLOGICAL DATA:

Toxicological Data: Sodium hydroxide

Toxicity data: LDLo - Lowest published lethal dose oral rabbit 500 mg /kg ; LD_{50} intraperitoneal mouse 40 mg/kg

Irritation data: Standard Draize Tests: 500 mg/24 hour(s) skin-rabbit severe; 400 µg eyes-rabbit mild; 1 percent eyes-rabbit severe;

Mutagenicity: There is no evidence of mutagenic potential.

Reproductive Effects: No information is available.

Teratogenicity and Fetotoxicity: No information is available.

Synergistic Materials: No information is available.

Skin and Respiratory Sensitization: No information is available.

Irritancy: Strong eye and skin irritant.

SECTION 12 – ECOLOGICAL INFORMATION

Ecotoxicological Information:
LC_{100} Cyprinus Carpio 180 ppm/24 hr @ 25°C (77°F)
TLm mosquito fish 125 ppm/96 hr (fresh water);
TLm Bluegill 99 mg/L/48 hr (tap water)

Persistence and Degradation: Degrades readily by reacting with natural carbon dioxide in the air. Does not bioaccumulate.

SECTION 13 – DISPOSAL CONSIDERATIONS

Review federal, state and local government requirements prior to disposal.

Do not dispose of waste with normal garbage, or to sewer systems.

Whatever cannot be saved for recovery or recycling, including containers, should be managed in an appropriate and approved waste disposal facility. Processing, use or contamination of this product may change the waste management options.

RCRA: Test waste material for corrosivity, D002, prior to disposal.

SECTION 14 – TRANSPORT INFORMATION

	TDG	DOT
Shipping Name	SODIUM HYDROXIDE, SOLUTION	Sodium hydroxide, solution
Hazard Class/Division	8	8
Identification No.	UN1824	UN1824
Packing Group:	II	II
Reportable Quantity	Not Applicable	RQ: 1000 lbs. (454 kg)
ERAP	NONE	Not Applicable

Δ **IATA/ICAO Shipping Description:** UN1824, Sodium hydroxide solution, Class 8, PG II is accepted for air transport.

Δ **For Chemical Emergencies <u>in Transportation</u> Requiring Activation of Olin 24 Hour Emergency Response Plan Call:**
U.S. 1-800-424-9300 – Chemtrec
Canada 1-800-567-7455

SECTION 15 – REGULATORY INFORMATION

Δ **CANADIAN INFORMATION:**

This product has been classified in accordance with the hazard criteria of the CPR (Controlled Products Regulations) and this MSDS (Material Safety Data Sheet) contains all the information required by the CPR.

Controlled Products Regulations (WHMIS) Classification:
E: Corrosive Material

CEPA / Canadian Domestic Substances List (DSL): Y

WHMIS Ingredient Disclosure List: Meets criteria for disclosure at 1% or greater.

Δ **USA INFORMATION:**

OSHA Classification: Hazardous by definition of Hazard Communication Standard (29 CFR 1910.1200)

SARA Regulations sections 313 and 40 CFR 372: N

SARA Hazard Categories, SARA SECTIONS 311/312 (40 CFR 370.2):
ACUTE: Y
CHRONIC: N
FIRE: N
REACTIVE: Y
SUDDEN RELEASE: N
OSHA PROCESS SAFETY (29 CFR 1910.119): N

CERCLA SECTION 103 (40 CFR 302.4): Y

Reportable Quantity (RQ) under CERCLA: 1000 lbs. (454 kg)

TSCA Inventory Status: Y

This product does not contain nor is it manufactured with ozone depleting substances.

Δ **EUROPEAN ECONOMIC COMMUNITY (EEC) INFORMATION:**

EINECS Number: 215-185-5

CALIFORNIA PROP 65 COMPONENTS:
This product is not listed, but it may contain elements known to the State of California to cause cancer or reproductive toxicity as listed under Proposition 65 State Drinking Water and Toxic Enforcement Act. For additional information, contact Olin Technical Services (800-299-6546)

SECTION 16 – OTHER INFORMATION

Δ **The information contained herein is offered only as a guide to the handling of this specific material and has been prepared in good faith by technically knowledgeable personnel. It is not intended to be all-inclusive and the manner and conditions of use and handling may involve other and additional considerations. No warranty of any kind is given or implied and Olin will not be liable for any damages, losses, injuries or consequential damages that may result from the use of or reliance on any information contained herein. This Material Safety Data Sheet is valid for three years.**

Revision Indicators:
Δ In the left margin indicates a revision or addition of information since the previous issue.

National Fire Protection Association (NFPA) Rating
Hazardous Materials Identification System (HMIS) Rating

Δ

	NFPA	HMIS
HEALTH	3	3
FIRE	0	0
REACTIVITY / INSTABILITY	1	1
SPECIAL HAZARDS	N/Ap	N/Ap

4 = Extreme/Severe
3 = High/Serious
2 = Moderate
1 = Slight
0 = Minimum
~~W~~ = Water Reactive
OX = Oxidizer
* = Chronic health hazard

Δ **REFERENCES:**

1. Chemlist, STN Database, Chemical Abstract Service, 1999
2. "CHEMINFO", CCOHS, Canadian Centre for Occupational Health and Safety, Hamilton, Ontario, Canada, (2008).
3. DOSE, Royal Society of Chemistry, Aug 27, 1999.
4. HSDB- Hazardous Substances Data Bank, CCOHS, 2008.
5. RTECS-Registry of Toxic Effects of Chemical Substances, On-line search, Canadian Centre for Occupational Health and Safety RTECS database, Doris V. Sweet, Ed., National Institute for Occupational Safety and Health, U.S. Dept. of Health and Human Services, Cincinnati, Entry Update/ August 2007.
6. "2008 Threshold Limit Values and Biological Exposure Indices", American Conference of Government Industrial Hygienists, 2008.
7. Merck, 11th Edition, 1989

Δ **LEGEND:**

ACGIH	- American Conference of Governmental Industrial Hygienists
AFFF	- Aqueous Film Forming Foam
AIHA	- American Industrial Hygiene Association
CAS #	- Chemical Abstracts Service Registry Number
CERCLA	- Comprehensive Environmental Response, Compensation, and Liability Act
CFR	- Code of Federal Regulations
DOT	- Department of Transportation
EINECS	- European Inventory of Existing Chemical Substances
EPA	- Environmental Protection Agency
ERAP	- Emergency Response Assistance Plan
IATA	- International Air Transportation Association
ICAO	- International Civil Aviation Organization
FRP	- Fiberglass Reinforced Plastic
HMIS	- Hazardous Materials Identification System
IARC	- International Agency for Research on Cancer
IDLH	- Immediately Dangerous to Life and Health
LC50	- The concentration of material in air expected to kill 50% of a group of test animals
LD_{50}	- Lethal Dose expected to kill 50% of a group of test animals
MSHA	- Mine Safety and Health Administration
N/Ap	- Not Applicable
N/Av	- Not Available
NFPA	- National Fire Protection Association
NIOSH	- National Institute for Occupational Safety and Health
NTP	- National Toxicology Program
OSHA	- Occupational Safety & Health Administration
PEL	- Permissible Exposure Limit
PVC	- Polyvinyl chloride
RCRA	- Resource Conservation and Recovery Act
SARA	- Superfund Amendments and Reauthorization Act of the U.S. EPA
STEL	- Short Term Exposure Limit
TDG	- Transportation of Dangerous Goods Act/Regulations
TLV	- Threshold Limit Value
TSCA	- Toxic Substances Control Act
TWA	- Time Weighted Average
WEEL	- Workplace Environmental Exposure Level
WHMIS	- Workplace Hazardous Materials Identification System

Prepared by: Olin
(514) 397-6100

SECTION 1: IDENTIFICATION

Product Identifier

Product Name: Sulfuric Acid, 70-100%

Formula: H_2-O_4-S

Intended Use of the Product

Use of the Substance/Mixture: Industrial use.

Name, Address, and Telephone of the Responsible Party

Manufacturer

CHEMTRADE LOGISTICS INC.
155 Gordon Baker Road
Suite 300
Toronto, Ontario M2H 3N5
For MSDS Info: (416) 496-5856
www.chemtradelogistics.com

Emergency Telephone Number

Emergency number : Canada: CANUTEC +1-613-996-6666 / US: CHEMTREC +1-800-424-9300
Chemtrade Emergency Contact: (866) 416-4404
For Chemical Emergency, Spill, Leak, Fire, Exposure, or Accident, call CHEMTREC – Day or Night

SECTION 2: HAZARDS IDENTIFICATION

Classification of the Substance or Mixture

Classification (GHS-US)

Acute Tox. 2 (Inhalation:dust,mist)	H330
Skin Corr. 1A	H314
Eye Dam. 1	H318
Carc. 1A	H350

Label Elements

GHS-US Labeling

Hazard Pictograms (GHS-US) :

GHS05 GHS06 GHS08

Signal Word (GHS-US) : Danger

Hazard Statements (GHS-US) : H314 - Causes severe skin burns and eye damage
H318 - Causes serious eye damage
H330 - Fatal if inhaled
H350 - May cause cancer

Precautionary Statements (GHS-US) : P201 - Obtain special instructions before use
P202 - Do not handle until all safety precautions have been read and understood
P260 - Do not breathe fume, mist, vapors, spray
P264 - Wash hands and forearms thoroughly after handling
P271 - Use only outdoors or in a well-ventilated area
P280 - Wear eye protection, face protection, protective gloves, protective clothing
P284 - Wear respiratory protection
P301+P330+P331 - IF SWALLOWED: rinse mouth. Do NOT induce vomiting
P303+P361+P353 - IF ON SKIN (or hair): Remove/Take off immediately all contaminated clothing. Rinse skin with water/shower
P304+P340 - IF INHALED: Remove person to fresh air and keep at rest in a position comfortable for breathing
P305+P351+P338 - If in eyes: Rinse cautiously with water for several minutes. Remove contact lenses, if present and easy to do. Continue rinsing

P308+P313 - If exposed or concerned: Get medical advice/attention
P310 - Immediately call a POISON CENTER or doctor/physician
P320 - Specific treatment is urgent (see Section 4)
P363 - Wash contaminated clothing before reuse
P403+P233 - Store in a well-ventilated place. Keep container tightly closed
P405 - Store locked up
P501 - Dispose of contents/container according to local, regional, national, and international regulations

Other Hazards

Other Hazards Not Contributing to the Classification: Not available

Unknown Acute Toxicity (GHS-US) Not available

SECTION 3: COMPOSITION/INFORMATION ON INGREDIENTS

Substances

Name	Product identifier	% (w/w)	Classification (GHS-US)
Sulfuric acid	(CAS No) 7664-93-9	70 - 100	Met. Corr. 1, H290 Skin Corr. 1A, H314 Eye Dam. 1, H318 Carc. 1A, H350

Full text of H-phrases: see section 16

SECTION 4: FIRST AID MEASURES

Description of First Aid Measures

General: IF exposed or concerned: Get medical advice/attention. If you feel unwell, seek medical advice (show the label where possible).

Inhalation: Using proper respiratory protection, immediately move the exposed person to fresh air. Keep at rest and in a position comfortable for breathing. Give oxygen or artificial respiration if necessary. Seek immediate medical advice. Symptoms may be delayed.

Skin Contact: Remove/Take off immediately all contaminated clothing. Rinse immediately with plenty of water (for at least 15 minutes). Seek medical attention immediately if exposure is severe. Obtain medical attention if irritation develops or persists. Wash contaminated clothing before reuse.

Eye Contact: Immediately rinse with water for a prolonged period (at least 15 minutes) while holding the eyelids wide open. Seek medical attention immediately if exposure is severe. Obtain medical attention if irritation develops or persists.

Ingestion: If swallowed, do not induce vomiting: seek medical advice immediately and show this container or label.

Most Important Symptoms and Effects Both Acute and Delayed

General: Corrosive. Causes burns.

Inhalation: Causes severe respiratory irritation if inhaled. Symptoms may include burning of nose and throat, constriction of airway, difficulty breathing, shortness of breath, bronchial spasms, chest pain, and pink frothy sputum. Contact may cause immediate severe irritation progressing quickly to chemical burns. May cause pulmonary edema. Symptoms may be delayed.

Skin Contact: Contact may cause immediate severe irritation progressing quickly to chemical burns.

Eye Contact: Contact may cause immediate severe irritation progressing quickly to chemical burns. Can cause blindness.

Ingestion: May cause burns or irritation of the linings of the mouth, throat, and gastrointestinal tract. Swallowing a small quantity of this material will result in serious health hazard.

Chronic Symptoms: Repeated or prolonged inhalation may damage lungs. Prolonged and repeated contact will eventually cause permanent tissue damage.

Indication of Any Immediate Medical Attention and Special Treatment Needed

If medical advice is needed, have product container or label at hand.

SECTION 5: FIRE-FIGHTING MEASURES

Extinguishing Media

Suitable Extinguishing Media: Use extinguishing media appropriate for surrounding fire.

Unsuitable Extinguishing Media: Do not get water inside containers. Do not apply water stream directly at source of leak. Do not use a heavy water stream. A direct water stream will cause violent splattering and generation of heat.

Special Hazards Arising From the Substance or Mixture

Fire Hazard: Not flammable. Under conditions of fire this material may produce: Sulphur oxides.
Explosion Hazard: Product is not explosive.
Reactivity: Reacts with water.

Advice for Firefighters

Precautionary Measures Fire: Not available
Firefighting Instructions: Keep upwind. Use water spray or fog for cooling exposed containers.
Protection During Firefighting: Firefighters must use full bunker gear including NIOSH-approved positive-pressure self-contained breathing apparatus to protect against potential hazardous combustion and decomposition products.
Hazardous Combustion Products: Sulphur oxides.
Other information: Do not allow run-off from fire fighting to enter drains or water courses.

Reference to Other Sections

Refer to section 9 for flammability properties.

SECTION 6: ACCIDENTAL RELEASE MEASURES

Personal Precautions, Protective Equipment and Emergency Procedures

General Measures: Do not breathe vapour or mist.

For Non-Emergency Personnel

Protective Equipment: Use recommended respiratory protection. Wear suitable protective clothing, gloves and eye/face protection.
Emergency Procedures: Stop leak if safe to do so. Eliminate ignition sources. Evacuate unnecessary personnel. Ventilate area. Keep upwind.

For Emergency Personnel

Protective Equipment: Use recommended respiratory protection. Wear suitable protective clothing, gloves and eye/face protection.
Emergency Procedures: Stop leak if safe to do so. Eliminate ignition sources. Evacuate unnecessary personnel. Ventilate area.

Environmental Precautions

If spill could potentially enter any waterway, including intermittent dry creeks, contact the U.S. COAST GUARD NATIONAL RESPONSE CENTER at 800-424-8802. In case of accident or road spill notify CHEMTREC at 800-424-9300 (in USA) or CANUTEC at 613-996-6666 (in Canada). In other countries call CHEMTREC at (International code) +1-703-527-3887.

Methods and Material for Containment and Cleaning Up

For Containment: Contain any spills with dikes or absorbents to prevent migration and entry into sewers or streams.
Methods for Cleaning Up: Ventilate area. Small quantities of liquid spill: take up in non-combustible absorbent material and shovel into container for disposal. Collect absorbed material and place into a sealed, labelled container for proper disposal. Practice good housekeeping - spillage can be slippery on smooth surface either wet or dry. Liquid spill: neutralize with powdered limestone or sodium bicarbonate.

Reference to Other Sections

SECTION 7: HANDLING AND STORAGE

Precautions for Safe Handling

Hygiene Measures: Handle in accordance with good industrial hygiene and safety procedures. Emergency eye wash fountains and safety showers should be available in the immediate vicinity of any potential exposure. Wash contaminated clothing before reuse.

Conditions for Safe Storage, Including Any Incompatibilities

Storage Conditions: Detached outside storage is preferable.
Incompatible Materials: Reducing agents. Organic materials. Alkalis. Moisture.
Storage Area: Store in dry, cool area. Store in a well-ventilated place. Keep away from combustible materials.

Specific End Use(s) Not available

SECTION 8: EXPOSURE CONTROLS/PERSONAL PROTECTION

Control Parameters

Sulfuric acid (7664-93-9)		
Mexico	OEL TWA (mg/m^3)	1 mg/m^3
USA ACGIH	ACGIH TWA (mg/m^3)	0.2 mg/m^3
USA OSHA	OSHA PEL (TWA) (mg/m^3)	1 mg/m^3
USA NIOSH	NIOSH REL (TWA) (mg/m^3)	1 mg/m^3
USA IDLH	US IDLH (mg/m^3)	15 mg/m^3

Alberta	OEL STEL (mg/m^3)	3 mg/m^3
Alberta	OEL TWA (mg/m^3)	1 mg/m^3
British Columbia	OEL TWA (mg/m^3)	0.2 mg/m^3 (Thoracic, contained in strong inorganic acid mists)
Manitoba	OEL TWA (mg/m^3)	0.2 mg/m^3
New Brunswick	OEL STEL (mg/m^3)	3 mg/m^3
New Brunswick	OEL TWA (mg/m^3)	1 mg/m^3
Newfoundland & Labrador	OEL TWA (mg/m^3)	0.2 mg/m^3
Nova Scotia	OEL TWA (mg/m^3)	0.2 mg/m^3
Nunavut	OEL STEL (mg/m^3)	3 mg/m^3
Nunavut	OEL TWA (mg/m^3)	1 mg/m^3
Northwest Territories	OEL STEL (mg/m^3)	3 mg/m^3
Northwest Territories	OEL TWA (mg/m^3)	1 mg/m^3
Ontario	OEL TWA (mg/m^3)	0.2 mg/m^3
Prince Edward Island	OEL TWA (mg/m^3)	0.2 mg/m^3
Québec	VECD (mg/m^3)	3 mg/m^3
Québec	VEMP (mg/m^3)	1 mg/m^3
Saskatchewan	OEL STEL (mg/m^3)	0.6 mg/m^3
Saskatchewan	OEL TWA (mg/m^3)	0.2 mg/m^3
Yukon	OEL STEL (mg/m^3)	1 mg/m^3
Yukon	OEL TWA (mg/m^3)	1 mg/m^3

Exposure Controls

Appropriate Engineering Controls: Ensure adequate ventilation, especially in confined areas.

Personal Protective Equipment: Face shield. Gas mask at concentration in the air > > TLV. Corrosionproof clothing.

Materials for Protective Clothing: Acid-resistant clothing.

Hand Protection: Impermeable protective gloves.

Eye Protection: Face shield.

Skin and Body Protection: Wear suitable protective clothing. Chemical resistant suit. Rubber apron, boots.

Respiratory Protection: Use a NIOSH-approved respirator or self-contained breathing apparatus whenever exposure may exceed established Occupational Exposure Limits.

Environmental Exposure Controls: Emergency eye wash fountains and safety showers should be available in the immediate vicinity of any potential exposure.

SECTION 9: PHYSICAL AND CHEMICAL PROPERTIES

Information on Basic Physical and Chemical Properties

Physical State	:	Liquid
Appearance	:	Clear,Colorless to Amber,Oily
Odor	:	Pungent.
Odor Threshold	:	Not available
pH	:	0.3
Relative Evaporation Rate (butylacetate=1)	:	Not available
Melting Point	:	10.56 °C (51.08 °F)
Freezing Point	:	Not available
Boiling Point	:	290 °C (554 °F)
Flash Point	:	Not available
Auto-ignition Temperature	:	Not available
Decomposition Temperature	:	Not available
Flammability (solid, gas)	:	Not available
Lower Flammable Limit	:	Not available
Upper Flammable Limit	:	Not available
Vapor Pressure	:	0.00027 - 0.16 kPa at 25 °C (77 °F)

Relative Vapor Density at 20 °C	:	3.4
Relative Density	:	Not available
Specific Gravity	:	1.84 g/l
Solubility	:	Water: Miscible
Partition coefficient: n-octanol/water	:	Not available
Viscosity	:	Not available
Explosion Data – Sensitivity to Mechanical Impact	:	Not expected to present an explosion hazard due to mechanical impact.
Explosion Data – Sensitivity to Static Discharge	:	Not expected to present an explosion hazard due to static discharge.

SECTION 10: STABILITY AND REACTIVITY

Reactivity: Reacts with water.

Chemical Stability: Stable at standard temperature and pressure.

Possibility of Hazardous Reactions: Hazardous polymerization can occur in contact with certain incompatible materials.

Conditions to Avoid: Protect from moisture.

Incompatible Materials: Avoid contact with most metals, carbides, hydrogen sulfide, turpentine, organic acids, combustibles (wood, paper, cotton) and other organic and readily oxidized materials.

Hazardous Decomposition Products: Under conditions of fire this material may produce: Sulphur oxides.

SECTION 11: TOXICOLOGICAL INFORMATION

Information on Toxicological Effects - Product

Acute Toxicity: Fatal if inhaled.

LD50 and LC50 Data:

Sulfuric Acid, 70-100%	
ATE US (dust, mist)	0.05000000 mg/l/4h

Skin Corrosion/Irritation: Causes severe skin burns and eye damage.
pH: 0.3

Serious Eye Damage/Irritation: Causes serious eye damage.
pH: 0.3

Respiratory or Skin Sensitization: Not classified

Germ Cell Mutagenicity: Not classified

Teratogenicity: Not available

Carcinogenicity: May cause cancer.

Specific Target Organ Toxicity (Repeated Exposure): Not classified

Reproductive Toxicity: Not classified

Specific Target Organ Toxicity (Single Exposure): Not classified

Aspiration Hazard: Not classified

Symptoms/Injuries After Inhalation: Causes severe respiratory irritation if inhaled. Symptoms may include burning of nose and throat, constriction of airway, difficulty breathing, shortness of breath, bronchial spasms, chest pain, and pink frothy sputum. Contact may cause immediate severe irritation progressing quickly to chemical burns. May cause pulmonary edema. Symptoms may be delayed.

Symptoms/Injuries After Skin Contact: Contact may cause immediate severe irritation progressing quickly to chemical burns.

Symptoms/Injuries After Eye Contact: Contact may cause immediate severe irritation progressing quickly to chemical burns. Can cause blindness.

Symptoms/Injuries After Ingestion: May cause burns or irritation of the linings of the mouth, throat, and gastrointestinal tract. Swallowing a small quantity of this material will result in serious health hazard.

Chronic Symptoms: Repeated or prolonged inhalation may damage lungs. Prolonged and repeated contact will eventually cause permanent tissue damage.

Information on Toxicological Effects - Ingredient(s)

LD50 and LC50 Data:

Sulfuric acid (7664-93-9)	
LD50 Oral Rat	2140 mg/kg
LC50 Inhalation Rat (mg/l)	510 mg/m³ (Exposure time: 2 h)

Sulfuric acid (7664-93-9)	
IARC Group	1

SECTION 12: ECOLOGICAL INFORMATION

Toxicity Not classified

Sulfuric acid (7664-93-9)	
LC50 Fish 1	500 mg/l (Exposure time: 96 h - Species: Brachydanio rerio [static])

Persistence and Degradability

Sulfuric Acid, 70-100%	
Persistence and Degradability	Product is biodegradable.

Bioaccumulative Potential

Sulfuric Acid, 70-100%	
Bioaccumulative Potential	Not expected to bioaccumulate.

Sulfuric acid (7664-93-9)	
BCF fish 1	(no bioaccumulation)

Mobility in Soil Not available

Other Adverse Effects Not available

SECTION 13: DISPOSAL CONSIDERATIONS

Sewage Disposal Recommendations: This material is hazardous to the aquatic environment. Keep out of sewers and waterways.
Waste Disposal Recommendations: Dispose of waste material in accordance with all local, regional, national, and international regulations.

SECTION 14: TRANSPORT INFORMATION

14.1 In Accordance with DOT

Proper Shipping Name : SULFURIC ACIDwith more than 51 percent acid
Hazard Class : 8
Identification Number : UN1830
Label Codes : 8
Packing Group : II
ERG Number : 157

14.2 In Accordance with IMDG

Proper Shipping Name : SULPHURIC ACID
Hazard Class : 8
Identification Number : UN1830
Packing Group : II
Label Codes : 8
EmS-No. (Fire) : F-A
EmS-No. (Spillage) : S-B

14.3 In Accordance with IATA

Proper Shipping Name : SULPHURIC ACID
Packing Group : II
Identification Number : UN1830
Hazard Class : 8
Label Codes : 8
ERG Code (IATA) : 8L

14.4 In Accordance with TDG

Proper Shipping Name : SULPHURIC ACIDwith more than 51 per cent acid
Packing Group : II
Hazard Class : 8
Identification Number : UN1830

Label Codes : 8

SECTION 15: REGULATORY INFORMATION

US Federal Regulations

Sulfuric Acid, 70-100%	
SARA Section 311/312 Hazard Classes	Immediate (acute) health hazard Delayed (chronic) health hazard Reactive hazard

Sulfuric acid (7664-93-9)	
Listed on the United States TSCA (Toxic Substances Control Act) inventory Listed on SARA Section 302 (Specific toxic chemical listings) Listed on SARA Section 313 (Specific toxic chemical listings)	
SARA Section 302 Threshold Planning Quantity (TPQ)	1000
SARA Section 313 - Emission Reporting	1.0 % (acid aerosols including mists, vapors, gas, fog, and other airborne forms of any particle size)

US State Regulations

Sulfuric Acid, 70-100%()

Sulfuric acid (7664-93-9)	
U.S. - California - Proposition 65 - Carcinogens List	WARNING: This product contains chemicals known to the State of California to cause cancer.

Sulfuric acid (7664-93-9)
U.S. - Massachusetts - Right To Know List U.S. - New Jersey - Right to Know Hazardous Substance List U.S. - Pennsylvania - RTK (Right to Know) - Environmental Hazard List U.S. - Pennsylvania - RTK (Right to Know) List

Canadian Regulations

Sulfuric Acid, 70-100%	
WHMIS Classification	Class D Division 1 Subdivision A - Very toxic material causing immediate and serious toxic effects Class E - Corrosive Material

Sulfuric acid (7664-93-9)	
Listed on the Canadian DSL (Domestic Substances List) inventory. Listed on the Canadian Ingredient Disclosure List	
WHMIS Classification	Class D Division 1 Subdivision B - Toxic material causing immediate and serious toxic effects Class D Division 2 Subdivision A - Very toxic material causing other toxic effects Class E - Corrosive Material

This product has been classified in accordance with the hazard criteria of the Controlled Products Regulations (CPR) and the SDS contains all of the information required by CPR.

SECTION 16: OTHER INFORMATION, INCLUDING DATE OF PREPARATION OR LAST REVISION

Other Information : This document has been prepared in accordance with the SDS requirements of the OSHA Hazard Communication Standard 29 CFR 1910.1200.

GHS Full Text Phrases:

Acute Tox. 2 (Inhalation:dust,mist)	Acute toxicity (inhalation:dust,mist) Category 2
Carc. 1A	Carcinogenicity Category 1A
Eye Dam. 1	Serious eye damage/eye irritation Category 1

Met. Corr. 1	Corrosive to metals Category 1
Skin Corr. 1A	Skin corrosion/irritation Category 1A
H290	May be corrosive to metals
H314	Causes severe skin burns and eye damage
H318	Causes serious eye damage
H330	Fatal if inhaled
H350	May cause cancer

Party Responsible for the Preparation of This Document
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APPLICATION FOR PERMIT TO DRILL PROPOSED GEOTHERMAL WELL KAPOHO STATE 15 ON RESERVED LANDS, KAPOHO, PUNA HAWAII

Complying with Department of Land and Natural Resources (DLNR) Administrative Rule, Title 13, Chapter 183, Section 65, Puna Geothermal Venture (PGV) herewith makes application for a Permit-to-Drill for approval by the Hawaii Board of Land and Natural Resources.

1. **Applicant:**

Puna Geothermal Venture
P.O. Box 30
14-3860 Kapoho Pahoa Road
Pahoa, Hawaii 96778-0030
(808) 965-6233

PUNA GEOTHERMAL VENTURE

By: ______________________________
Michael L. Kaleikini
Plant Manager
Puna Geothermal Venture

Owner of Mining Rights:

Kapoho Land Partnership

Land Owner:

Kapoho Land and Development Company, Limited

2. **Proposed Well Designation:**

Kapoho State 15 (KS-15) off Wellpad B.

3. A tax key map, designating the approximate location of the drill site for KS-15 off Wellpad B located on State Geothermal Mining Lease R-2; a topographic map, designating the approximate surface elevation at Wellpad B of 743 feet above mean sea level, and a PGV Project map, designating the relative locations of KS-15 and Wellpad B are contained in Attachment I.

4. The proposed PGV Project geothermal well KS-15 has been designed to intersect near-vertical fractures, approximately 5500 feet to approximately 7500 feet true vertical depth (TVD). Previously approved in the Plan-of-Operation approved March 10, 1989, by the Board of Land and Natural Resources. At least one other drilling target was for the purpose of reinjecting geothermal fluids and non-condensible gases from, the operation of the power plant.

5. A detailed Summary-of-Drilling Procedures is enclosed in Attachment II.

6. A Summary-of-Drilling Reporting Criteria is enclosed in Attachment III.

7. A description of Lithologic ("Mud") Logging Procedures is enclosed in Attachment IV.

9. A multi-well drilling bond ($250,000) has previously been filed with the State of Hawaii.

10. Puna Geothermal Venture agrees to perform such drilling as outlined in this application and agrees to maintain the well in accordance with Title 13, Chapter 183, State of Hawaii, and all Federal and County geothermal regulations.

KS-15 DRILLING PERMIT: ATTACHMENT I

PUNA GEOTHERMAL VENTURE
APPLICATION TO DRILL PROPOSED KAPOHO STATE 15
A GEOTHERMAL WELL

I. General Information

a.	Well Designation:	Kapoho State 15
b.	Location:	TMK 1-04-01:19
	Kapoho, Puna, Hawaii (Figure 1)	
c.	State Geothermal Mining Lease:	R-2
d.	Owner of Mineral Rights:	Kapoho Land Partnership
e.	Subleased to:	Puna Geothermal Venture
f.	Operator:	Puna Geothermal Venture

II. Well Data

a.	Well Site:	Well Pad B
b.	Well map coordinates:	154° 6' 4.73"W 19° 28'45"N
c.	Well Type:	Development Well
d.	Surface Elevation:	743 feet AMSL (Figure 3)
e.	Projected Depth:	Approximately +/- 7500 feet True Vertical Depth (TVD)
f.	Target:	Fractured basalt below 4000 feet Measured Depth (MD)

III. Geology

Depth (MD):	Formation:
0 - 627 ft.	Unsaturated subaerial basalt flows and intercalated cinder scoria.
627 ft.	Water Table
627 - 3000 ft.	Saturated subaerial basalt flows and intercalated cinder scoria; rare dikes.
3000 - 4000 ft.	Interbedded hyaloclastite deposits and minor subaerial grading into submarine basalt flows; localized dike swarms.
4000 - 6500 ft.	Submarine basalt flows cross-cut by basalt dikes and possibly high-permeability, near-vertical fractures.
6500 - TD	Basaltic dike complex with locally recognizable submarine basalt flows.

KS-15 DRILLING PERMIT: ATTACHMENT II

PUNA GEOTHERMAL VENTURE
(Except as noted, all depths are referenced to KB.)

KS-15 DRILLING PROGRAM,

Hole Profile and Sizes:
36” hole and 30” casing to 85’
26” hole and 22” casing to +/-1050’, 114.8#, Grade B, Welded
20” hole and 16” casing to +/- 2300’, 84#, L-80, SL Boss Conn
14-3/4” hole and 11-3/4” casing to +/- 5100’, 65#, L 80, SL GS Conn
10-5/8” hole and 8-5/8” liner to TD +/- 7500’, 36#,T 95, Atlas Bradford Conn .

1. Install 30" conductor at 85'.
   1.1. Notify county two weeks prior to setting conductor.
   1.2. Core 48” hole and cement conductor in place with redi mix concrete.
   1.3. Drill rat hole as directed and install cover.

2. Move in Imina Ikaika rig and associated equipment.
   2.1. Notify DLNR 24 hours prior to rig up.
   2.2. Rig up and install top drive. Install sump-less drilling system.
   2.3. Install direct communications between rig floor, tool pusher and company man.
   2.4. Comply with all sections of the Plan of Operations that pertain to drilling.
   2.5. Instruct drillers to remain on the floor at all times during drilling operations.
   2.6. Adhere to the Drilling Reporting Criteria.
   2.7. Provide DLNR with copies of the daily tour sheets.
   2.8. Ensure that Supervisors, Tool pushers, Drillers and Derrick men have current well control training and that all personal have H2S safety training.
   2.9. Hold pre-spud meeting - discuss chain of command and well control issues.

3. Install conductor with rotating head and flow line to separator. Rig transfer pump to move separator underflow to shale shakers. Have three welders available.
   3.1. Rig up air compressor.
   3.2. Rig up H2S monitors and all safety equipment.
   3.3. Provide high volume water supply to the mud pits.
   3.4. Follow mud-logging procedures as directed by well site geologist.
   3.5. Be ready to pump defoamer as needed.

4. Drill 26" hole to 700'$\underline{+}$.
   4.1. Use 26" bit, 25-1/2” shorty stab and with mud motor, 25-1/2” stabs at 30’ & 60’ and two shock subs in BHA. Strap all tools from mud motor down to bit.
   4.2. Catch 10' grab samples from drill cuttings and monitor for hydrothermal alteration whenever circulation permits. Check returns, if any, for salinity and chlorides.
   4.3. Keep hole as straight as possible. Run a magnetometer with the Mud motor to find out the proximity to KS-2 well.
   4.4. Continue drilling with lime treated water when lost circulation is encountered and add high volume water injection into the annulus.
      4.4.1. Use lime treated mud and LCM pills as needed to keep hole clean.
      4.4.2. Run drilling jars in all assemblies.
      4.4.3. At first sign of repeated fill, switch to foamed water using, foam and viscosifier as needed.
      4.4.4. Increase foam and viscosifier as needed to clean hole.
      4.4.5. Remember to displace string with water before making connections.
   4.5. At 700' rig up and pump clean water sample for DLNR.
      4.5.1. Notify DLNR 24 hours prior to sampling.
      4.5.2. Collect a representative water sample of ground water at 650'$\underline{+}$.

4.5.3. Run a submersible pump on drill pipe, strapping electric line to drill pipe.

5. Continue drilling 26" hole to 1050' +. Casing shoe will be set in low permeability rock below major lost circulation zones. The casing will be set shallow if high temperatures or hydrothermal alteration is encountered.
   5.1. Use water and conventional rotary or mud motor drilling as appropriate.
      5.1.1. Run drilling jars in all assemblies.
      5.1.2. The key to getting loose in 26" hole is being able to go or jar down. To avoid stuck pipe problem make sure to not get shut down near bottom.
   5.2. Set casing high if rubble zone is encountered below 900'.
      5.2.1. Set and polish cement plug on bottom if formation is not competent.
   5.3. Keep hole as straight as possible.
   5.4. Monitor well for flow or gases.
   5.5. Circulate hole clean and make wiper run with stiff assembly, leave safety sub out of the reaming assembly.
      5.5.1. Circulate hole clean after wiper trip and measure out of hole.
      5.5.2. Use aerated fluid (foam) as needed to clean out any fill.
   5.6. Cut off 30" drilling nipple as needed and prepare chute for redimix.

6. Rig up and run 1050'+ of 22", 0.500" wall, Grade B, butt welded casing (114.81 ppf) equipped as follows. Run jet down float shoe and tag in float collar with latch in plug. Centralize 10' above shoe, 40' above shoe, first set of pad eyes and every set thereafter. Have three welders available.
   6.1. Weld casing in 80' lengths prior to running with pad eyes on each length.
   6.2. Use three welders and follow supplied welding procedure.
   6.3. Fabricate a stinger and hose to make up on top drive to run inside of 22".
   6.4. Fill casing with line hung off of top drive only as needed to wash to bottom. Do not set down hard on fill, wash to bottom.
   6.5. Have casing sized to remain off bottom.

7. Trip in hole with centralizer on drill pipe, rabbit drill pipe as it is run. Stop 2' from float collar, circulate 2 barrels per minute for 2 minutes, shut off pump and stab into 22" shoe.

8. Pump 25 barrels of water ahead followed by 20 barrels of sodium silicate and 5 barrels of water spacer. Pump 90 barrels of lead slurry followed by 40 barrels tail slurry. Drop latch down plug and displace cement. Stutter squeeze tail cement and displacement.
   8.1. Monitor returns and surface pressures throughout job.
   8.2. Center casing, land on 30" and WOC.
   8.3. Be prepared to do a top job with Redi Mix. Order out at least 30 yards Redi Mix. Contact Glover and arrange prepayment. Add sodium silicate to annulus as needed. (One barrel sodium silicate to each yard of redi mix cement)
   8.4. Have at least 20 cubic yards of # 9 crushed blue rock on hand to fill annulus through lost circulation zones if required.
   8.5. WOC a minimum of 12 hours on initial cement job before drilling out.

9. Nipple up BOPE. Have two welders available.
   9.1. Cut off 22" casing and install pre fabricated 22" spool with 21-1/4" -2M flange and side outlets.
   9.2. Install 21-1/4"-2M annular preventer and pitcher nipple.
   9.3. Notify DLNR 24 hours prior to testing. Test BOPE and casing and have DLNR witness and approve test. Make sure annular holds at low pressure 200 psi (for foam cementing).
   9.4. Log test results on tour sheet and morning report. Test casing to 700 psi.
   9.5. Periodic BOPE drills will be conducted and logged on tour sheets.
   9.6. Install and test high efficiency mud coolers. Run coolers if and as needed.

10. Make up 20" slick BHA. Clean out cement and shoe with mud (55 vis and with 3 ppb micronized cellulose) and circulate clean.
   10.1. If circulation is lost at the bottom of the cement, stop, treat the contamination out of the mud and start adding water loss control agents. Wash out the fill to bottom, stop and condition mud to lower water loss to ~10.

10.2. Perform shoe integrity test (0.67 psi/ft) and squeeze if necessary. Play the plug job by the ear. If the cement is going away on its own, don't do any more than clear the DP. If the hole fills up and stands pretty full after the job, close the annular and squeeze a few barrels at low pressure. If the hole doesn't fill after the samples get firm, run OEDP to tag and set another plug. If the hole fills, run the BHA. Stop cleaning out right below the shoe and do an integrity test using the LOT procedure and then clean out and drill ahead.
10.3. If 22" casing runs to bottom, discuss running mud motor assembly.

11. Make up BHA and drill 20" hole to 2300'±.
    11.1. Use straight-hole mud motor and 20" stabilized bit and BHA. Use safety subs, shock tools, and drilling jars in all BHA's. Run safety subs below jars.
    11.2. Strap all tools below the motor. Pick up clean shock tool. Rotate drill string about 50 RPM.
    11.3. Keep watch for any communication with the old KS-8 underground blow out flow.
    11.4. Cement off lost circulation zones if LCM isn't effective.
    11.5. Catch 10' grab samples of drill cuttings. Keep close watch on samples for changes in mineralogy indicative of a high temperature geothermal reservoir.
    11.6. Check mud for increased salinity and chlorides.
    11.7. Monitor well for increase of decrease in flow rates and gasses.
    11.8. Be prepared to set casing if there are any signs of encountering a high temperature reservoir.
    11.9. Do not shut pumps off on bottom, pump for 2-3 minutes picking up the string to clear the bit and then turn your pumps off.

12. Run high pump volumes to properly clean hole.
    12.1. Run all solids control equipment. Run two centrifuges. Use coarse shale shaker screens if necessary to handle 850-1000 gpm circulation rates.
    12.2. Keep a close eye on the sump-less system. Run mud cleaner at all times.
    12.3. Keep mud plastic viscosity and gels as low as possible with at least a 1/32" mud cake.
    12.4. The drilling mud to have 4 ppb of micronized cellulose and 2 sxs/hr of Mil Seal. The sweeps (30 barrels every 30 min) incase of losses to be made of 10 ppb of Chekloss, 2 ppb of Mil Seal and 4 ppb of Nut Plug.
    12.5. Incase of not be able to keep mud mixing upto the mud loss rate, pump an LCM pill on bottom, pull out to the shoe and mix mud.

13. At casing point, circulate hole clean and make wiper trip to shoe.
    13.1. Measure out of hole. Keep hole full.
    13.2. Monitor well and be sure well takes proper amount of fluid.

14. Rig up and run 16", 84#, L-80, SL Boss casing equipped as follows; Jet down Float shoe, float collar with stab in latch down plug. Run crossover joint at surface. Centralize 10' above shoe, on first, second and third collar. Centralize every third collar thereafter. Do not use bow type centralizers inside of the 22" casing. While measuring the casing lengths with premium threads, measure from the pin end to the top of coupling and delete the fixed make length (Eg on SL Boss delete 5.4")
    14.1. Run landing joint with pick up nubbin. Have casing sized to remain off bottom.
    14.2. Use thread protectors. Run casing at slow speeds to prevent down surge.
    14.3. Fill casing with mud while running. Keep monitoring well. Center casing in rotary table by closing the annular BOPE with the casing in slips but most of the casing weight hanging in the blocks. Keep hole full.
    14.4. Modify circulating swage as needed to circulate and work pipe in 9" bales. Move top drive grabber to transport position if necessary. Make up circulating swage, work casing, circulate and condition hole prior to running inner string drill pipe.
    14.5. Run in hole with 5" drill pipe for the inner string cement job to the top of the float collar. Pump 2 barrels to clear the drill pipe prior to stabbing in. Circulate with one pump at 30 spm.

15. Inner string conventional foamed Cement job to cement 16" casing with the following schedule: 1) 20 barrels fresh water 2) 20 barrels foamed fresh water spacer 3) 20 barrels of foamed flo check 4) 3 barrels of foamed fresh water . Followed by 387 ± barrels foamed cement (50 barrels Excess unfoamed cement, 250 barrels of Lead Cement 13.0 ppg, 25 barrels of Latex unfoamed cement and 57 barrels of conventional tail slurry (with latex across interval from shoe to above 1800'). Use 67 barrels accelerated

slurry for foamed top squeeze (tail slurry with 3% calcium chloride and foamer added, no nitrogen). Use detailed checklist and valve diagram for job.

15.1. Pump a constant rate, variable density foam design with an initial density of about 6 ppg at 100 psi surface and a final density of about 12 ppg down hole after pumping tail and top squeeze.
15.2. Rig up to take returns through choke line. Install low pressure gage on choke line and second valve.
15.3. Pump foam cement until good clean foam cement returns to surface and keep the choke fully open, and annulus closed.
15.4. Drop wiper plug and start displacement and bump plug with low pressure.
15.5. Switch the lines and pump top squeeze into 22" x 16" annulus. Discontinue top squeeze if annular pressure exceeds 250 psi.
15.6. Monitor annular pressure. Keep annulus closed and wash out choke and lines. Begin pulling out the stab in string after the displacement has been completed. WOC until top squeeze has taken an initial set and built some compressive strength before beginning nipple down.
15.7. WOC at least 8 hours before landing casing.

16. Back off landing joint and cut off 22"casing. Weld bottom ring of annular pack off assembly to 22" and weld thread-o-let to 22" casing below pack off. Install pack off, valve on outlet and install slip on weld 16"-5M casing head flange using standard API welding procedure.

17. Install a 16"-5M spacer spool, 16"-5m mud cross with 4-1/16" outlets,16"-5m double gate (bottom – blind, upper 3-1/2" pipe rams) , and 16"-5m flow diverter, with a 7"-5m HCR valve and rupture disk to Blooie line. Install 16"-5m double gate (bottom – blind, upper 5" pipe rams), 16"-5m annular preventer, 16" -3M rotating head, choke and kill lines, blooie line and muffler. Have three welders available. Also, connect water and abatement lines to the blooie line as shown in the attachments. Install and check all monitoring equipment, including the driller's assistant. WOC at least 16 hours prior to pressure testing casing.

17.1. Notify DLNR 24 hours prior to BOPE test. Log all test results and approvals on tour sheet and morning report.
17.2. All pushers, drillers and derrick men will be trained in the use of monitoring equipment. Training will be logged on the tour sheets.
17.3. Test casing to 1500 psi or 70% of burst, whichever is less.
17.4. Test BOPE to 1500 psi, test annular to 700 psi.
17.5. BOPE test sequence using Halliburton: Function test, pump water through the whole stack and choke manifold. Test the lower blind ram, outer choke manifold valves, inner choke manifold valves, HCR, the upper pipe rams. Test to 500 psi for 10 min and then increase to 1500 psi.

18. Use 14-3/4" bit on BHA to clean out cement and floats, use motor if appropriate.

18.1. Run in hole, test Annular and 5" pipe rams, run in 1 joint of 3-1/2" DP and test 3-1/2" Pipe rams.
18.2. Clean out at least 1' below shoe and circulate clean with mud.
18.3. Perform shoe integrity test to 0.65 psi per foot and squeeze if necessary. RIH with OEDP. Clean hole clean and pump LCM with micronized cellulose. Pump 50 barrels of water spacer, pump 20 barrels of 15 ppg tail cement with 3% CaCl2, displace the cement with mud. Pull up 2 stands, pump the nerd ball to wipe the drill pipe clean of cement, stutter squeeze.
18.4. Use safety subs, shock tools, and drilling jars in all BHA's. Run clean shock sub with every new bit. Run safety subs below jars.

19. Drill 14-3/4" hole to 5100'±. Casing point will be in the cap rock above the reservoir as determined by the well site geologist using the "Plan of Operations" criteria.

19.1. ***Keep hole straight.*** Survey every 200 to 300' and run MRT's with surveys.
19.2. Raise the mud weight while drilling to provide sufficient hydrostatic pressure to prevent flow if required.
19.3. Catch 10' grab samples of drill cuttings.
    19.3.1. Keep close watch on all mud properties. Raise MBT to approximately 15 ppb in lower part of the 14-3/4" hole.
    19.3.2. Monitor well for flow volume changes and for any gas flow.
    19.3.3. Keep close watch on samples for changes in mineralogy indicative of a high temperature geothermal reservoir.
    19.3.4. Be prepared to set casing if there are any signs of encountering a high temperature

reservoir.

19.4. Cement off all major lost circulation zones. Use a T in cementing line and stuff a foam ball into the cement line before displacing plug. If necessary, reduce mud weight.

19.5. Turn on one mud cooler when flow line temperature reaches 150 °F. Turn on second mud cooler when flow line temperature reaches 150 °F again.

19.6. If well indicates flow or pressure during trips, cool hole with both coolers on and then recheck well for flow.

20. Circulate clean and strap out. Run locked BHA with button reamer and under-gage stabs to ream hole.

21. Rig up and run 11-3/4" casing. Equip casing with jet down guide shoe and single float collar with latch in wiper plug. The casing and all equipment will be 11-3/4", 65#,L-80 mod, SL GS.
    21.1. Use thread protectors. Run casing at slow speeds to prevent down surge. Fill casing with mud while running.
    21.2. Keep monitoring well. Keep hole full. Have casing sized to remain off bottom prior to running.
    21.3. Centralize casing as follows, 10' from shoe, 1st, 2nd, 3rd and every 4th collar to the 16" shoe, use positive centralizers inside of the casing.
    21.4. Modify circulating swage as needed to circulate and work pipe in 9” bales. Move top drive grabber to transport position if necessary.
    21.5. Circulate to cool hole. Drop cementing centralizer from surface on sash cord, be prepared to Pick up BOPE and centralize casing with centralizer in 16" casing head. BOPE stack weighs 87,000 pounds.

22. Reverse circulate cement casing with 15 barrels foamed water, 15 barrels foamed sodium silicate, 3 barrels foamed water and foamed cement as per program with latex across interval from 1800’ to 2400’. Plus 20 barrels conventional tail slurry, retarded if necessary. Use 17 barrels of accelerated slurry for non-foamed top squeeze (tail slurry with 3% calcium chloride added).
    22.1. Run drill pipe (rabbit pipe), install drill pipe pack off on casing, circulate casing with cool mud and stab into shoe.
    22.2. Reverse circulate casing through drill pipe and condition hole for cement. Rig up choke manifold with low-pressure gage to take returns from drill pipe.
    22.3. Pump foamed cement into annulus until very good foamed cement returns to surface through drill pipe. Design the foam job with constant density stages and lead cement with a 4 ppg surface density at 50 psi back pressure.
    22.4. Shut in annulus. Pump tail slurry through drill pipe, displacing foamed cement out of drill pipe. Drop and displace wiper and bump plug if possible. Hold at least 100 psi back pressure on annulus throughout the process.
    22.5. Bleed cement from annulus through choke as required to maintain proper densities while pumping and displacing tail slurry. Pump foamed cap slurry into annulus as soon as tail slurry is in place (with foamer only, no nitrogen).
    22.6. Check floats. Sting out. POH. WOC.

23. Cut off casing and install expansion spool. Remove 16” BOPE stack in two pieces. Change out liners in pumps while installing expansion spool.
    23.1. Use BX type API rings and hydraulic torque wrench on all studs attached to the expansion spool (including those on wing valves). Do not re-use X type rings!
    23.2. Use power plant (Power Piping Code) pattern and tighten all studs to maximum specifications, use maximum allowable rope packing in seal area.
    23.3. Test expansion spool pack off to 2500 psi with NITROGEN!!!

24. Re-install BOP stack for 11-3/4" casing including 12”-1500 master valve with remote actuator and 12”-1500 by 16”-5M DSA below the 16”-5M BOPE stack. Also connect water and abatement lines to the blooie line as shown in the attachments. Install and check all monitoring equipment, including the driller’s assistant. WOC a minimum of 16 hours prior to installing the stack.
    24.1. Use RX-58 type API ring between master valve and expansion spool.
    24.2. Use power plant (Power Piping Code) pattern and tighten all studs to maximum specifications when installing master valve.
    24.3. Notify DLNR 24 hours prior to testing BOPE.

24.4. Test casing to 1500 psi or 70% of burst, whichever is less.
24.5. Test BOPE to 1500 psi and annular to 700 psi.
24.6. Test to be witnessed and approved by DLNR. Log all test results and approvals on tour sheet and morning report.

25. Make up 10-5/8” steerable mud motor and MWD to drill out shoe with mud. Run integral NMDC/MWD, don’t run retrievable MWD.
    25.1. Circulate into hole.
    25.2. Drill at least 1' of new hole. Circulate hole clean.
    25.3. Perform shoe integrity test (use LOT procedure) and squeeze if necessary.

26. Drill 10-5/8" hole to 7500’ +/- TVD or until sufficient production is encountered.
    26.1. Directionally drill the 10-5/8" hole. See the attached directional program. Rotate through all slide sections prior to making connections.
    26.2. Run both mud coolers.
    26.3. Keep close watch on mud properties. Weight up if needed to control well.
    26.4. Be sure all monitoring equipment is in good working order. Catch 10' grab samples of drill cuttings.
    26.5. Watch closely for flow or loss and for changes in mineralogy indicative of high temperature geothermal reservoir.
    26.6. If well indicates flow or shut in pressure during trips, cool hole with both mud coolers and recheck well.
    26.7. Stroke master valve from full open to close and function test BOPE on every trip.
    26.8. If practical, pull motor and MWD on first dull bit after direction and angle have been established. Complete drilling with locked BHA.
        26.8.1. Survey at intervals not to exceed 200’. Run MRT's with all surveys.
        26.8.2. Run clean shock sub with every new bit.
    26.9. Drill blind with sweeps and water into the annulus. Pull to the shoe at the first sign of trouble and call for orders. Do not stay in the open hole without a sufficient water supply.

NOTE: An 8-5/8" liner may be run and cemented if the 11-3/4" shoe is deemed too shallow or formation is unstable.

27. T.D. will be kelly down after total loss circulation occurs or when sufficient rat hole has been drilled below the permeable zones.
    27.1. If the well is drilled blind, pump water into annulus in addition to fluid through bit and tools. Use micronized cellulose with sweeps to clean hole.
    27.2. Place well on kill line at 4 barrels per minute water and strip out.
    27.3. Monitor well while POH, and maintain vacuum.
    27.4. Upon reaching shoe, POH laying down drill pipe and tools.

    27.5. Rig up and run 8-5/8", T-95, 35.14 ppf, Atlas Bradford HDL flush joint casing. Size liner to provide 100' of blank casing overlap with shoe. Run a K-55 SOW float shoe.
    27.6. Make up an L-80 liner hanger crossed over to AB HDL flush joint with swab cups below setting kelly on DP with string float and set on rack or stand back.
    27.7. All joints will have a 15’ blank interval below the box so that the annular preventer can be effective if the well needs to be shut in while running casing.
    27.8. Install an integral safety sub and pick up nubbin in every joint of casing prior to picking out of the V door. These will have to be designed and built.
    27.9. Ensure that the integral safety sub and pick up nubbin can be used with the 9” bales. Move top drive grabber to transport position if necessary.
    27.10. Leave valve on safety subs open to monitor for flow while running casing.
    27.11. Make up single slip J Slot liner hanger and run liner in hole on drill pipe. Run string float in drill pipe above landing hanger and monitor for flow.
    27.12. Set liner on bottom and release. POH keeping well dead as above.

28. If the liner is set on fill, make up and RIH a 7-1/2” minimal bottom hole assembly and drill out shoe.
    28.1. Clean out any fill below shoe and drill ahead as needed to encounter additional productive intervals. (The liner will follow the bit to the bottom of the 10-5/8” hole if it was set on fill and stop there.)

28.2. Multiple bit runs can be made through this liner.
28.3. A second liner could be nested inside of this one if necessary. It would need to be 6-5/8” or smaller and tubing or small drill pipe would be required to clean out inside of the casing or drill blow the casing.

29. After the shoe has been drilled out, or if no additional drilling or clean out activity is planned, drive on hold down slips with or without a packer will be run and set in the top of the liner to prevent it from coming up hole.
    29.1. Close master valve. Keep well dead with county water or start to heat up with flow from a production well. Install temporary H2S monitor.
    29.2. Install second master after rig is skidded or before moving off as appropriate..

30. Tighten all flanges on wellhead equipment and valves using power piping procedure and hydraulic torque wrenches.

31. There may be a rig on flow test. If so a separate procedure will be provided.
    31.1. Tear out BOPE and install second 12"-1500 series master valve.
    31.2. Install companion flange and swab valve.
    31.3. Install Barton recorder and dial gauge to monitor well pressure.

32. Rig down and move rig out. Release well to 0&M.

Alternate 8-5/8” cemented liner program

1. If the 11-3/4” shoe is determined to have been set to shallow or the formation below the shoe is unstable an 8-5/8” liner may be run and cemented.
    1.1. Run 8-5/8", 44#, L-80, SL BOSS casing. Size liner to provide 200' of lap and remain off bottom. Run a K-55 SOW float shoe and a K-55 SOW double box float collar 60’ above the shoe. Centralize 10' above shoe, 1st, 2nd and every 4th collar thereafter.
    1.2. Make up an L-80 liner hanger with cementing pack off crossed over to SL Boss prior to running liner.
    1.3. Fill casing and keep hole full while running casing.
    1.4. Monitor well closely. Use care while running hanger through BOPE not to damage slips.

2. Cement 8-5/8" liner as follows. Circulate and condition hole prior to cementing. Hang liner and break nut prior to cementing.
    2.1. Cement with 10 barrels water ahead plus 10 barrels sodium silicate and 5 barrels water followed by115 barrels lead slurry and 21 barrels tail slurry, retarded as needed. Drop dart and displace cement. Do not pump more than 5 barrels excess displacement to bump plug.
    2.2. Release liner and POH. RIH with and 10-5/8" bit and circulate out excess cement with water to approximately 80' above liner top.
    2.3. WOC and clean out cement to top of liner as soon as the cement is firm enough to drill. Trip for 7-5/8" tools. Clean out the liner to within 20' of the shoe with water.
    2.4. Test liner lap to a 0.9 psi/ft gradient. Squeeze liner lap and retest if necessary.

3. Fill hole with mud and drill out. Make 3' to 5' of new hole. Circulate clean and perform a shoe integrity test. Use LOT procedure. Squeeze cement and repeat test if required.
    3.1. A 7-5/8" hole will be drilled below the 8-5/8" liner using the same procedure as outlined for drilling 10-5/8" hole above.
    3.2. A 6-5/8” liner will have to be run below this liner.

Alternate 6-5/8” pre-perforated drill in liner

1. Rig & run pre-perforated 6-5/8”, 32#, L-80, SL BOSS shouldered connection casing.
    1.1. Use a drill in shoe and bit on bottom.
    1.2. Run at least 100’ blank casing on top of liner and perforate casing to shoe.
    1.3. Size perforations to be smaller than the minimum annular space between stabbed in tubing and casing ID.
    1.4. Run sufficient casing to reach TD with 100’ of over lap with the last shoe.

2. Rig up to circulate and drill with liner.
    2.1. Run tubing inside of liner, tag up and space out with pup joints.
    2.2. Make up Hydraulic Drill In Tool and Expansion Joint to tubing then into liner.
    2.3. Make up bumper sub and pick up and run in hole on drill pipe.

3. Drill liner in as needed to reach sufficient production or TD.
    3.1. Keep top of liner inside of 8-5/8" casing shoe.
    3.2. Use appropriate pump rates and fluids to clean hole.

4. At TD release from liner and POH.
    4.1. Use appropriate well control after encountering production.
    4.2. Hydraulic release with dropped ball.
    4.3. Straight pull out of liner with all tools and tubing.
    4.4. Circulate as needed to pull tubing out of the liner.

5. RIH with mechanical Steel Seal Adaptor on bumper sub.
    5.1. Engage top of liner with adaptor and rotate to release seal.
    5.2. Compress seal with string weight and rotate out of adaptor.
    5.3. POH and lay down tools and tubing.

DIRECTIONAL DRILLING PLAN FOR KS-15

PUNA GEOTHERMAL VENTURE

Location: HAWAII | Field: PUNA | Facility: PUNA
Slot: KS-15 (Pad B) | Well: KS-15 | Wellbore: KS-15 (P4)

BAKER HUGHES INTEQ

Plot reference wellpath is KS-15 (Plan#4)	
True vertical depths are referenced to Rig on KS-15 (Pad B) (RT)	Grid System: NAD27 / TM Hawaii State Planes, Zone 1 (5101), US feet
Measured depths are referenced to Rig on KS-15 (Pad B) (RT)	North Reference: True north
Rig on KS-15 (Pad B) (RT) to Mean Sea Level: 743 feet	Scale: True distance
Mean Sea Level to Mud line (Facility: PUNA): 0 feet	Depths are in feet
Coordinates are in feet referenced to Slot	Created by: bondkenl on 4/11/2011

Targets

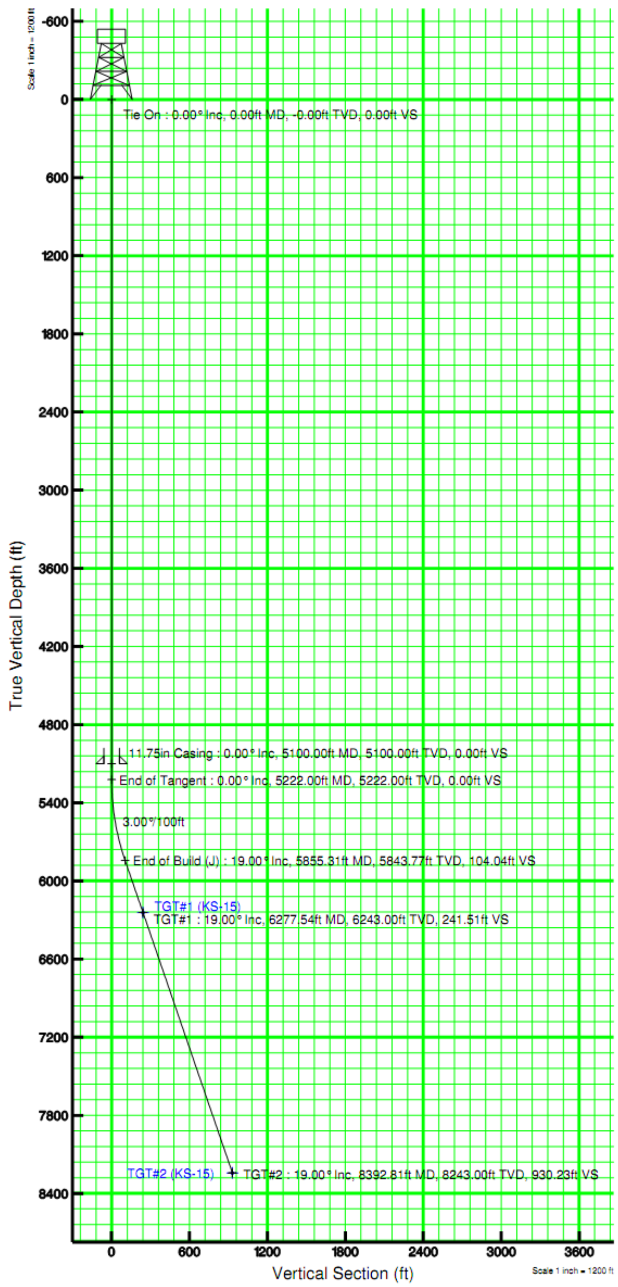
Name	MD (ft)	TVD (ft)	Local N (ft)	Local E (ft)	Grid East (USft)	Grid North (USft)	Latitude	Longitude
TGT#1 (KS-15)	6277.54	6243.00	215.00	-110.00	683209.17	221964.07	19°26'37.662"N	154°58'05.572"W
TGT#2 (KS-15)	8392.81	8243.00	829.00	-422.00	682895.28	222577.10	19°26'43.748"N	154°58'08.832"W

Bottom Hole Location

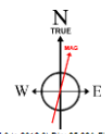
MD (ft)	Inc (°)	Az (°)	TVD (ft)	Local N (ft)	Local E (ft)	Grid East (srv ft)	Grid North (srv ft)	Latitude	Longitude
8392.81	19.004	333.221	8243.00	829.00	-422.00	682895.28	222577.10	19°26'43.748"N	154°58'08.832"W

Well Profile Data

Design Comment	MD (ft)	Inc (°)	Az (°)	TVD (ft)	Local N (ft)	Local E (ft)	DLS (°/100ft)	VS (ft)
Tie On	0.00	0.000	332.904	0.00	0.00	0.00	0.00	0.00
End of Tangent	5222.00	0.000	332.904	5222.00	0.00	0.00	0.00	0.00
End of Build (J)	5855.31	18.999	332.904	5843.77	92.63	-47.39	3.00	104.04
End of Tangent (J)	6277.54	18.999	332.904	6243.00	215.00	-110.00	0.00	241.51
End of 3D Arc	8392.81	19.004	333.221	8243.00	829.00	-422.00	0.00	930.23

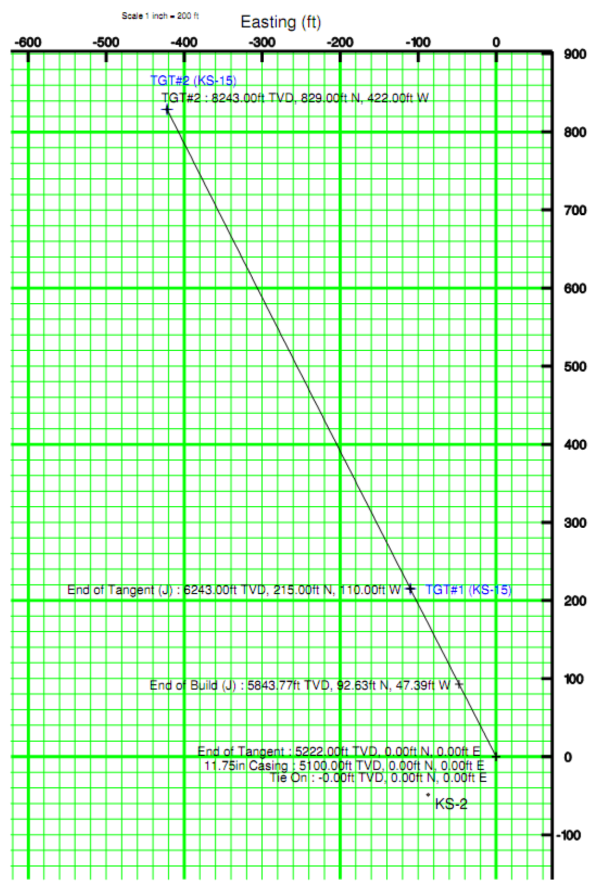


Azimuth 333.02° with reference 0.00 N, 0.00 E



BGGM (1945.0 to 2012.0) Dip: 35.93° Field: 34660.6 nT
Magnetic North is 9.69 degrees East of True North (at 4/11/2011)

To correct azimuth from Magnetic to True add 9.69 degrees
For example: if the Magnetic North Azimuth = 90 degs, then the Grid North Azimuth = 90 + 9.69 = 99.69



PROPOSED MUD PROGRAM:

26” hole from 85’ to 1050’ +/-
Drill with aerated mud

20” hole from 1050’ to 2300’ +/-
Drill with low pH gel mud with the following properties: mud weight 8.7-9.2 ppg, viscosity 50-65, PV 10-15, YP 20-30, Gel 5-10, Fluid loss 10-20, pH 8. Sweeps on connections as needed.

14-3/4” hole from 2300’ to 5100’ +/-
Drill with gel mud for high temperature with the following properties: mud weight 8.7-9.2 ppg, viscosity 45-55, PV 10-15, YP 10-15, Gel 4-8, Fluid loss 7-10, pH 10

10-5/8” hole from 5100’ to TD 7500’+/-.
Drill with gel mud for high temperature with the following properties: mud weight 8.7-9.2 ppg, viscosity 45-55, PV 10-15, YP 10-15, Gel 4-8, Fluid loss 7-10, pH 10. In the production zone, through the total loss section, drill with water and hi vis sweeps on connections

KS-15 DRILLING PERMIT: ATTACHMENT III
PUNA GEOTHERMAL VENTURE
DRILLING REPORTING CRITERIA

1. The Drilling Supervisor shall report to the PGV Drilling Engineer or his designated relief on the day-to-day operations.

2. As closely as possible, the Drilling Supervisor will follow the drilling program for a particular well as provided by the Drilling Engineer. There will be changes in the drilling program as the well progresses, and these changes must be discussed with the Drilling Engineer before action is taken.

3. A mud program will be outlined in the Drilling Program, and this program should be followed as closely as possible. The Drilling Supervisor shall have ample latitude to change the mud program as dictated by the actual drilling conditions.

4. Historical drilling data have been developed regarding the Puna Geothermal Project, and this data should be used to the best advantage in drilling wells within the project.

5. In and out mud temperatures and maximum recording temperatures will be logged on the IADC tower report.

6. When drilling, special precautions must be taken when encountering any lost circulation zones or drilling breaks.

7. If a drilling break is encountered while drilling, then the pipe should be picked up to properly place tool joint and bottoms up should be circulated around. The PGV Drilling Supervisor should be immediately notified along with the contractor's supervisor. A temperature survey should be run whenever a drilling break is encountered. An interpretation of the survey should be made by the Drilling Engineer before drilling further. It is important not to drill ahead with excessive temperature in the mud returns.

8. The driller should also note in the IADC tower report any gains or losses in the mud pit volume. Any significant mud loss should be reported to the PGV Supervisor(s) and the Contractor's Supervisor(s). If any continuous or significant mud gain is encountered, then the driller should pick up the pipe and check for flow and notify the supervisors. If flow is observed, then the well will be shut in immediately.

9. Based on past experience at the Puna Geothermal Project, it is imperative that constant supervision of the well be accomplished once drilling is undertaken. PGV Supervisors will be in charge of all activities on location. PGV Supervisors will report to the PGV Drilling Engineer or Drilling Manager.

10. Drilling Supervisors will spend sufficient time together at the rig during change-out to exchange information on the current activities. Drilling Supervisors will be on the floor, on the pump truck, in the wireline unit, etc. for all critical operations.

11. The Drilling Engineer will be responsible for engineering programs with input from the Drilling Supervisors. The Drilling Engineer will also advise and assist the Drilling Managers and Supervisors.

12. Contractor's supervisors will report to the Drilling Supervisor on location. They will also be on the floor during all crew changes.

13. Reporting procedures for crews will be the responsibility of the drilling contractor. Drillers will log all rig operations on the IADC daily tower report, including the depths of all work performed. Rig crew will assist service company personnel as directed by the contractor's supervisor.

KS-15 DRILLING PERMIT: ATTACHMENT IV
PUNA GEOTHERMAL VENTURE
PROCEDURES FOR LITHOLOGIC ("MUD") LOGGING

While drilling, depths are recorded on a Bristol chart (a circular chart matching time versus depth). As a single joint is drilled, each ten-foot interval (i.e., 100, 110, 120, etc.) is marked and labeled on the chart. A lag time (the interval of time, measured in minutes, required to circulate drilling fluids from the bit to the surface) is calculated based on hole size and pump rates and a marker is set to indicate when a marked depth reaches the surface.

When drilling fluids containing suspended drill cuttings derived from a given interval reach the surface, such fluids travel down the flow line and over the mesh shaker screens. After the latest ten-foot interval has accumulated at the base of the shakers, the mud logger obtains a representative sample of the drill cuttings. The sample is then washed of the drilling fluid. One portion of the cuttings, the wet sample, is placed in a plastic bag and the remainder is dried and bagged in sample sets.

A small amount is retained to view under a stereomicroscope. The cuttings from each ten-foot interval are then visually and physically evaluated. Detailed written descriptions of each ten-foot interval are entered on work sheets which are subsequently summarized onto the mud log data sheet. The lithologic descriptions include rock type, color, texture, hardness, structural characteristics, alteration (if any) and secondary mineralization.

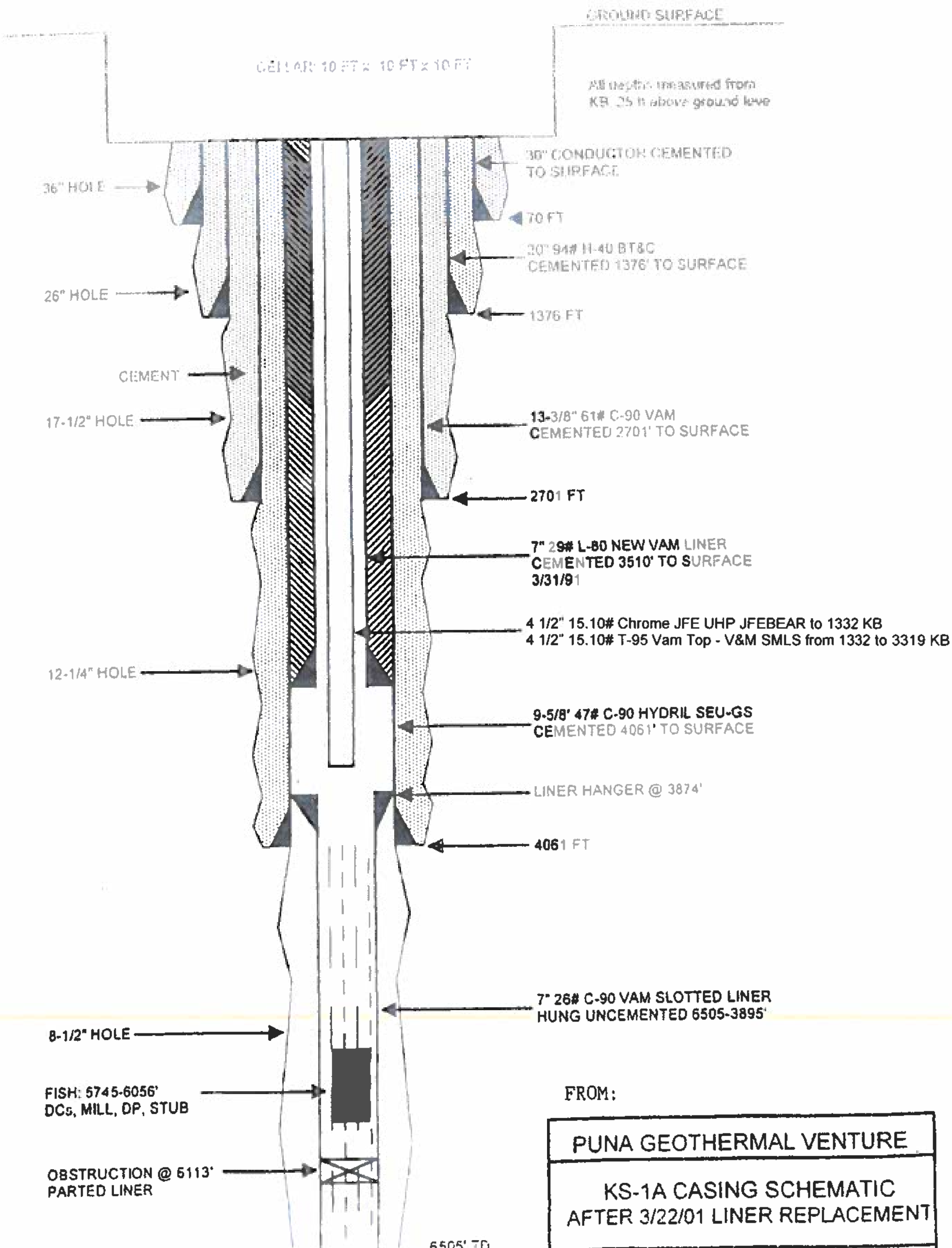
ATTACHMENT L – CONSTRUCTION PROCEDURES

In the future, geothermal wells may be drilled in the Area of Review and included within this Permit, as described in Section IX of the UIC Permit Application Form. The drilling procedures for future geothermal wells are expected to be similar in most respects to those in the attached "Application for Permit to Drill Proposed Geothermal Well Kapoho State 15 on Reserved Lands, Kapoho, Puna, Hawaii." Although not included in this attachment, procedures specified in PGV's current Plan of Operations are also made a part of the drilling procedure.

ATTACHMENT M – CONSTRUCTION DETAILS

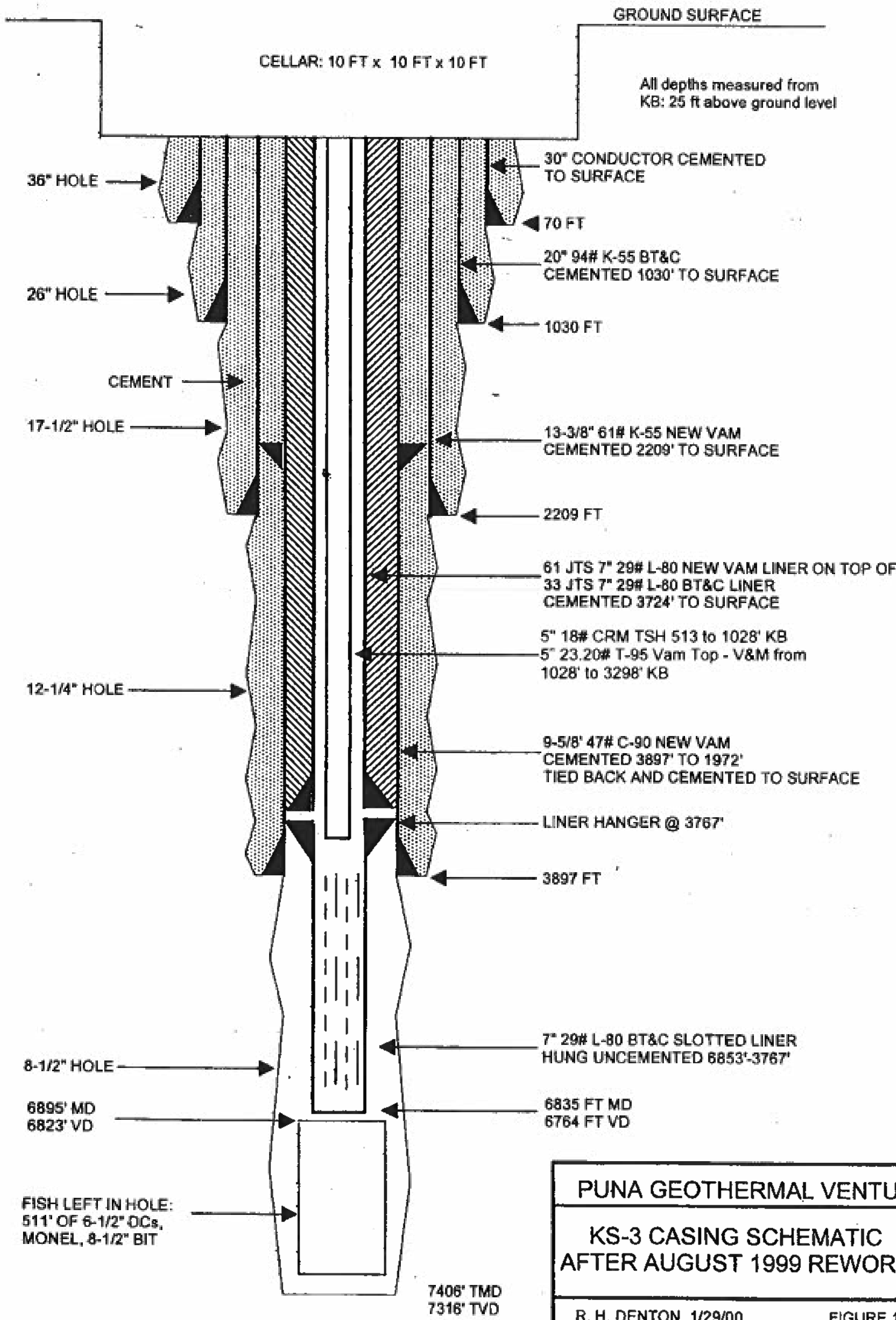
The five injection wells included in this permit application are KS-1A, KS-3, KS-11, KS-13 and KS-15. The schematics for these injection wells are provided on the following figures, respectively. As shown, all five wells have cemented casing set at or deeper than approximately 3,900 feet and are equipped with hang down liners to depths of + or – 3200'. Whenever a well is in service, the annulus between the casing and hangdown liner is pressurized with nitrogen to depress the water level to a depth no less than 2,000 feet below ground surface, which corresponds to the approximate bottom of the underground source of drinking water (USDW). Construction of injection wells KS-17, KS-18, KS-19, KS-20, KS-21, KS-22, KS-23, KS-24, KS-25, KS-26 and KS-27 will be identical in design. This injection well design provides redundant protection of the USDW by virtue of the following features:

- The entire USDW, between the approximate depths of 600 and 2,000 feet, is protected by redundant cemented casing strings;
- Nitrogen pressurization of the annulus allows for immediate recognition of a casing leak that, if otherwise undetected, could result in the loss of injected fluids to the underground aquifer; and
- Nitrogen pressurization of the annulus further protects the USDW from potential contamination by preventing contact of the injectate with the casing in that interval.



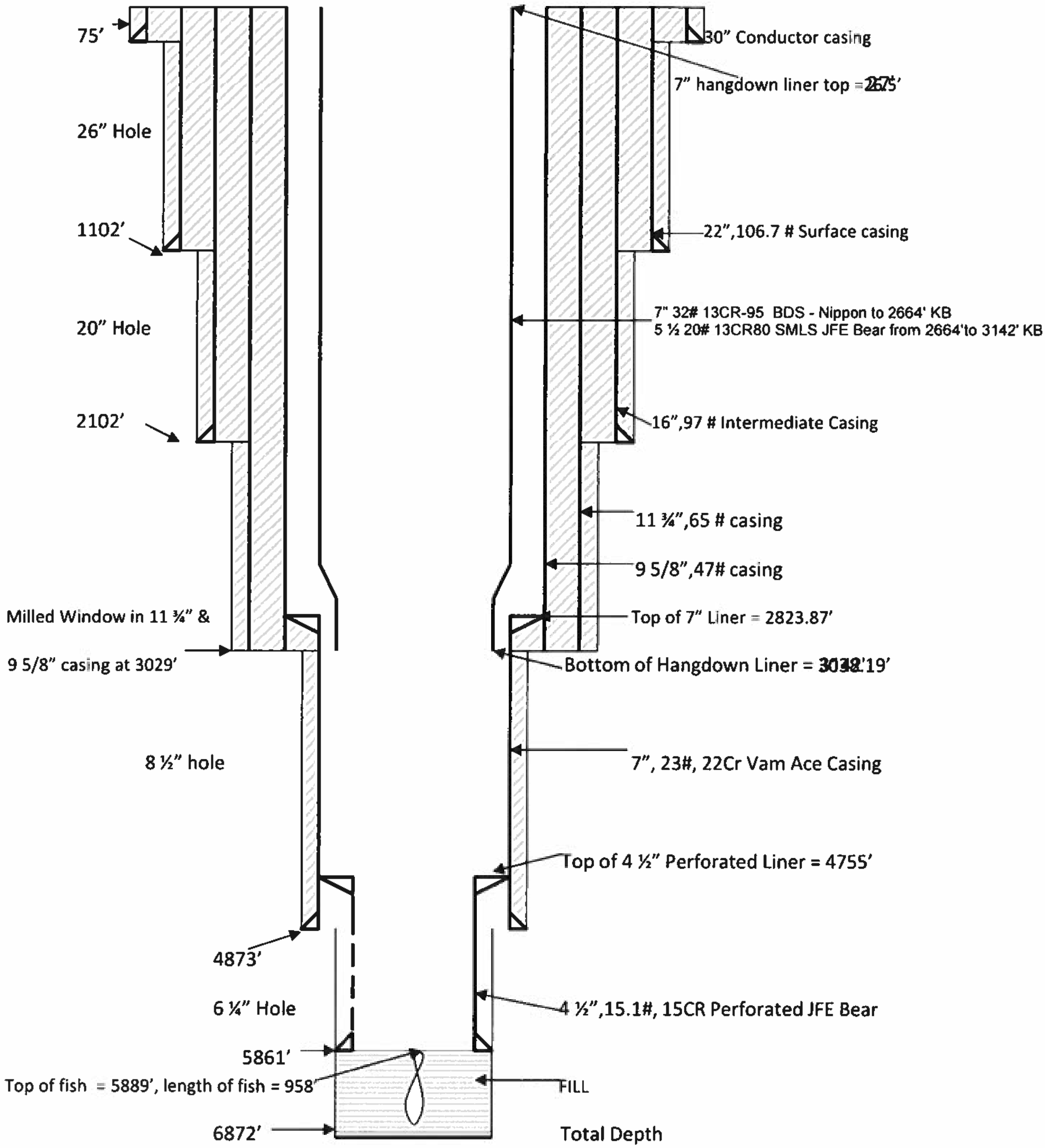
FROM:

PUNA GEOTHERMAL VENTURE
KS-1A CASING SCHEMATIC AFTER 3/22/01 LINER REPLACEMENT
GOLDER ASSOCIATES 4/9/01 FIGURE 1



PUNA GEOTHERMAL VENTURE	
KS-3 CASING SCHEMATIC AFTER AUGUST 1999 REWORK	
R. H. DENTON 1/29/00	FIGURE 1

KS 11 RD2 & RD3 COMPLETION WELL BORE SCHEMATIC as on [illegible]



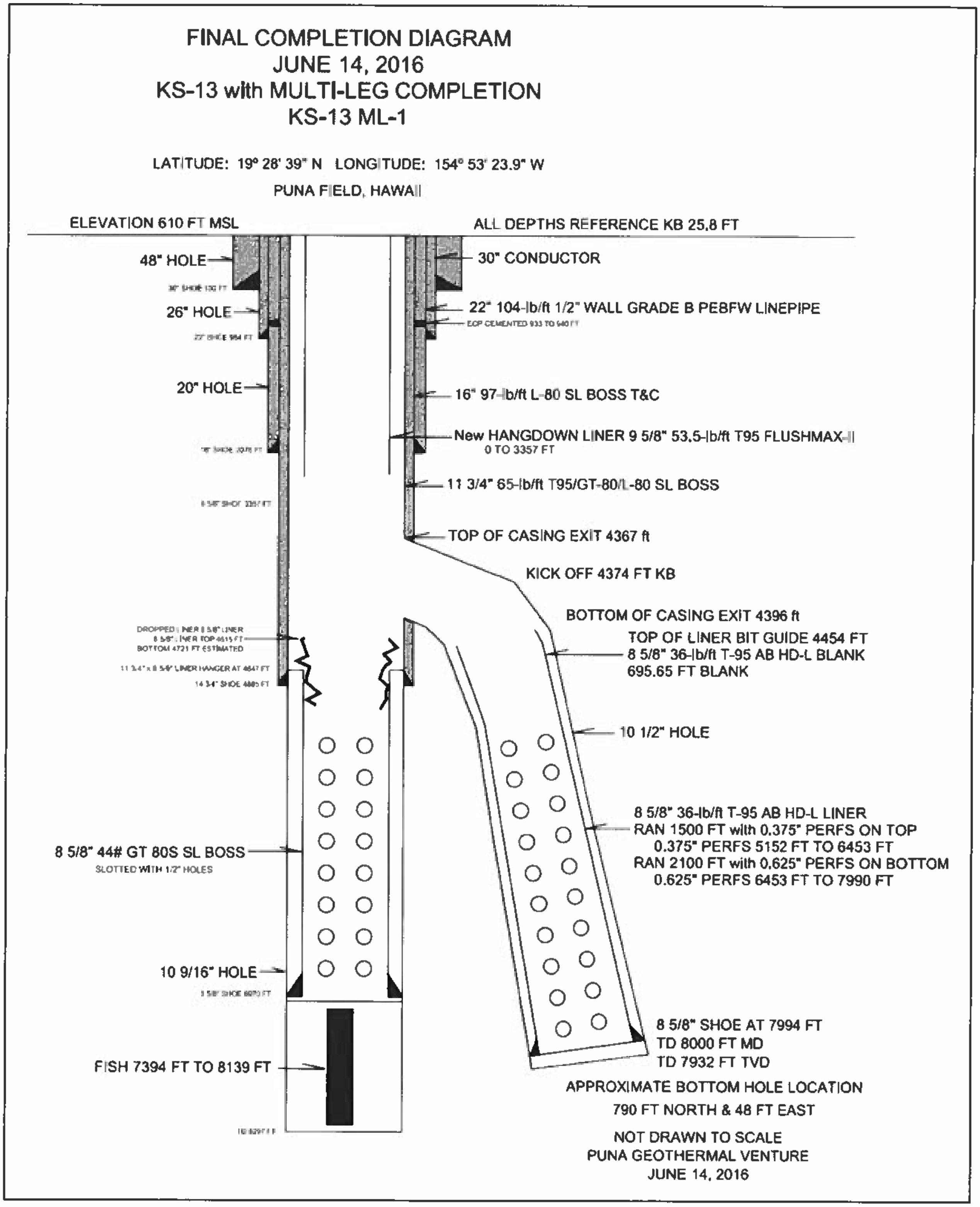


Figure 2. KS-13ML1 wellbore diagram.

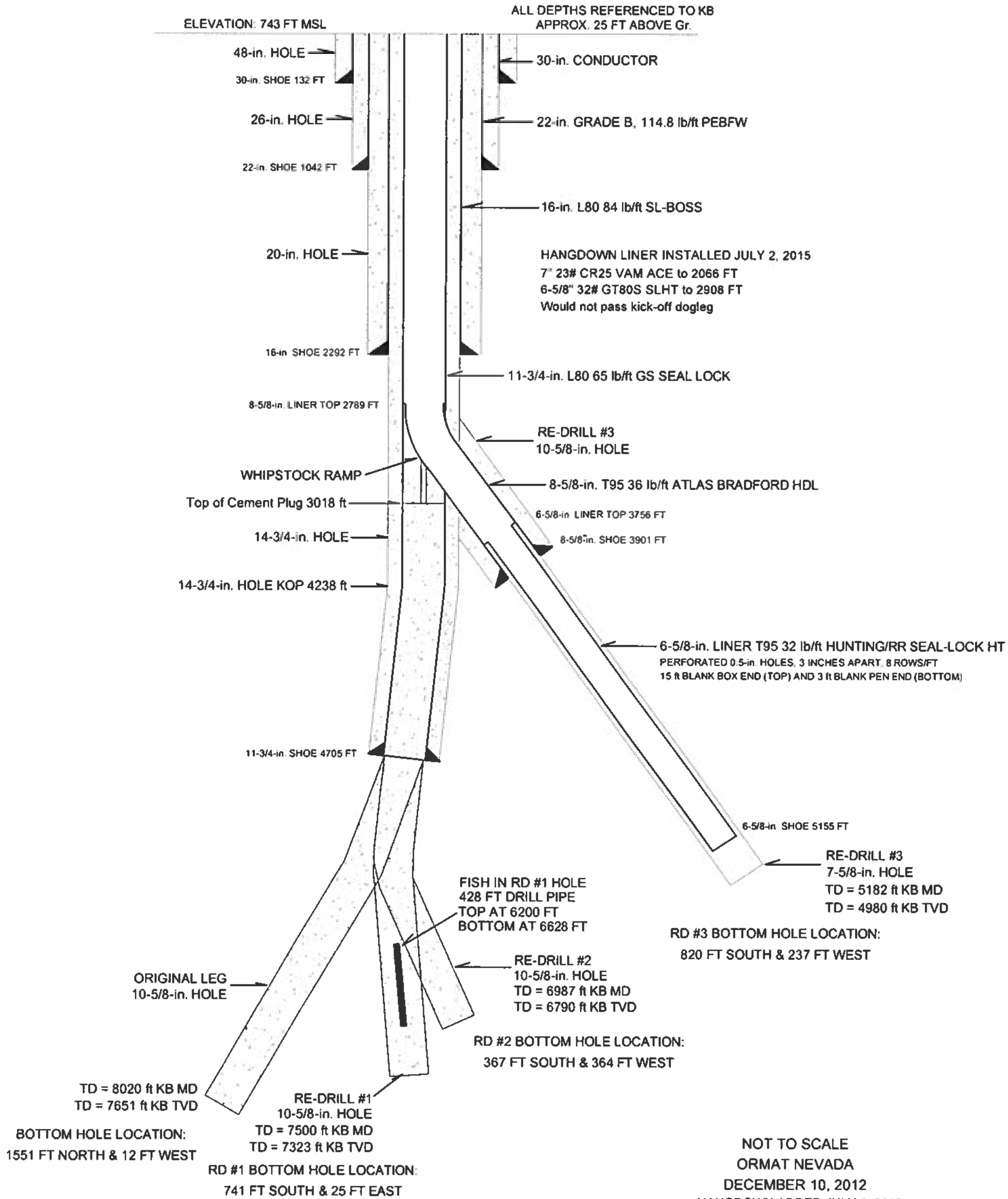
FINAL WELL DIAGRAM
PGV KAPOHO STATE KS-15

Hawaii County, Puna District, HI

Kilauea East Rift Zone

UTM COORDINATES (NAD83): E301953.733 N2154935.556

LAT/LONG: LATITUDE: 19° 28' 45" N LONGITUDE: 154° 28' 45" W



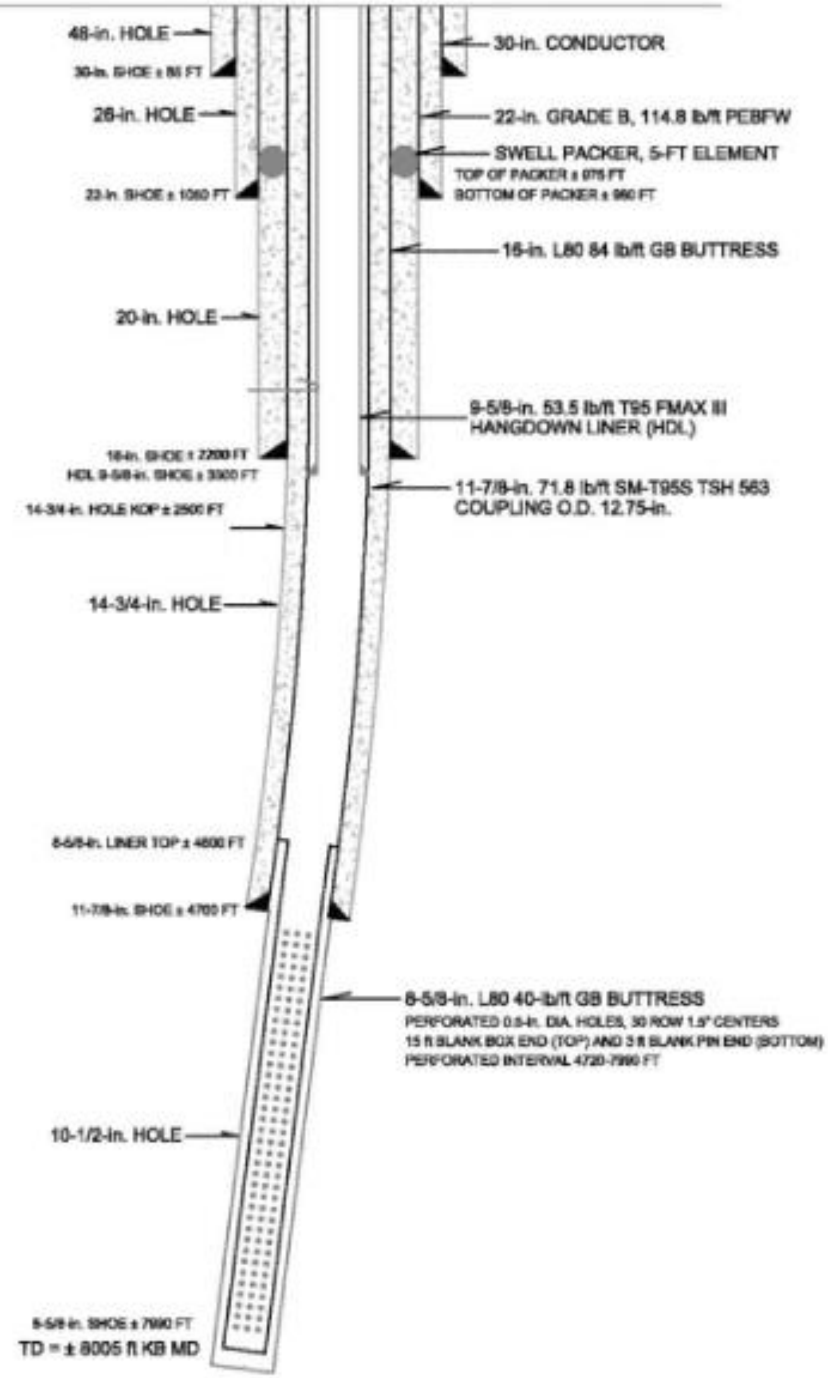
NOT TO SCALE

ORMAT NEVADA

DECEMBER 10, 2012

HANGDOWN ADDED JULY 9, 2015

PUNA GEOTHERMAL VENTURE
STANDARD WELL DIAGRAM-INJECTION WELL



NOT TO SCALE

December 19, 2019

ATTACHMENT M – CONSTRUCTION DETAILS

The five injection wells included in this permit application are KS-1A, KS-3, KS-11, KS-13 and KS-15. The schematics for these injection wells are provided on the following figures, respectively. As shown, all five wells have cemented casing set at or deeper than approximately 3,900 feet and are equipped with hang down liners to depths of + or – 3200'. Whenever a well is in service, the annulus between the casing and hangdown liner is pressurized with nitrogen to depress the water level to a depth no less than 2,000 feet below ground surface, which corresponds to the approximate bottom of the underground source of drinking water (USDW). Construction of injection wells KS-17, KS-18, KS-19, KS-20, KS-21, KS-22, KS-23, KS-24, KS-25, KS-26 and KS-27 will be constructed with a standard design, refer to Attachment M Standard Casing Schematic. This injection well design provides redundant protection of the USDW by virtue of the following features:

- The entire USDW, between the approximate depths of 600 and 2,000 feet, is protected by redundant cemented casing strings;
- Nitrogen pressurization of the annulus allows for immediate recognition of a casing leak that, if otherwise undetected, could result in the loss of injected fluids to the underground aquifer; and
- Nitrogen pressurization of the annulus further protects the USDW from potential contamination by preventing contact of the injectate with the casing in that interval.

ATTACHMENT N

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ATTACHMENT O - PLANS FOR WELL FAILURES

This attachment describes PGV's Contingency Plan to address well failures and prevent the migration of fluids into an underground source of drinking water (USDW).

PGV employs several process control systems that provide effective monitoring of the injection process, and these control systems provide PGV with the ability to quickly and effectively detect and respond to a well failure occurrence. One of these monitoring systems (nitrogen system daily monitoring) is unique in the industry in that it provides the best possible early indication of any well leakage problem. Additionally, redundant control systems and well design are key elements employed by PGV to reduce the potential for impact to a USDW.

Should a well failure occur, the overall PGV injection well system provides for a timely and appropriate response. One key feature of the PGV injection system is the ability to stop the injection of geothermal fluids into any of the injection wells by merely closing the well's valve.

Practically speaking, once a leak in a well system is detected, by means of the daily or other monitoring methods, and is confirmed, the plant operator(s) will respond and manually secure the shut-off valve for the injection well. This immediately stops the flow of fluids into the well. To effectively manage the flow of geothermal fluids from the production well(s), the control operator diverts injectate flow to the other injection wells. In such cases, the plant operation continues by using the excess capacity which is designed into the injection wells. However, if leaks should be detected and confirmed in two injection wells, flow into these two injectors would be stopped and, if necessary, the control operator will reduce the incoming flow from the production well(s).

Additionally, in the unlikely event that all of the injection wells incurred leaks or integrity failures at the same time, these injection wells would be shut in. The production well(s) would be secured or shut in by the control operator utilizing a redundant control system. However, it must be noted that there are also two redundant manual block valves that plant operators may use to shut in a production well. The injection well system also employs this same redundant manual block valve scheme in the injection well area.

In general, the shut-in process can typically be completed by the control operator from the central station control (CSC).

ATTACHMENT P – MONITORING PROGRAM

The existing environmental monitoring program associated with the injection of geothermal fluids at the PGV site consists of monitoring groundwater, injectate, and mechanical integrity. The current groundwater monitoring program is described in the document titled Appendix A, Puna Geothermal Venture Hydrologic Monitoring Program.

PGV's current casing monitoring program is described in Appendix B, Program for Mechanical Integrity Testing and Monitoring of Injection Wells.

Table 1 consists of chemical additives that have been approved by the EPA and HDOH for injection. Tables 2, 3, and 4 are parameters tested for Type I, III, and IV sampling, respectively.

All of the Appendices and Tables in Attachment P are included in the existing State of Hawaii UIC Permit No. UH-1529.

Figure B-1 in Attachment B is a map of the Area of Review showing the location of monitoring wells.

Appendix B

Puna Geothermal Venture

Production and Injection Well Casing Monitoring Program

1. Introduction

1.2 Purpose

The purpose of this CMP is to specify the observations, tests, and drilling operations required to insure that the integrity of production and injection casing remains intact throughout the drilling, testing, and operations of PGV wells. The cemented and hung casing strings that are used in the PGV wells are designed to prevent contamination of shallow aquifers by either reservoir fluid in production wells or power plant effluent in injection wells. Contamination of the shallow aquifers might occur if the casing strings are breached due to corrosion or mechanical failure thus allowing the escape of geothermal brine or injectate to the formation. The casing monitoring program described below is designed to indicate the presence of casing leaks and accurately define their location.

1.3 Scope

This CMP covers all production and injection wells drilled by PGV and all existing wells that were drilled by previous operators on the PGV site which to date have not been plugged and abandoned.

1.4 Hydro geologic Basis for the Casing Monitoring Program

The hydro geologic basis for the CMP is derived from data available from the drilling of wells to depths ranging to 8300' and by three shallow monitoring wells drilled to depths of 640' and 720'. Based on the static temperature profiles, well testing, and behavior of drilling fluid during drilling, it is possible to divide the hydrologic regime it the project area into five major horizontally extensive zones. These zones are reflected in the typical temperature-depth profiles measured in the deep production wells.

1.4.1 The shallowest zone extending from surface to about 6' above sea level is unsaturated and consists of a highly permeable sequence of subareal basalt flows and interflow breccias. Within the project area this zone varies in thickness from 600' to 720' depending on the surface elevation. Numerous cracks with widths of up to 2' traverse the area. These cracks are vertical or very steeply dipping and reach from the surface to at least the top of the warm unconfined aquifer described below. This is evidenced by the discharge of warm, moist air from many of these cracks. The cracks trend parallel to the major structures and lineaments of the Lower East Rift Zone.

1.4.2 The zone below the unsaturated surface rock consists of an unconfined aquifer which contains relatively fresh ground water with varying degrees of natural contamination from the underlying geothermal system. This zone is approximately 1400' thick with the water surface elevation controlled by sea level according to the Ghyben-Herzberg model. The unconfined aquifer surface in the project area is approximately 7' above mean sea level. Based on that model, the thickness of the low salinity lens is therefore about 280'. This constitutes the USDW. The salinity of the underlying water will probably approach that of sea water. The temperature of this zone ranges from 95 to 130 deg. F in the project area and tends to be nearly isothermal throughout the entire interval indication good vertical mixing.

1.4.3 The interval from 1400' below sea level to 2400' below sea level is characterized by an extremely steep thermal gradient in the range of 30 deg. F / 100' or more. The steep temperature gradient is characteristic of conductive heat transfer and indicates the zone has essentially zero vertical permeability. The zone appears to be an effective aquitard separating the high temperature geothermal fluid below from the low temperature unconfined aquifer overlying it. Locally the aquitard exhibits natural leakage as in the area of MW-2 and GTW-III where anomalously high shallow ground water temperatures and salinities are observed.

1.4.4 Between the depth interval 2400' and 4300' below sea level, the temperature profile indicates the existence of a transition zone which consists of alternating permeable and impermeable strata. Within this zone are two more alternating zones of high thermal gradients and isothermal intervals. The high average thermal gradient through this zone indicates that vertical fluid circulation is very limited.

1.4.5 Below a depth of 4300' below sea level, the temperature profile becomes nearly isothermal. This intervals within the geothermal reservoir in which significant vertical movement of fluid is taking place at temperatures above 620 deg. F.

The casing program planned for the production and injection wells calls for cemented casing to reach from ground surface to a depth below 3400' below to 4300' sea level in a competent formation determined by onsite geologists using lithology from collected drilling samples. This allows the casing to be anchored securely within the transition zone described in 1.4.4 and to fully isolate the geothermal reservoir from the shallow aquifer with a cemented interval through the aquitard. Within the shallow aquifer, two cemented casing strings are installed. Three cemented strings pass through the top of the shallow aquifer and the unsaturated zone. The production and injection casing programs are designed to prevent leakage of geothermal fluid from the wellbore into the shallow aquifer above a depth of 1400' below sea level. The CMP discussed below provides the methods and procedures to detect any leakage.

2. Production and injection well casing monitoring program

2.1 Pressure testing during drilling.

Each well is completed with three casing strings cemented to the surface. Immediately upon completion of cementing each string of casing and prior to drilling out the cement shoe, the casing is pressure tested. As required by Title 13 Department of Land and Natural Resources (DLNR) Subtitle 7, Chapter 183, S13-183-76, Well Testing, a test using a combination of density of the fluid in the wellbore and surface pressure of 1/3 of the casing minimal internal yield pressure but not less than 600 psi or as otherwise approved or required by the District Supervisor. After drilling out the shoe, a pressure integrity test below the surface casing or liner and all intermediate casings or liner. You must test to either the formation leak-off pressure or to an equivalent drilling fluid weight if identified in an approved APD. For PGV, the equivalent drilling fluid weight specified in our drilling programs is the 0.65 psi/ft mud pressure gradient. This is designed to stay below the leak-off pressure in order to avoid weakening the formation. PGV uses the terminology "shoe test" or just simply a "Formation Integrity Test" (FIT). A leak off test (LOT) is different than the FIT, as the LOT tests formation until failure, while the FIT tests the formation up to a predetermined pressure before formation failure. The FIT is the preferred term for wells tests in geothermal fields. The FIT procedure is performed after the casing has been cemented and the cement drilled out a few feet below the casing shoe. Pressure is applied to the cement and formation below the casing shoe at a pressure gradient that is below any likely fracture pressure gradient. This assures the integrity of the formation and cement at the shoe. In the case of a leak off the shoe will be squeezed with cement and retested until it passes the FIT. During subsequent operations, injection pressure is limited to the same pressure, which ensure that injectate will not go up behind the casing to shallower depths where the fracture pressure is lower or where protected aquifers might be located. PGV does not establish a specific fracture pressure for the basalt formations, because injection pressures during operations are kept well below fracture pressures. Establishing a fracture pressure gradient is generally not necessary in geothermal areas where the formation fluids are at hydrostatic pressure gradient, over-pressured zones do not exist, and high mud weights are not used.

2.2 Monitoring during injection testing

Upon completion of each well an injection test may be performed to give an initial indication of reservoir permeability. The injection test consists of pumping cool fresh water into the wellbore at several controlled rates while monitoring downhole and wellhead pressure. Pressure temperature logs are also run during the test. These logs can be used to locate leaks in the casing by noting a sudden rise in temperature with depth within the casing string. Also a temperature reversal within the casing string that remains after injection is stopped may be indicative of leakage.

2.2.1 Injectivity testing procedure

- Keep constant pumping rates during the entire test.
- Pump at 1/3 maximum predetermined pump rate with project equipment on site while setting up.
- Run open ended drillpipe into well close to the injection zone and set in pipe rams.
- Rig up slick line unit on drillpipe with a safety valve and lubricator.
- Run sinker bar to maximum reachable depth. Continue pumping at 1/3 max pump rate.
- Run high temperature Kuster PT tool to 10 feet above sinker bar set down depth.
- Pull up to middle of lost circulation zones.
- Wait for 30 minutes.
- Increase pump rate to 2/3 maximum pump rate and pump for 1 hour.
- Increase pump rate to maximum pump rate and pump for 1 hour.
- Stop pumping and wait for 1 hour to record pressure drop off.
- Run PT tool in to 10 feet above sinker bar set down depth, pull PT out of hole at 100 ft/min.

An estimated injectivity index can be calculated into gallons per psi by dividing the maximum flow rate by drop off pressure.

2.3 Monitoring during routine injection

Once annually tests and surveys are conducted on each injection well to verify mechanical integrity of the injection casing and the hangdown liner. Pressure temperature surveys are taken to include a flowing well profile, pressure drop off and static conditions. The resulting pressure and temperature profiles are used to confirm all the injected fluid is exiting at the permitted injection zone with no inter formational flows behind the casing. Yearly surveys are kept on file and cross referenced to previous years to verify if any changing or abnormal conditions arise, indicating a loss of integrity of the casing. All testing is sent to an offsite Hydro geologic Service for review. Upon review a report of each well's condition is generated and submitted to agencies including, DLNR, Hawaii Department of Health, and Federal EPA.

2.4 Monitoring of injection liners

Continuous monitoring is performed by purging the annular space between the injection casing and the hangdown liner. Purge pressure and flow rate will be monitored for any change indicative of a casing leak. Leakage in the casing will cause a drop in annular nitrogen pressure. Pressure on the annular space is kept to a calculated pressure to maintain a fluid level below 2000'. Maintaining calculated pressure to depress the fluid level to 2000' insures that injectate will not leak out of the hang down casing, rather nitrogen will leak into any possibly casing leak. Once annually tests and surveys are also conducted to verify mechanical integrity of the casing and hangdown liner.

2.4.1 An annual pump down test is performed to depress the fluid level to 3000'. Surface pressure on the annulus and hangdown liner are monitored and recorded for 5 hours with initial readings every 10 minutes for the first hour, followed by 30 minute readings for 4 hours. The maximum allowable leak off rate is 10% during the testing period.

2.4.2 An additional test using an Echometer is performed during the pump down test to verify fluid level in the annulas is at 3000'

2.4.3 Logging tools are run into the injection well to the maximum depth or a predetermined depth below 3000'. A pressure temperature survey is taken with the well flowing under normal conditions. The well is then shut in with the PT tool below 3000' to record pressure drop off and an initial static profile. A second PT is completed 12 hours after the well has been shut in to identify fluid levels in the wellbore, a pressure profile and temperature build up. This data will identify any abnormal conditions such as fluid communication outside the casing or unusual thermal recovery after injection is stopped.

2.4.4 Additional testing such as a camera run or a caliper survey to check for integrity can also be completed to obtain further information if more testing is deemed necessary or desired.

ATTACHMENT P-4 - PROPOSED UNDERGROUND INJECTION CONTROL MONITORING PROGRAM

The Puna Geothermal Venture (PGV) geothermal facility injection wells are classified by the United States Environmental Protection Agency (EPA) and the State of Hawaii as Class 5, Subclass E injection wells and thus require an Underground Injection Control (UIC) permit to operate. PGV's UIC Permit No. UH-1529 was originally issued by the State of Hawaii in 1993. EPA Region IX notified PGV in June of 1996 of its intention to issue a federal permit. As part of the application process for the federal permit and modification of the existing state UIC permit, PGV is seeking a revised UIC monitoring strategy.

This attachment describes the proposed monitoring strategy and rationale (Section 1); highlights key prevention and response features of the programs (Section 2); describes the facility's unique "closed loop" process design (Section 3); and summarizes findings and supporting rationale from injectate data collected to date (Section 4). For reference, Appendix P4-A provides an overview of UIC regulatory requirements for monitoring.

1. PROPOSED UIC MONITORING STRATEGY AND RATIONALE

PGV seeks to restructure the UIC monitoring program around the following proven facility systems and programs; thereby eliminating the injectate monitoring previously required.

- Well system design;
- Well system leak monitoring features;
- Pollution prevention activities; and
- Other environmental monitoring programs.

This focus is on "prevention" and response aspects of the facility rather than on monthly or quarterly injectate sampling. It will allow PGV to better focus its resources on efforts to continuously develop, maintain, and improve systems that <u>prevent</u> potential environmental impacts, rather than on simply <u>characterizing</u> potential impacts after the fact. This approach meets the principal environmental and regulatory goal of the State and Federal UIC programs to "protect potential underground sources of drinking water" (USDW) in the project area.

PGV's rationale for eliminating future injectate sampling is based on the existence and proven performance of the facility's state-of-the-art well design and leak monitoring systems, pollution prevention activities, and other environmental monitoring programs. In addition to these in-place prevention and monitoring systems, the PGV geothermal facility uses essentially a "closed loop" process whereby fluids injected into the geothermal reservoir are composed almost entirely of the same naturally occurring fluids removed from the reservoir. Each of these monitoring components is described in Section 2.

2. KEY RESPONSE AND PREVENTION FEATURES OF PROPOSED MONITORING PROGRAM

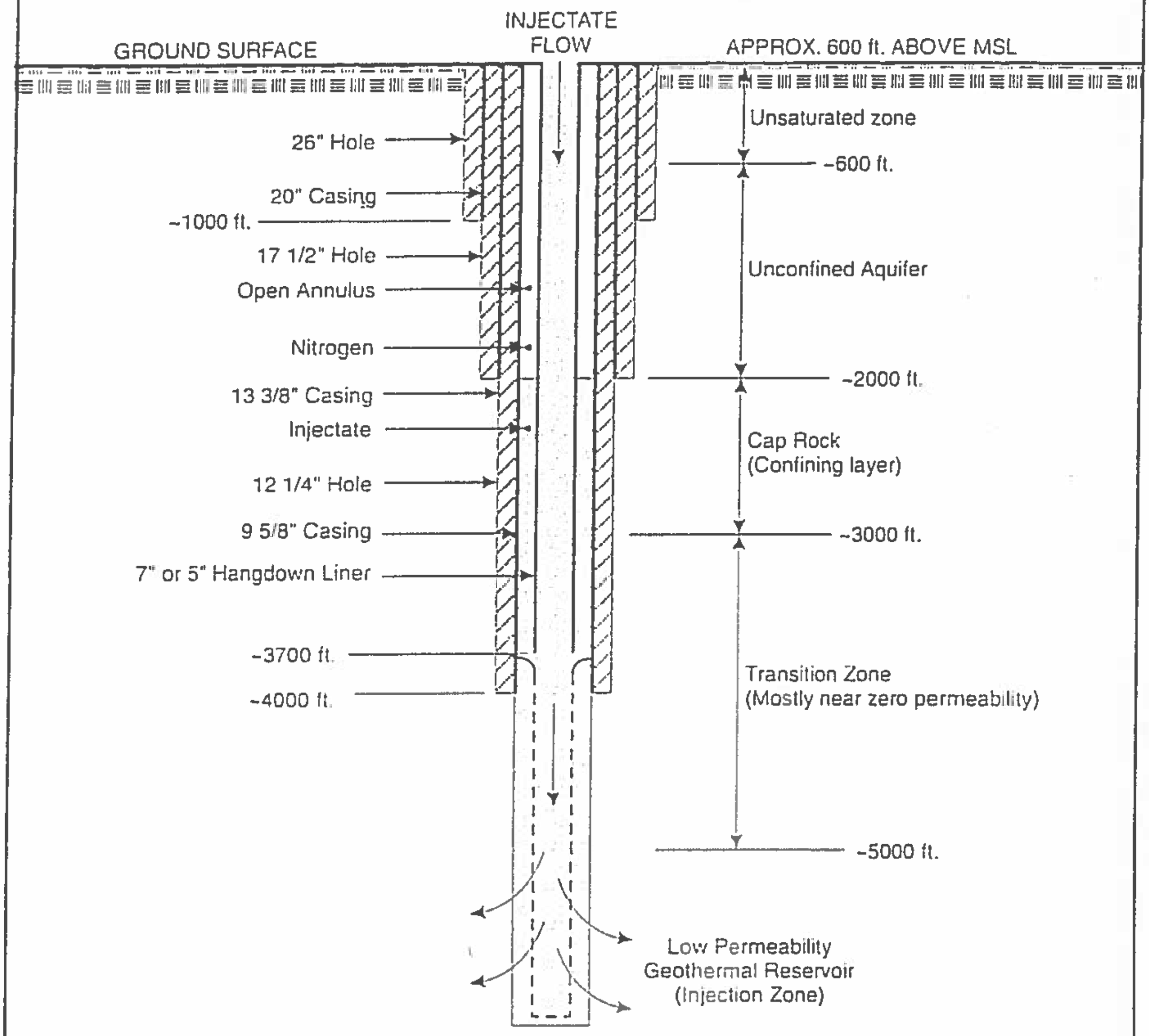
2.1 Well Design

Proper design of the injection wells is essential to prevent potential impacts to USDWs. PGV's wells are designed with redundant protection features. Specifically, each well (production and injection) is typically completed with three casing strings cemented to the surface (Figure P4-1). The first casing string (20-inch) typically extends to a depth of approximately 1,000 ft, which spans the upper portion of the groundwater aquifer. The second casing string (13 3/8-inch) is cemented to approximately 2,000 ft, essentially the bottom of the groundwater aquifer. The third casing string (9 5/8-inch) extends to approximately 4,000 ft. This design provides for redundant protection against leakage into the USDW zone by no less than two casing strings (13 3/8-inch and 9 5/8-inch). This represents the best design practice in the industry.

In addition to the cemented casing strings shown in Figure P4-1 and discussed above, each of PGV's injection wells is equipped with a free-hanging string of pipe, called a hangdown liner, through which the injectate flows. The hangdown liner is suspended from the wellhead to a depth of approximately 3,500 ft, or deeper, and serves the purpose of isolating the injectate from the inner permanent (cemented) casing to a depth well below the confining layer.

2.2 Injection Well System Monitoring

The annulus of each injection well (i.e., the space between the hangdown liner and the inner cemented casing) is pressurized with nitrogen. Nitrogen pressurization of the annulus serves the dual function of allowing continuous monitoring for casing leaks and protecting the potential USDWs from contamination if a leak were to occur. Nitrogen is added as needed to maintain the water level in the annulus at a depth equal to or greater than the bottom of the USDW. The nitrogen pressure is recorded continuously and monitored daily by plant operators for any unusual drop in pressure, which



SCALE: 1" = 1000 ft.

Figure P4-1

D-1

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Title
PUNA GEOTHERMAL VENTURE

Figure
INJECTION WELL DESIGN AND GENERAL HYDROGEOLOGIC CROSS-SECTION IN THE VICINITY OF PGV's INJECTION WELLS

Drawn By	Date	TDD/Job No.	Dwg. No.
MRE	7-17-95		XM1234

could be indicative of a casing leak. If such a problem is detected, procedures are implemented immediately to confirm the observation and, if a there is a loss of mechanical integrity, to shut-in the well and stop the leakage of injectate.

This leak monitoring feature is unique in the industry. Other systems more common to the geothermal industry rely on annual casing testing. While this has been determined to be acceptable, the PGV system exceeds this with real time leak detection capability. It provides the best possible early indication of any leakage problem and allows for immediate response. This monitoring system is far better as a "pollution prevention feature" than after-the-fact monitoring in the form of injectate sampling.

In addition to the daily leak monitoring feature, an annual casing pressure test and a series of downhole temperature surveys are performed to further confirm the mechanical integrity of each injection well. If a well fails to meet criteria specified in the Program for Mechanical Integrity Testing and Monitoring of Injection Wells (see Attachment P-2), action is immediately taken to confirm the findings, shut-in the well, and repair the leak.

This annual program provides the added benefit of confirming the external mechanical integrity of the wells. Failures of external mechanical integrity, i.e., interzonal flow of fluid outside of the casing to a USDW, are extremely rare in geothermal injection wells, but the annual test is done to assure complete mechanical integrity exists.

2.3 Process Control Systems

PGV employs several process control systems that provide effective monitoring of the injection process to ensure a controlled response if an upset condition should occur. Typically these control and response systems are designed to be redundant, which greatly reduces the potential for response failure when it is needed.

One key feature of the PGV injection system is the ability to stop the injection of fluids into any one of the injection wells if a well failure should occur. This can be accomplished in the following manner. Once a well system leak is detected by means of the daily or other monitoring methods and is confirmed, a plant operator manually secures the injection well to immediately stop the flow of any fluids into that well. This essentially eliminates the potential for an impact to the USDW. To effectively manage the flow of geothermal fluids from the production wells, the control operator diverts the incoming flow to the other injection wells. In such cases, plant operations continue using the excess capacity available from the other injection wells. However, if leaks should be detected and confirmed in two wells, flow into those injectors would be stopped and the control operator may have to reduce the incoming flow from the production wells. Additionally, in the unlikely event that all of the injection wells incurred leaks or integrity failures at the same time, these injection wells would be shut in. The production well incoming geothermal fluids would be stopped utilizing a redundant control system. This system allows plant and control operators to curtail the incoming flow of geothermal steam and fluids from the production wells and the facility becomes secured or shut down.

Another feature includes the injectate pressure and flow monitoring instrumentation. This instrumentation allows control operators to continuously track the injectate pressure and flow from the control room. This allows them to take immediate action to reduce pressure to stay within the required wellhead limit and prevent a negative impact on the mechanical integrity of the wells.

PUNA GEOTHERMAL VENTURE

HYDROLOGIC MONITORING PROGRAM

December 2005

Sampling Locations: The following wells will be monitored.

Well Name	Elevation (MSL)	Completion Depth (MSL)
MW-1	610	-46
MW-2	588	-2
MW-3 (standby)		

Frequency: Regular sampling shall occur twice a year, once in January and once in July.

Water Level Measurements: Prior to bailing or pumping the well and sampling, water level measurements will be taken and recorded. The permittee can use an Echo Meter or similar device, or an electronic direct contact detection probe with a calibrated cable/tape for direct measurement at the top of the well casing. Calibrated cable/tape length shall be sufficient to measure water levels in the deepest wells. The metering device shall be equipped with an audible signal and light to indicate water level contact.

Quality Assurance/Quality Control: Quality assurance/quality control procedures will be in compliance with standards of practice for similar programs relative to the acquisition, reduction, verification, and validation of the site data. At each location, standardized equipment cleaning will be conducted prior to obtaining each sample.

Prior to ground water sampling, the well will be bailed or pumped at least three times the wellbore volume.

All samples will be taken and field analyses conducted in accordance with standard protocols approved by the EPA. An EPA or State of Hawaii certified laboratory will be used to conduct the analyses for samples submitted. Samples will be transferred from the sampling device directly to appropriately prepared containers supplied by the laboratory. Samples will be labeled, stored and transported in a chilled state in insulated containers to the laboratory.

In the analyses, detection limits will be used that are below maximum contaminant levels. If they are not, the sampling and analyses will be repeated using the proper detection limits.

The contractor will provide a copy of their Quality Assurance program to DOH and EPA for review and approval.

Physical and Chemical Parameters: Field analyses will include:

- pH
- temperature
- conductivity
- salinity
- chloride concentration
- water level

These measurements will be obtained by using calibrated instruments specifically designed to

directly measure these physical and chemical parameters within the operational constraints dictated by site conditions.

The inorganic (Type I) and organic (Type II and IV) constituents that are to be sampled for are specified in Appendix H.

Reporting: Sampling results and measurements will be submitted during the February following the January sampling, and the August following the July sampling. Original laboratory reports will be included with a cover letter. Reporting units shall be specified. The laboratory shall not use text descriptions, such as "Below Regulatory Limits" or "BRL", in its reporting, but rather, the actual numerical results will be reported. If the actual numerical results are not reported, the sampling and analysis will be redone until numerical results are reported.

Further Monitoring: If leakage of the injectate into the USDW is suspected, the ground water sampling may be modified. Depending on the situation, this could include sampling from Malama Ki and GTW-III, sampling for certain analytes and more frequent sampling.

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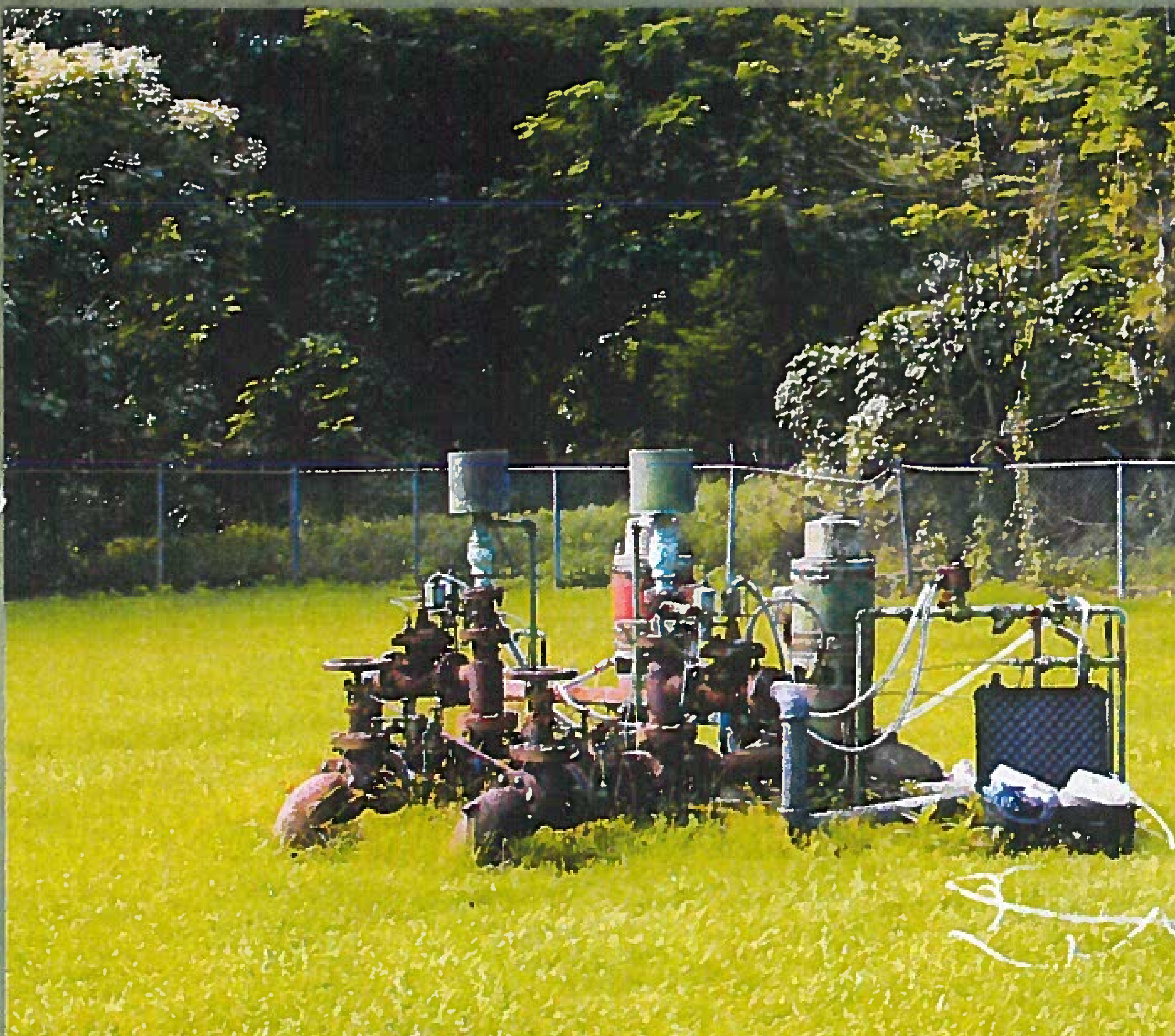
Groundwater Chemistry in the Vicinity of the Puna Geothermal Venture Power Plant, Hawai'i, After Two Decades of Production



Scientific Investigations Report 2015–5139

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COVER
Groundwater pumps at the Kapoho Shaft, Puna District, Hawai'i. Photograph by Deborah Bergfeld, U.S. Geological Survey

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U.S. Geological Survey, Reston, Virginia: 2015

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Conversion Factors

International System of Units to Inch/Pound

Multiply	By	To obtain
	Length	
meter (m)	3.281	foot (ft)
kilometer (km)	0.6214	mile (mi)
	Volume	
liter (L)	0.2642	gallon (gal)
	Flow rate	
meter per day (m/d)	3.281	foot per day (ft/d)
	Mass	
gram (g)	0.03527	ounce, avoirdupois (oz)
kilogram (kg)	2.205	pound, avoirdupois (lb)

Temperature in degrees Celsius (°C) may be converted to degrees Fahrenheit (°F) as °F = (1.8 × °C) + 32

Temperature in degrees Fahrenheit (°F) may be converted to degrees Celsius (°C) as °C = (°F - 32) / 1.8

Datum

- Vertical coordinate information is referenced to the North American Vertical Datum of 1983 (NAD83).
- Horizontal coordinate information is referenced to the North American Vertical Datum of 1983 (NAD83).
- Altitude, as used in this report, refers to distance above the vertical datum.

Supplemental Information

- Specific conductance is given in microsiemens per centimeter at 25 degrees Celsius (µS/cm at 25 °C).
- Concentrations of chemical constituents in water are given in either milligrams per liter (mg/L), micrograms per liter (µg/L), or micromoles per kilogram (µmol/kg), where a kilogram of water is nearly equal to a liter.
- Concentrations of chemical constituents in gas are given in either volume percent or in parts-per-million by volume.
- Results for measurements of stable isotopes of water are expressed as the relative difference in parts per thousand (per mil) in the ratio of the number of the less abundant isotope (D or ^{18}O) to the number of the more abundant isotope (H or ^{16}O) with respect to Vienna Standard Mean Ocean Water (VSMOW).

Acknowledgments

Jim Kauahikaua (former U.S. Geological Survey [USGS] Scientist-In-Charge of the Hawaiian Volcano Observatory) encouraged us to undertake this study. Jeff Melrose (consultant for the County of Hawai'i) was influential in moving the study forward and in arranging logistics. Kawika Uyehara and Keith Okamoto (County Department of Water Supply [DWS]) helped arrange sample collection at public-supply wells, including the Kapoho Shaft, and provided the DWS records of water chemistry. Mark Prescott and Sam Martoni arranged sample collection at the private wells. Mike Kaleikini (Ormat) provided helpful information about the Puna Geothermal Venture plant, fluid flowpaths, additives used, and spreadsheets of monitoring data, and also arranged for our sample collection at the plant, which relied heavily on assistance from Gary Dahl (Ormat). Bob Whittier (Hawai'i State Department of Health [HDOH], Safe Drinking Water Branch) provided a huge amount of background information on past and present monitoring programs; Norris Uehara and staff in that office patiently scanned hundreds of HDOH analytical records and sent them as pdf files. Don Thomas (University of Hawai'i) and Thomas Travis provided helpful feedback on the study objectives, as did Steve Gingerich and Jennifer Lewicki (USGS). Mark Huebner (USGS) transcribed hard-copy data into electronic spreadsheets and conducted the anion analyses. Steve Ingebritsen (USGS) and Don Thomas (University of Hawai'i) provided helpful reviews of the draft report.

Groundwater Chemistry in the Vicinity of the Puna Geothermal Venture Power Plant, Hawai'i, After Two Decades of Production

By W.C. Evans, D. Bergfeld, A.J. Sutton, R.C. Lee, and T.D. Lorenson

Abstract

We report chemical data for selected shallow wells and coastal springs that were sampled in 2014 to determine whether geothermal power production in the Puna area over the past two decades has affected the characteristics of regional groundwater. The samples were analyzed for major and minor chemical species, trace metals of environmental concern, stable isotopes of water, and two organic compounds (pentane and isopropanol) that are injected into the deep geothermal reservoir at the power plant. Isopropanol was not detected in any of the groundwaters; confirmed detection of pentane was restricted to one monitoring well near the power plant at a low concentration not indicative of source. Thus, neither organic compound linked geothermal operations to groundwater contamination, though chemical stability and transport velocity questions exist for both tracers. Based on our chemical analysis of geothermal fluid at the power plant and on many similar results from commercially analyzed samples, we could not show that geothermal constituents in the groundwaters we sampled came from the commercially developed reservoir. Our data are consistent with a long-held view that heat moves by conduction from the geothermal reservoir into shallow groundwaters through a zone of low permeability rock that blocks passage of geothermal water. The data do not rule out all impacts of geothermal production on groundwater. Removal of heat during production, for example, may be responsible for minor changes that have occurred in some groundwater over time, such as the decline in temperature of one monitoring well near the power plant. Such indirect impacts are much harder to assess, but point out the need for an ongoing groundwater monitoring program that should include the coastal springs down-gradient from the power plant.

Introduction

The lower East Rift Zone (LERZ) of Kīlauea volcano on the island of Hawai'i (fig. 1) hosts a geothermal reservoir at depths near 2 km, and the hot fluids have been exploited for power generation since 1981 (Thomas, 1990). An early and on-going concern about geothermal development is the potential impact on local groundwater (for example, Iovenitti, 1990). To address this concern, a major scientific effort was carried out in the early days of well drilling and development to characterize existing hydrologic conditions in the region and delineate potential vulnerabilities (Iovenitti, 1990; Ingebritsen and Scholl, 1993; Sorey and Colvard, 1994; Janik and others, 1994; Gingerich, 1995; Scholl and others, 1995). The basaltic lava flows from Kīlauea and its rift zone vents provide highly permeable flow paths for groundwater, but vertical dikes within the upper rift zone constitute effective barriers. Thus, groundwater north of the rift zone flows northeast toward the ocean. Groundwater within the rift zone flows generally down rift toward Cape Kumukahi, but some outflow into the permeable lava flows to the south is suspected along the lower part of the rift where the concentration of impermeable dikes decreases (Takasaki, 1993; Gingerich, 1995). Several shallow groundwater wells in the LERZ are tens of degrees warmer than ambient temperatures, and brackish springs along the southeast coast of the island, down the hydraulic gradient from the LERZ, are several degrees warmer than background. Thus, some type of hydrologic connection between the geothermal and groundwater systems is indicated. On the other hand, the warm groundwaters lack some of the distinctive features in the chemical composition of the deep geothermal water. This fact and other information from drill cores and temperature profiles in deep wells led many investigators to conclude that direct leakage of water from the geothermal reservoir into groundwater was insignificant (Janik and others, 1994; Sorey and Colvard, 1994). The warm temperatures in groundwater wells and coastal springs were commonly attributed to conductive heat transfer. Although some direct leakage of reservoir steam and sulfur-rich gas was proposed to account for the elevated temperatures and sulfate concentrations in shallow monitoring wells in the LERZ (Janik and others, 1994; Sorey and Colvard, 1994), a discharge pathway for hot water from the reservoir was not identified.

The large-scale scientific investigations of the hydrogeology and groundwater chemistry at Kīlauea and the

LERZ in the early 1990s established the baseline geochemical conditions at about the time that Puna Geothermal Venture (PGV) began producing power from new wells in place of the original HGP-A well that had been used throughout most of the 1980s. A follow-up monitoring program was recommended (Sorey and Colvard, 1994) for detection of any impacts from producing the hot reservoir fluids or from injecting the cooled water back into the deep reservoir. As a condition of the underground injection control permit (UH-1529), PGV must conduct a hydrologic monitoring program. Under this program, several shallow wells, thermal and nonthermal, were sampled quarterly for chemical analysis, and the results reported to the State of Hawai'i Department of Health (HDOH) from 1991 through 2000. Beginning in 2001, the number of wells sampled each round by PGV was reduced to two thermal wells near the power plant, MW-2 and either MW-1 or MW-3, which are adjacent wells that tap similar depths. The County of Hawai'i Department of Water Supply (DWS) routinely monitors nonthermal wells that are used for public supply. Coastal springs have gone largely unmonitored, and thus the full, cumulative impact of over 20 years of geothermal production/injection on this large groundwater system is unknown. These springs, sometimes referred to as anchialine pools, are brackish and unsuitable for drinking or agricultural use, but are recognized as important habitats in the near-shore environment (Foote, 2005). Recently (September 2013), a local public health assessment study group headed by Dr. Peter S. Adler recommended that the County commission a study to re-evaluate the effects of geothermal operations on local groundwater and the near-ocean environment (Adler, 2013). Our study was proposed in response to a County of Hawai'i request.

The work was planned to be a pilot study of fairly limited scope: collect enough samples to obtain representative coverage of the various types of groundwater (for example, deep geothermal water, warm saline spring water, public-supply water) rather than attempt to sample every available feature. The results could then be used to help determine the need for a bigger, more comprehensive study. None of the water-supply wells currently in use are obviously down-gradient from the PGV plant, but some have static water levels at lower elevations than those reported for the geothermal wells. Thus, sample coverage extended nearly 10 km away from PGV to help detect any impact of development. Some of the intended target wells down-gradient from PGV were found unsuitable for sampling because of access issues or nonfunctional pumps. Thus more emphasis was placed on sampling the coastal springs to characterize ground-water most likely to be impacted by geothermal operations.

Sites sampled in April–May 2014 included a pair of public supply wells on either side of the LERZ, three private water-supply wells north of the LERZ, six coastal springs

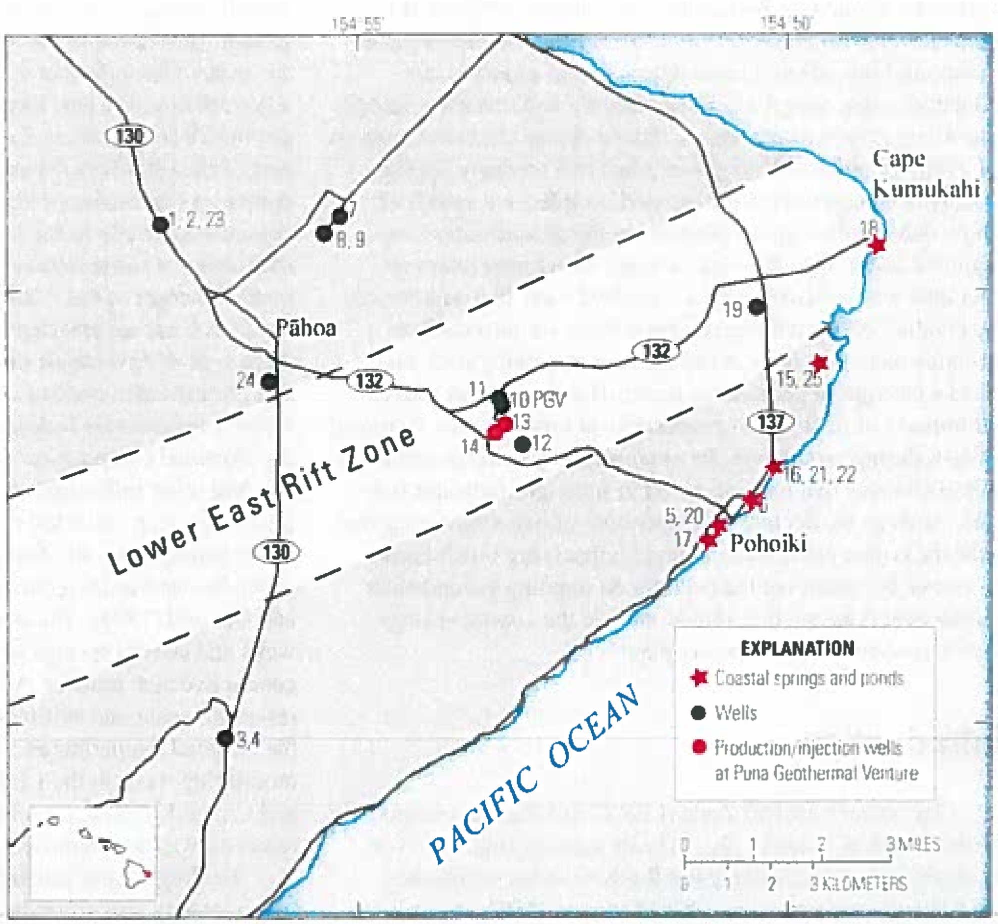

Figure 1. Map of study area showing sample locations and features of interest. Sample numbers simplified from table 1 (for example, PG14-01 is 1). Coastal springs and ponds are shown as stars, and wells are shown as circles (in red for the production/injection wells at Puna Geothermal Venture). The lower East Rift Zone (LERZ) of Kīlauea volcano lies between the dashed lines (after Janik and others, 1994).

and pools, and the three warm monitoring wells near the power plant. The steam and residual brine from a geothermal production well (KS-5), and the combined injectate stream (at Pad A) were also sampled. Additional samples were collected in December 2014 from two public supply wells (one unused) within or adjacent to the LERZ, and four coastal springs, two of which had been sampled previously in April–May 2014. One of the public supply wells north of the LERZ was also resampled. The water samples were analyzed for a suite of inorganic constituents including several heavy metals, but a unique feature of our study was the high sensitivity analysis of pentane and isopropanol. These two organic compounds are added to the injectate stream within the power plant and could serve as definitive tracers of the geothermal fluid. Although degradation of natural organic matter in any aquifer can release a wide range of organic compounds into groundwater, especially at elevated temperatures, neither pentane nor isopropanol should be present at more than trace levels in groundwaters that are uncontaminated by PGV injectate. Current groundwater monitoring protocol does not include analysis of these compounds.

This report presents chemical analyses of the samples discussed above. Selected chemical data gathered during the past ~20 years of monitoring conducted or overseen by the HDOH and DWS are also presented, and the combined dataset is evaluated to assess the likelihood that geothermal development is affecting the regional groundwater.

Geothermal Development and Operations

Exploratory drilling in the 1960s established the existence of hot water within the LERZ to the south and east of the community of Pāhoa (Thomas, 1987). The first productive well (HGP-A) was completed in 1976 to a depth of nearly 2 km. After a series of tests, this well was used for power production beginning in 1981 and ending in 1989 (Thomas, 1987, 1990). During the 1980s and early 1990s, PGV or its predecessor companies drilled the nearby Kapoho State wells (KS series), some reaching depths in excess of 2.5 km, and began producing power in May 1993 (Sorey and Colvard, 1994). The PGV plant has been in operation since that time and has continued well drilling operations; for example, KS-13 in 2005 (Teplow and others, 2009).

Unlike the HGP-A installation, the PGV plant does not use infiltration ponds for liquids or engineered abatement for the produced gases under normal conditions, though abatement of H_2S is carried out during emergencies that cause steam release to the atmosphere. The plant does incorporate a steam flash process where steam and gases separate from the residual boiled water (brine). The high-pressure steam drives a turbine in the generating system, but condensation of the steam takes place downstream in a heat exchanger where the heat is used to boil liquid pentane. The condensed steam, and ultimately the noncondensable gases such as CO_2, H_2, N_2, and H_2S, are mixed back into the brine flow, and the recombined fluid is injected in its entirety back into the deep geothermal reservoir. The pentane vapor from the heat exchanger drives an additional turbine, is condensed back to liquid, and is ultimately returned to the heat exchanger. Thus, according to plant design, no geothermal gases or fluids are intentionally released to the environment, and the pentane circulates through the plant in a closed loop that is separate from the water and steam. In practice, a small amount of pentane does enter the flow stream and is injected into the reservoir.

Because steam and gas separate from the residual brine upstream from the sampling ports, both the steam and brine pipelines were sampled in order to completely characterize the reservoir fluid tapped by the plant. Our sample from the injectate pipeline was collected downstream from the point where steam, gas, and brine are recombined and just prior to the point of injection back into the reservoir. The injectate sample is particularly important to this study because it contains all the gases and dissolved species that are present in the produced reservoir fluid. It would also contain any additives (for example, isopropanol) and other compounds derived from plant operations that enter the flow system. Geothermal water that enters the local groundwater system, either through permeable flowpaths out of the reservoir or through leaks in the well casings, would most likely resemble the injectate in terms of chemistry. Distinguishing the composition of the injectate from that of other thermal fluid(s) long known to be present in the warm groundwaters and coastal springs is an important part of evaluating connectivity between the developed geothermal system and groundwater, a key step in assessing impact.

Methods

The location of each sampled feature was determined to within a few meters with a hand-held global positioning system (GPS). Water temperature, specific conductance, pH, and dissolved oxygen (DO) were measured on-site using hand-held meters. At springs, the measurements were made near the water surface. For wells, a continuous flow of pumped water from the wellhead was directed into a plastic container housing the measuring probes. In all cases, the pH meter was calibrated with buffer solutions at the temperature of the water.

Water samples were collected using standard methods that have been described in detail elsewhere (Bergfeld and others, 2013). Briefly, water collected for chemical analysis was filtered on-site into plastic bottles using a plastic syringe and 0.45-micrometer (µm) filters. The bottle for cation analysis was acidified to pH 2 with nitric acid. Glass bottles were filled with unfiltered water for alkalinity determinations, and analysis of stable isotopes of hydrogen and oxygen. Water was collected for pentane analysis by two different methods. In one method, water was drawn up into a 140-cubic centimeter (cc) syringe and injected into a pre-evacuated glass bottle (DIC bottle) through a septum port, leaving a headspace volume of about 15–25 cc in the bottle. A description of these bottles is provided in Evans and others (2002). The second method made use of 200-cc serum bottles, which were filled from the bottom by flowing in water through flexible tubing. After allowing 600 cc of water to overflow and flush the bottle, the tubing was slowly withdrawn and a rubber septum was inserted into the top of the bottle and crimped in place with a metal band. Samples for isopropanol analysis were collected in triplicate into 40-cc amber glass bottles fitted with screw-on septa caps. Bottles were filled to exclude any bubbles as described in Wilde and others (2004). Isopropanol samples were refrigerated or stored on ice between collection and analysis.

Sampling of geothermal fluids from the pipelines requires precooling to prevent extensive loss of steam and gas as the hot fluids are depressurized. Cooling was accomplished at the PGV plant by collecting the samples through a cooling jacket flushed by a steady stream of cold water, that resulted in collection temperatures of about 30 °C. Gas solubility increases as temperature decreases, and for sampling the brine pipeline, this level of cooling was sufficient to produce a flow of bubble-free water at the collection point. Bubble-free water was initially obtained from the injectate pipeline but could not be maintained throughout sampling due to the added gases in the injectate. The small bubbles that formed in the sampling line were captured into an inverted funnel and collected in a pre-evacuated glass bulb. As anticipated, the steam line was so gas rich that the water flow contained a steady stream of bubbles that were also collected into a glass bulb. Two other special sampling procedures (Presser and Barnes, 1974) were used on the geothermal fluids: water filtered into glass bottles was preserved for H_2S analysis with zinc acetate and sodium hydroxide, and aliquots of the brine and injectate were field-diluted with deionized water to prevent polymerization of silica prior to analysis.

Samples collected for alkalinity and H_2S were titrated at the end of each sampling day. Standardized solutions of H_2SO_4 (for alkalinity) and $Na_2S_2O_3$ (for total sulfide) were used following the electrometric and iodometric procedures, respectively, described in Presser and Barnes (1974). Other water samples and gases were analyzed at several U.S. Geological Survey (USGS) laboratories. Chemical analyses were conducted at USGS in Menlo Park, Calif. Gas samples from the PGV plant were analyzed on gas chromatographs in two different USGS labs following published methods for free gases (Evans and others, 1981) and headspace gases (Bergfeld and others, 2011). One gas chromatograph was equipped with a thermal conductivity detector (TCD) responsive to all gas species; the other had an additional flame ionization detector (FID), highly sensitive but only responsive to flammable gas species, in this case, hydrocarbons. Water samples were analyzed for anions by ion chromatography and for cations by argon plasma optical emission spectrometry. Stable isotope analyses of the waters were performed by mass spectrometry at the USGS Reston Stable Isotope Laboratory (Revesz and Coplen, 2008a,b). Isopropanol analyses were conducted at the USGS National Water Quality Laboratory in Denver Colo. using a volatile organic compound (VOC) heated purge and trap method on Schedule 4437 that detects 37 other VOCs. The VOC analysis was performed on samples from PG14-01 to PG14-19 and PG14-24.

Dissolved pentane samples were also analyzed at two different USGS labs in Menlo Park, Calif. Pentane samples collected in DIC tubes were analyzed on a gas chromatograph equipped with both a TCD and a FID using a slight modification of the headspace gas method of Bergfeld and others (2011). This method yields results for a large suite of nonhydrocarbon and hydrocarbon gas species, including pentane. The gas in the equilibrated headspace was expanded to a pre-evacuated inlet system and injected into the gas chromatograph. From the known volumes of the headspace and inlet system, and the measured injection pressure, the concentrations of the gases that were originally dissolved in the water sample can be calculated from their individual Henry law solubilities (Wilhelm and others, 1977; Chapoy and others, 2008). Samples collected in serum bottles were analyzed by equilibrating 100 cc of water with 40 cc of helium and injecting the equilibrated gas into a gas chromatograph equipped with an FID. This method, adapted from McAuliffe (1971), has excellent sensitivity for many alkanes including pentane.

Results

Water Chemistry

Sampled features are listed in table 1 with GPS locations and results of measurements made at the time of sampling. Many of these features were also sampled in the early 1990s by Janik and others (1994), who included chemical analyses from even earlier studies in their data tables. For features listed in Janik and others (1994), the ID number used by those authors, the number of analyses they report, and the years spanned by those analyses are given. Specific conductance increases with ionic strength and is a qualitative measure of salinity. Water supply wells all have values below 1,200 microsiemens per centimeter (mS/cm); coastal springs and geothermal fluids have much higher values due to the greater influence of seawater, which for reference has a specific conductance of about 50,000 mS/cm. Dissolved oxygen in active water supply wells is at or near concentrations expected for local rainwater, showing that dissolved oxygen is largely conserved in the shallow groundwater from recharge to withdrawal. Dissolved oxygen is somewhat depleted in warm waters, such as the monitoring wells and most springs. The PGV fluids were all expected to be oxygen-free; the tiny amounts of dissolved oxygen detected may reflect the fact that air could not be completely excluded from the container housing the pH and oxygen probes. Note that the temperature reported for well samples is that of the water in the collection container, not actual down-hole temperature.

Table 1. Location and type of features sampled and results of on-site measurements. Last 4 columns give the site ID number used in Janik and others (1994), the number of samples they report for each site, and the years spanned by those samples.

[SW, supply well; MW, monitoring well; IW, injection well; PW, production well; B, brine pipeline; S, steam pipeline; °C, degrees Celsius; µS/cm, microsiemens per centimeter at 25 degrees Celsius; DO, dissolved oxygen; mg/L, milligrams per liter; nm, not measured]

Sample number	Location	Date	Type	Temp, in °C	Sp. Cond. µS/cm	DO in mg/L	pH	Easting NAD 83	Northing NAD 83	Janik ID	No. of samples	Earliest	Latest
PG14-01	Keonepoko Nui Well #2	04/28/14	SW	19.6	118	9.1	7.76	293816	2158979				
PG14-02	Keonepoko Nui Well #1	04/28/14	SW	19.4	121	9.0	7.80	293816	2159010	3188-01	2	1991	1992
PG14-03	Keauohana #1	04/28/14	SW	23.1	348	8.8	8.24	295002	2147670	2487-01	8	1972	1992
PG14-04	Keauohana #2	04/28/14	SW	23.3	598	8.6	8.10	295012	2147673	2487-02	1	1974	1974
PG14-05	Pohoiki Pond	04/29/14	Spring	35.0	13270	6.5	7.66	306493	2152557	2780-S1	5	1974	1992
PG14-06	Allison Spring	04/29/14	Spring	31.7	17720	5.5	7.28	307173	2153020	2780-S2	1	1974	1974
PG14-07	Hawaiian Shores Well	04/29/14	SW	21.4	202	8.4	7.68	297887	2159638	3185-02	2	1972	1974
PG14-08	Hawaiian Beaches Well #1	04/29/14	SW	21.9	159	8.6	7.61	297480	2159231	3185-01	4	1962	1992
PG14-09	Hawaiian Beaches Well #2	04/29/14	SW	22.7	169	8.5	7.65	297498	2159247				
PG14-10	10-P-5 (MW-1)	04/30/14	MW	39.5	620	4.8	7.45	301459	2155283	2983-01	6	1991	1992
PG14-11	10-P-7 (MW-3)	04/30/14	MW	40.4	622	4.8	7.44	301421	2155350	2883-02	1	1992	1992
PG14-12	MW-2	04/30/14	MW	29.7	2770	0.7	8.08	301994	2154441	2883-07	7	1991	1993
PG14-13	Pad A (Injectate)	04/30/14	IW	32.8	22800	0.4	4.05	301606	2154684				
PG14-14B	KS-5 Brine	04/30/14	PW_B	24.6	26100	0.7	6.59	301407	2154528				
PG14-14S	KS-5 Steam	04/30/14	PW_S	24.1	72	0.0	4.03	301407	2154528				
PG14-15	Vacation Land Roney	05/01/14	Spring	29.7	10040	6.2	7.59	308750	2156177	2979-S1	1	1991	1991
PG14-16	Ahala Nui County Park	05/01/14	Spring	34.1	14890	5.1	7.33	307667	2153731				
PG14-17	Keahialaka Pond	05/01/14	Spring[1]	28.6	8990	6.9	7.24	306132	2152069				
PG14-18	Lighthouse Spring	05/01/14	Spring	26.6	7920	8.6	7.36	310185	2158715	3178-S1	2	1991	1992
PG14-19	Kapoho Shaft	12/09/14	SW[2]	25.6	1086	2.6	6.87	307280	2157350	3080-02	5	1974	1975
PG14-20	Pohoiki Pond	12/09/14	Spring	35.7	13970	nm	7.32	306495	2152557	2780-S1	5	1974	1992
PG14-21	Ahala Nui County Park north	12/09/14	Spring	34.0	15400	nm	7.29	307669	2153740				
PG14-22	Ahala Nui County Park south	12/09/14	Spring	34.3	18020	nm	7.24	307655	2153722				
PG14-23	Keonepoko Nui Well #2	12/10/14	SW	19.9	120	8.3	6.92	293816	2158986				
PG14-24	Pāhoa Well #2	12/10/14	SW	23.3	133	7.7	7.73	295977	2155842				
PG14-25	Vacation Land Roney	12/10/14	Spring	31.0	10390	6.5	7.97	308750	2156177	2979-S1	1	1991	1991

[1]Keahialaka Pond had no visible point of water inflow.

[2]No longer in use.

Table 2. Concentrations of major and minor dissolved species in milligrams per liter (mg/L). Total alkalinity is expressed as HCO_3; NO_3 expressed as N; PO_4 expressed as P. Balance is calculated as 2(C−A)/(C+A) in percent, where C represents the cations and A represents the anions in milliequivalents per liter (meq/L).

[nm, not measured]

Sample number	Location	B mg/L	Ba mg/L	Br mg/L	Ca mg/L	Cl mg/L	F mg/L	HCO_3 mg/L	K mg/L	Li mg/L
PG14-01	Keonepoko Nui Well #2	0.009	0.002	<0.01	7.07	4.02	0.16	56	2.6	<0.001
PG14-02	Keonepoko Nui Well #1	0.008	0.002	<0.01	7.31	4.16	0.17	56	2.5	<0.001
PG14-03	Keauohana #1	0.028	0.003	0.24	8.78	75	0.21	32	3.7	0.005
PG14-04	Keauohana #2	0.039	0.004	0.49	12.4	150	0.24	34	6.2	0.004
PG14-05	Pohoiki Pond	1.17	<0.025	14.5	112	4,210	1.0	52	103	0.10
PG14-06	Allison Spring	1.50	<0.025	19.0	136	5,500	1.0	55	140	0.13
PG14-07	Hawaiian Shores Well	0.013	0.002	0.11	5.24	33.2	0.21	38	3.6	0.001
PG14-08	Hawaiian Beaches Well #1	0.012	0.002	0.06	4.73	20.6	0.22	40	3.4	0.001
PG14-09	Hawaiian Beaches Well #2	0.013	0.002	0.07	5.14	23.0	0.22	38	3.5	0.002
PG14-10	10-P-5 (MW-1)	0.28	0.007	0.06	27.4	22.0	0.38	30	12.1	0.025
PG14-11	10-P-7 (MW-3)	0.28	0.006	0.06	26.8	23.0	0.38	32	12.0	0.024
PG14-12	MW-2	0.29	0.014	2.62	41	750	0.27	52	22.8	0.02
PG14-13	Pad A (Injectate)	4.6	3.7	27.0	173	7,950	1.0	nm	893	2.0
PG14-14B	KS-5 Brine	6.0	3.0	30.0	147	9,120	1.0	8	1,030	2.2
PG14-14S	KS-5 Steam	0.126	0.006	0.04	0.38	14.1	0.01	nm	2.0	0.003
PG14-15	Vacation Land Roney	0.95	<0.013	11.0	90	3,130	1.0	48	83.4	0.08
PG14-16	Ahala Nui County Park	1.41	<0.025	16.5	134	4,840	1.0	49	135	0.15
PG14-17	Keahialaka Pond	0.75	<0.013	9.5	66	2,800	0.50	49	62.7	0.04
PG14-18	Lighthouse Spring	0.68	<0.013	8.3	78	2,410	0.75	46	58.7	0.05
PG14-19	Kapoho Shaft	0.081	0.007	0.35	75	128	0.23	429	8.2	<0.002
PG14-20	Pohoiki Pond	1.50	<0.041	15.5	121	4,450	0.95	64	104	0.065
PG14-21	Ahala Nui County Park north	1.78	<0.041	18.0	141	5,200	1.0	59	136	0.13
PG14-22	Ahala Nui County Park south	1.72	<0.041	20.5	152	5,850	1.0	61	146	0.14
PG14-23	Keonepoko Nui Well #2	0.012	0.002	<0.01	6.9	4.1	0.18	59	2.5	<0.001
PG14-24	Pāhoa Well #2	0.023	0.002	0.010	4.2	4.8	0.29	54	3.4	0.001
PG14-25	Vacation Land Roney	1.17	<0.021	11.5	101	3,220	1.2	58	87	0.10

Concentrations of the major and minor dissolved species are reported in table 2. Sodium is the dominant cation in all of the waters and chloride the dominant anion in the coastal springs and PGV fluids, reflecting the influence of seawater. Bicarbonate (HCO_3) is the dominant anion in some of the water supply wells. Several species, such as B, K, Li, Rb, and SiO_2, are notably enriched in the PGV injectate and brine, while Mg is nearly absent. This pattern is a nearly universal characteristic of high-temperature geothermal systems worldwide. SiO_2 values in field-diluted PGV samples were within 5 percent of the nondiluted values, indicating that polymerization had not reduced SiO_2 concentrations in the undiluted samples. The charge balance between cations and anions is a qualitative measure of analytical error and is less than 5 percent for most of the samples. The balance exceeds 10 percent only for the steam condensate, which is very dilute and subject to larger analytical errors.

Trace elements, including several metals of environmental concern, the stable isotopes of water, and NH_3 and H_2S concentrations in the PGV samples are reported in table 3. In general, trace metal levels are low in all of the waters, including the PGV fluids, as pointed out by Thomas (1990). Concentrations of arsenic in the PGV fluids and in some springs exceed the drinking water standard but are actually low in comparison to geothermal fluid compositions worldwide, which often contain more than 1 milligram per liter (mg/L). The iodometric sulfide titration measures all reduced sulfur species (HS^-, $S_2O_3^-$, etc.), but the nearly

Table 2. —Continued.

Sample number	Location	Mg mg/L	Na mg/L	NO_3 mg/L	PO_4 mg/L	Rb mg/L	SiO_2 mg/L	SO_4 mg/L	Sr mg/L	TDS mg/L	Balance %
PG14-01	Keonepoko Nui Well #2	4.66	9.78	0.25	0.08	<0.01	53	4.5	0.029	135	7.3
PG14-02	Keonepoko Nui Well #1	4.80	9.89	0.26	0.07	<0.01	52	4.7	0.030	139	8.6
PG14-03	Keauohana #1	3.99	50.4	0.27	0.08	<0.01	50	14.1	0.046	239	3.3
PG14-04	Keauohana #2	7.90	86.5	0.24	0.05	<0.02	51	23.7	0.080	367	–2.1
PG14-05	Pohoiki Pond	253	2,370	1.5	<0.5	<0.25	89	610	1.63	7820	–0.2
PG14-06	Allison Spring	321	3,080	1.5	<0.5	<0.25	88	780	2.05	10,100	–1.0
PG14-07	Hawaiian Shores Well	5.66	23.4	0.26	0.06	<0.01	56	7.8	0.031	174	5.3
PG14-08	Hawaiian Beaches Well #1	4.12	18.1	0.25	0.07	<0.01	58	6.4	0.025	156	4.2
PG14-09	Hawaiian Beaches Well #2	4.42	19.6	0.25	0.06	<0.01	59	6.7	0.026	160	8.9
PG14-10	10-P-5 (MW-1)	14.6	67.4	0.26	<0.02	0.027	106	218	0.095	511	–2.0
PG14-11	10-P-7 (MW-3)	14.5	68.0	0.20	<0.02	0.026	106	220	0.096	513	–2.9
PG14-12	MW-2	29.3	460	<0.01	<0.01	<0.05	62	136	0.34	1560	0.9
PG14-13	Pad A (Injectate)	0.2	4,420	7.0	1.0	2.36	597	17.0	5.17	14,100	–0.3
PG14-14B	KS-5 Brine	0.1	5,180	2.0	<1	2.74	714	25.0	4.40	16,300	0.5
PG14-14S	KS-5 Steam	0.004	9.4	<0.01	<0.01	<0.01	2	0.5	0.010	29	16.5
PG14-15	Vacation Land Roney	188	1,770	1.0	<0.5	<0.13	73	515	1.27	5,910	–1.1
PG14-16	Ahala Nui County Park	277	2,740	1.5	<0.5	<0.25	97	675	1.90	8,970	0.6
PG14-17	Keahialaka Pond	172	1,580	1.5	<0.25	<0.13	61	408	1.01	5,210	–0.5
PG14-18	Lighthouse Spring	152	1,380	0.50	<0.25	<0.13	60	393	1.05	4,590	1.3
PG14-19	Kapoho Shaft	40	94.8	2.4	0.09	<0.02	60	16.4	0.29	854	3.0
PG14-20	Pohoiki Pond	263	2,430	1.5	<0.5	<0.41	91	640	1.71	8,180	–2.9
PG14-21	Ahala Nui County Park north	293	2,850	1.5	<0.5	<0.41	97	715	2.01	9,510	–2.6
PG14-22	Ahala Nui County Park south	340	3,150	0.50	<0.5	<0.41	92	815	2.25	10,600	–3.7
PG14-23	Keonepoko Nui Well #2	4.55	9.4	0.22	0.06	<0.01	52	4.5	0.027	143	0.2
PG14-24	Pāhoa Well #2	3.10	16.5	<0.01	0.05	<0.01	57	12.2	0.020	155	–1.7
PG14-25	Vacation Land Roney	204	1,840	1.0	<0.5	<0.21	81	525	1.40	6,130	1.3

complete partitioning of reduced sulfur into the steam and gas phase—510 mg/L versus 9 mg/L in the brine—shows that the primary reduced sulfur species is H_2S.

Gas Chemistry

The gas bubbles collected from the PGV steam and injectate lines are somewhat similar in bulk composition (table 4). This is expected, given that between these two sampling ports PGV pumps the gas from the steam line into the injectate line. Major constituents in both samples include H_2, CO_2 and H_2S, all of which are commonly found in geothermal systems. The N_2 and Ar are likely derived from the atmosphere, in part from air dissolved in rainwater or seawater that ultimately recharges the geothermal reservoir. The presence of oxygen at low levels indicates that only a small amount of air contamination occurred during sample collection.

The noticeable differences in composition between the steam and injectate samples (table 4) mainly reflect variation in the solubility of the individual gas species and the volume ratio between gas bubbles and water in the sampling line. More soluble gases like H_2S and CO_2 are less able to partition into the small bubbles that form in the injectate sampling line; they remain in solution and are therefore at lower concentrations in the injectate gas sample relative to the steam sample. Less soluble gases like H_2, Ar, and N_2 get concentrated in those small bubbles; for example, N_2 is nearly a factor of 2 higher in the injectate gas sample.

Table 3. Concentrations of trace metals, NH_3, and H_2S, in milligrams per liter (mg/L), and stable isotopes of water, in per mil. NH_3 values expressed as N; H_2S values are total reduced S expressed as H_2S.

[nm, not measured]

SAMPLE #	Location	Al mg/L	As mg/L	Cd mg/L	Co mg/L	Cr mg/L	Cu mg/L	Fe mg/L	Mn mg/L
PG14-01	Keonepoko Nui Well #2	<0.002	0.001	<0.001	<0.001	0.003	0.001	<0.003	<0.001
PG14-02	Keonepoko Nui Well #1	0.002	<0.001	<0.001	<0.001	0.003	<0.001	<0.003	<0.001
PG14-03	Keauohana #1	0.006	0.001	<0.001	<0.001	<0.001	<0.001	0.004	<0.001
PG14-04	Keauohana #2	<0.004	<0.002	<0.002	<0.002	<0.002	<0.002	<0.006	<0.002
PG14-05	Pohoiki Pond	<0.05	<0.025	<0.025	<0.025	<0.025	<0.025	<0.075	<0.025
PG14-06	Allison Spring	<0.05	0.03	<0.025	<0.025	<0.025	<0.025	<0.075	<0.025
PG14-07	Hawaiian Shores Well	<0.002	0.001	<0.001	<0.001	0.001	0.002	<0.003	<0.001
PG14-08	Hawaiian Beaches Well #1	<0.002	<0.001	<0.001	<0.001	0.002	<0.001	<0.003	<0.001
PG14-09	Hawaiian Beaches Well #2	0.002	0.001	<0.001	<0.001	0.001	0.003	<0.003	<0.001
PG14-10	10-P-5 (MW-1)	0.003	<0.001	<0.001	<0.001	<0.001	<0.001	0.013	0.002
PG14-11	10-P-7 (MW-3)	0.003	0.001	<0.001	<0.001	<0.001	<0.001	0.015	0.005
PG14-12	MW-2	<0.01	<0.005	<0.005	<0.005	<0.005	<0.005	0.018	0.04
PG14-13	Pad A (Injectate)	0.18	0.053	<0.05	<0.05	<0.05	<0.05	0.17	0.3
PG14-14B	KS-5 Brine	0.24	0.069	<0.05	<0.05	<0.05	0.065	<0.15	0.6
PG14-14S	KS-5 Steam	0.007	<0.001	<0.001	<0.001	<0.001	<0.001	0.02	0.022
PG14-15	Vacation Land Roney	<0.026	0.02	<0.013	<0.013	<0.013	<0.013	<0.039	<0.013
PG14-16	Ahala Nui County Park	<0.05	<0.025	<0.025	<0.025	<0.025	<0.025	<0.075	<0.025
PG14-17	Keahialaka Pond	<0.026	0.01	<0.013	<0.013	<0.013	<0.013	<0.039	<0.013
PG14-18	Lighthouse Spring	<0.026	0.01	<0.013	<0.013	<0.013	<0.013	<0.039	<0.013
PG14-19	Kapoho Shaft	<0.01	<0.02	<0.002	<0.002	<0.002	0.002	<0.006	<0.002
PG14-20	Pohoiki Pond	<0.2	<0.04	<0.04	<0.04	<0.04	<0.04	<0.12	<0.04
PG14-21	Ahala Nui County Park north	<0.2	<0.04	<0.04	<0.04	<0.04	<0.04	<0.12	<0.04
PG14-22	Ahala Nui County Park south	<0.2	<0.04	<0.04	<0.04	<0.04	<0.04	<0.12	<0.04
PG14-23	Keonepoko Nui Well #2	<0.005	<0.01	<0.001	<0.001	0.003	0.002	<0.003	<0.001
PG14-24	Pāhoa Well #2	<0.005	<0.01	<0.001	<0.001	0.001	0.006	<0.003	<0.001
PG14-25	Vacation Land Roney	<0.1	<0.21	<0.2	<0.2	<0.2	<0.2	<0.06	<0.2

The gases contain trace amounts of numerous hydrocarbons, from methane to compounds as large as pentane. Pentane and other hydrocarbons were clearly detectable on the TCD detector used to quantify major constituents, even though this detector is not highly sensitive to hydrocarbons. The more precise values obtained from the FID are used in further discussion, but either set of results would produce the same conclusions.

The alkane hydrocarbon concentrations (as parts-per-million by volume) are shown in figure 2. Alkanes up to butane, which has two isomers, are enriched about two-fold in the injectate relative to the steam sample. This enrichment likely reflects their low aqueous solubilities, similar to those of Ar and N_2, which show comparable enrichments (table 4). Thus, no in-plant source is required to explain the fact that these alkane concentrations are higher in the injectate than in the produced steam. Pentane, in contrast, shows a six-fold enrichment in the injectate relative to the steam (fig. 2), consistent with an in-plant source.

The alkane hydrocarbons consist mainly of methane, and both samples show successively decreasing amounts of ethane, propane, and butane (fig. 2). This is the pattern expected in virtually any natural gas, whether from a sedimentary basin or a geothermal system, where alkanes form from the thermal breakdown of organic matter (for example, kerogen) in the reservoir (Darling, 1998; Tassi and others, 2007). Successively higher molecular weight alkanes like pentane and hexane normally continue the trend of decreasing abundance. The PGV samples instead show a conspicuous increase in pentane, again consistent with an artificial source. The gas in the

Table 3. —Continued.

SAMPLE #	Location	Mo mg/L	Ni mg/L	Se mg/L	Zn mg/L	NH_3 mg/L	H_2S mg/L	δD per mil	$\delta^{18}O$ per mil
PG14-01	Keonepoko Nui Well #2	<0.001	<0.001	<0.005	0.006	nm	nm	−22.1	−4.43
PG14-02	Keonepoko Nui Well #1	<0.001	<0.001	<0.005	0.006	nm	nm	−23.5	−4.51
PG14-03	Keauohana #1	<0.001	<0.001	<0.005	0.005	nm	nm	−15.0	−3.61
PG14-04	Keauohana #2	<0.002	<0.002	<0.01	0.005	nm	nm	−14.6	−3.58
PG14-05	Pohoiki Pond	<0.025	<0.025	<0.125	<0.05	nm	nm	−9.9	−2.54
PG14-06	Allison Spring	<0.025	<0.025	<0.125	<0.05	nm	nm	−9.1	−2.36
PG14-07	Hawaiian Shores Well	<0.001	<0.001	<0.005	0.007	nm	nm	−13.7	−3.50
PG14-08	Hawaiian Beaches Well #1	<0.001	<0.001	<0.005	0.004	nm	nm	−13.9	−3.50
PG14-09	Hawaiian Beaches Well #2	<0.001	<0.001	<0.005	0.007	nm	nm	−15.0	−3.46
PG14-10	10-P-5 (MW-1)	0.002	<0.001	<0.005	0.004	nm	nm	−12.1	−3.18
PG14-11	10-P-7 (MW-3)	0.002	<0.001	<0.005	0.084	nm	nm	−12.7	−3.30
PG14-12	MW-2	<0.005	<0.005	<0.025	<0.01	nm	nm	−12.1	−3.20
PG14-13	Pad A (Injectate)	<0.05	<0.05	<0.25	<0.1	< 0.04	122	−8.1	−1.55
PG14-14B	KS-5 Brine	<0.05	<0.05	<0.25	<0.1	< 0.04	9	−5.6	−0.80
PG14-14S	KS-5 Steam	<0.001	<0.001	0.01	<0.002	< 0.04	510	−6.1	−3.00
PG14-15	Vacation Land Roney	<0.013	<0.013	<0.065	<0.026	nm	nm	−8.3	−2.51
PG14-16	Ahala Nui County Park	<0.025	<0.025	<0.125	<0.05	nm	nm	−8.3	−2.32
PG14-17	Keahialaka Pond	<0.013	<0.013	<0.065	<0.026	nm	nm	−10.9	−2.80
PG14-18	Lighthouse Spring	<0.013	<0.013	<0.065	<0.026	nm	nm	−10.5	−2.91
PG14-19	Kapoho Shaft	<0.002	<0.002	<0.01	<0.004	nm	nm	−15.4	−3.44
PG14-20	Pohoiki Pond	<0.04	<0.04	<0.2	<0.08	nm	nm	−9.0	−2.31
PG14-21	Ahala Nui County Park north	<0.04	<0.04	<0.2	<0.08	nm	nm	−7.4	−2.14
PG14-22	Ahala Nui County Park south	<0.04	<0.04	<0.2	<0.08	nm	nm	−7.9	−2.04
PG14-23	Keonepoko Nui Well #2	<0.001	<0.001	<0.005	0.015	nm	nm	−20.7	−4.42
PG14-24	Pāhoa Well #2	0.001	<0.001	<0.005	0.062	nm	nm	−14.1	−3.75
PG14-25	Vacation Land Roney	<0.2	<0.2	<0.1	<0.04	nm	nm	−8.7	−2.44

injectate stream also contains a significant amount of pentene (table 4), a compound not detected in the produced steam. The PGV gases contain no hexane, which would likely be detectable if all of the other hydrocarbons derived from natural degradation of organic matter in the reservoir.

Thermal degradation of large hydrocarbons into smaller ones is a complex process (Darling, 1998). Although a full explanation of the hydrocarbon abundance patterns in the PGV gases cannot be provided, several assertions can be supported. The working fluid used by PGV is nearly pure pentane (99.2 percent according to the material safety data sheet supplied by PGV). At some point in the plant, perhaps in the heat exchanger, pentane enters the flow system. Some degradation to pentene must occur upstream from the injectate sampling port (table 4). Such a rapid reaction is possible in this case because H_2S is known to catalyze hydrocarbon degradation under certain conditions (Xia and others, 2014). The pentene apparently breaks down into smaller hydrocarbons after injection into the reservoir, because it is not present in the produced steam (table 4). The injected pentane may also continue to break down into smaller hydrocarbons, but enough survives within the reservoir that it exceeds the abundance of butane (both isomers) in the produced steam. It is not possible with existing data to precisely distinguish hydrocarbons generated by thermal breakdown of organic matter in the reservoir from those produced by pentane degradation. Although some of the pentane may come from natural sources in the reservoir, it is clear from the data that the geothermal plant must be an important source.

Table 4. Composition (in volume percent) of gas bubbles in samples collected from the Puna Geothermal Venture steam and injectate lines.

[TCD, results from the gas chromatograph equipped with a thermal conductivity detector; FID, results from the gas chromatograph equipped with a flame ionization detector; nm, not measured]

Sample	Method	PG14-14S steam line TCD	PG14-14S steam line FID	PG14-13 injectate line TCD	PG14-13 injectate line FID
		Bulk gas analysis			
Helium	He	<0.01	nm	<0.01	nm
Hydrogen	H_2	33.0	nm	42.2	nm
Argon	Ar	0.276	nm	0.412	nm
Oxygen	O_2	0.346	nm	0.120	nm
Nitrogen	N_2	15.4	nm	27.2	nm
Carbon Dioxide	CO_2	27.8	nm	21.4	nm
Hydrogen Sulfide	H_2S	25.2	nm	10.5	nm
Carbon Monoxide	CO	<0.001	nm	<0.001	nm
		Hydrocarbons			
Methane	CH_4	0.226	0.193	0.421	0.372
Ethylene	C_2H_4	0.0003	0.0003	0.0003	0.0003
Ethane	C_2H_6	0.017	0.0148	0.029	0.0267
Propylene	C_3H_6	0.003	0.0027	0.003	0.0025
Propane	C_3H_8	0.006	0.0068	0.012	0.0131
Butane	$n\text{-}C_4H_{10}$	0.001	0.0016	0.003	0.0036
Isobutane	$i\text{-}C_4H_{10}$	0.002	0.0025	0.004	0.0056
Pentene	C_5H_{10}	<0.001	<0.0002	0.014	0.0086
Pentane	C_5H_{12}	0.005	0.0060	0.031	0.0398
Hexane	C_6H_{14}	<0.01	<0.003	<0.01	<0.004

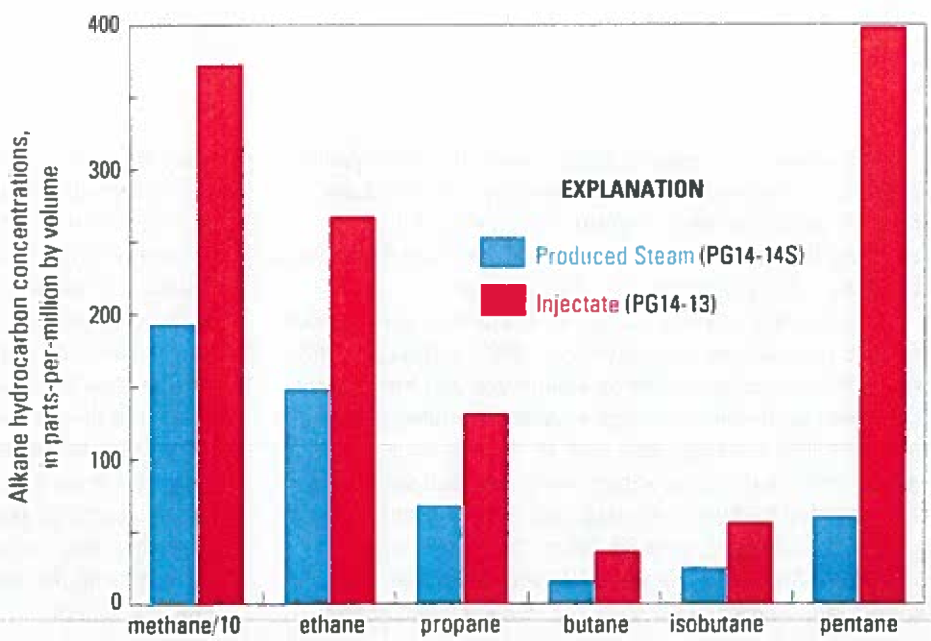

Figure 2. Concentration of alkane hydrocarbons (in parts-per-million by volume) in gas samples from the steam (blue) and injectate (red) pipelines at Puna Geothermal Venture. Concentration of methane divided by 10.

Table 5. Concentrations of dissolved hydrocarbons in micromoles per kilogram (µmol/kg) for all samples containing a hydrocarbon larger than methane. DIC and serum bottle samplers discussed in text.

[nm, not measured]

Sample	PG14-14S Steam		PG14-13 Injectate[1]	PG14-14B Brine		PG14-12 MW-2		PG14-01 Keonepoko Nui #2		PG14-19 Kapoho Shaft		PG14-24 Pāhoa #2	
Method	(DIC)	(serum)	(serum)	(DIC)	(serum)	(DIC)	(serum)	(DIC)	(serum)	(DIC)	(serum)	(DIC)	(serum)
CH_4	1.6	1.1	3.9	0.03	0.02	0.34	1.2	0.004	0.002	0.04	0.008	0.04	0.006
C_2H_4	<0.01	nm	nm	0.007	nm	<0.01	nm	<0.01	nm	<0.01	nm	<0.01	nm
C_2H_6	0.18	0.11	0.35	0.007	0.002	0.01	0.01	0.008	<0.001	0.005	<0.001	0.008	<0.001
C_3H_6	0.08	nm	nm	0.009	nm	<0.01	nm	<0.01	nm	0.02	nm	<0.01	nm
C_3H_8	0.05	0.01	0.06	<0.01	0.001	0.01	0.01	<0.01	<0.001	0.007	<0.001	<0.01	<0.001
n-C_4H_{10}	0.01	0.005	0.02	<0.01	0.0003	0.01	0.005	0.007	<0.001	<0.01	<0.001	<0.01	<0.001
i-C_4H_{10}	0.01	0.004	0.03	0.004	<0.001	0.003	0.001	<0.01	<0.001	<0.01	<0.001	<0.01	<0.001
C_5H_{10}	<0.01	nm	nm	0.02	nm	<0.01	nm	<0.01	nm	<0.01	nm	<0.01	nm
C_5H_{12}	0.03	0.01	0.14	<0.01	<0.001	<0.01	0.001	0.008	<0.001	<0.01	<0.001	<0.01	<0.001
C_6H_{14}	<0.05	<0.001	<0.001	<0.05	<0.001	<0.05	<0.001	<0.05	<0.001	<0.05	<0.001	<0.05	<0.001

[1] DIC bottle broken in shipment

Pentane in Water Samples

For the purpose of this study, a criterion is needed to identify a PGV-related hydrocarbon component in groundwater that might also contain hydrocarbons from natural sources. An excess of pentane relative to total butane is an obvious criterion to apply, given the gas sample results discussed above, but for thoroughness the water samples collected for pentane analysis were analyzed for the full hydrocarbon abundance patterns as was done for the gas samples. Traces of methane were found at every site, but this is a common gas that can be formed through microbial activity in many groundwaters. The results for every site where a hydrocarbon larger than methane was detected are shown in table 5.

Two caveats about these data must be acknowledged. Collection and analysis of water samples containing these highly insoluble gases involves several steps where gas concentrations can be altered. For example, the tiny bubbles that frequently form during collection can result in significant depletion or enrichment of gas within the actual water sample. Thus even duplicate samples analyzed by the same method can show large differences. A particular concern for this sample set is the low concentration of most hydrocarbons. The original goal of the study was to attain a detection limit for pentane of 1 microgram/kilogram of water, which equates to 0.014 micromoles/kilogram (µmol/kg). The method using the DIC bottles attained this detection limit, while the serum bottle method achieved a much lower detection limit of 0.001 µmol/kg. For completeness, a value is reported in table 5 for every case where an identifiable peak was seen in the chromatogram, even in cases where the concentration was below the stated detection limit. The identity of the compound is fairly certain; however, for the many values near the respective detection limits, the concentration carries a large uncertainty.

Despite the uncertainties, pentane exceeds total butane in the steam (using both sampling methods) and especially in the injectate (table 5). Because visible gas loss occurred during collection of these samples (bubbles in the collection tubing), these values are minimum concentrations. The brine sample is gas poor by comparison, having lost nearly all of its gas to the steam phase. A few hydrocarbons are detectable at low levels, mainly alkenes which are more soluble than alkanes. Several hydrocarbons were detected by both methods in MW-2 near the plant, including a trace of pentane in the serum bottle.

Hydrocarbons larger than methane were only detected at three other sites (table 5) and, in each case, only detected in the DIC bottles at levels close to the detection limits of that method. The April DIC sample from Keonepoko Nui well #2 showed several alkane peaks, including pentane, but neither of the two serum bottles from that well showed any hydrocarbons other than methane. This well was resampled in December, and no hydrocarbons (other than methane) were detected by either method. Thus the alkane detects for the one DIC sample, all of which are less than 0.01 mmol/kg, may reflect low-level contamination of that sample bottle during initial evacuation or analysis. Pentane was not detected at any other site, but DIC bottles from Kapoho Shaft and the Pāhoa supply well showed some trace hydrocarbons larger than methane. Serum bottles from these wells showed only methane, so perhaps the results from these DIC bottles also reflect low-level contamination in the bottles. However, such hydrocarbons can also be produced from organic matter (for example, pipe grease) within well plumbing systems and be flushed out intermittently as the well pumps are cycled on and off. Samples collected only minutes apart could reflect this variation, and thus the data should not be automatically disregarded.

Alkane abundances are shown in figure 3 for the sites where pentane was detected. The abundances in MW-2 (PG14-12) do not show the pentane enrichment pattern seen in the injectate, and instead show a steady decrease in abundance with increasing molecular size. If these alkanes originated as pentane from the PGV injectate, thermal degradation of that pentane has proceeded to the point where the abundance pattern is indistinguishable from that expected to result from degradation of natural organic matter. The alkane abundances in the Keonepoko Nui #2 (PG14-01) DIC sample from April 2014 look nothing like the pattern in the injectate, MW-2, or any typical groundwater, and are considered unlikely to represent the groundwater feeding this well. Thus there was no clear evidence for PGV-derived pentane in any of the groundwater features we sampled.

Isopropanol

Isopropanol (isopropyl alcohol) is a component of the additive ChemTreat GG442 used by PGV to control corrosion in pipelines at the plant. The concentration range of isopropanol in the additive is listed as 1–5 percent by weight in the material safety data sheet obtained from PGV, and a more precise figure could not be obtained from the manufacturer. PGV records for the month of April 2014 show that, on an average day, 52 gallons of additive are mixed into 5 million gallons of injectate, a mixing ratio of about 10 mg of additive per liter of injectate, ignoring density differences between the two fluids. Isopropanol should thus constitute between 100 and 500 micrograms per liter (μg/L) of the injectate. The measured isopropanol concentration in the sample of injectate (PG14-13) was 496 mg/L, consistent with 5 percent isopropanol in the additive.

Unlike pentane, isopropanol is quite soluble in water, so that partitioning into gas bubbles during sample collection at ambient temperature is not a significant concern. At high temperatures, volatility does become important, and most of the injected isopropanol that survives transport through the reservoir to the production well partitions into the steam line. The isopropanol concentration in PG14-14S was 60.5 mg/L; that in PG14-14B was 3.8 mg/L. Interestingly, the ratio of isopropanol concentration in injectate to that in steam is 8.2:1, not too different from the pentane ratio for injectate to steam, which is 6.4:1 based on the average pentane concentration in the two steam samples in table 5. Either the two compounds degrade at comparable rates in the reservoir, or they degrade very little and the concentration ratios reflect the reservoir dilution factor. Isopropanol was below detection (<0.8 mg/L) in all samples, except for the three collected from the plant, and thus provided no evidence for PGV-derived fluid in the groundwaters.

Isopropanol analysis also yielded results for 37 other VOCs. The complete list of these compounds, representative detection limits, and instances of detection are shown in table 6. In nearly every instance, concentrations are near the detection limits, and the reported concentrations should be viewed with caution unless confirmed by future sampling. The single exception is the reported concentration of isopropyl acetate in the injectate sample. This compound may be an impurity in the ChemTreat GG442 additive or a reaction product derived from isopropanol in the piping system. Apart from isopropanol and possibly isopropyl acetate, the compounds in table 6 are not known to be contaminants specifically related to geothermal production.

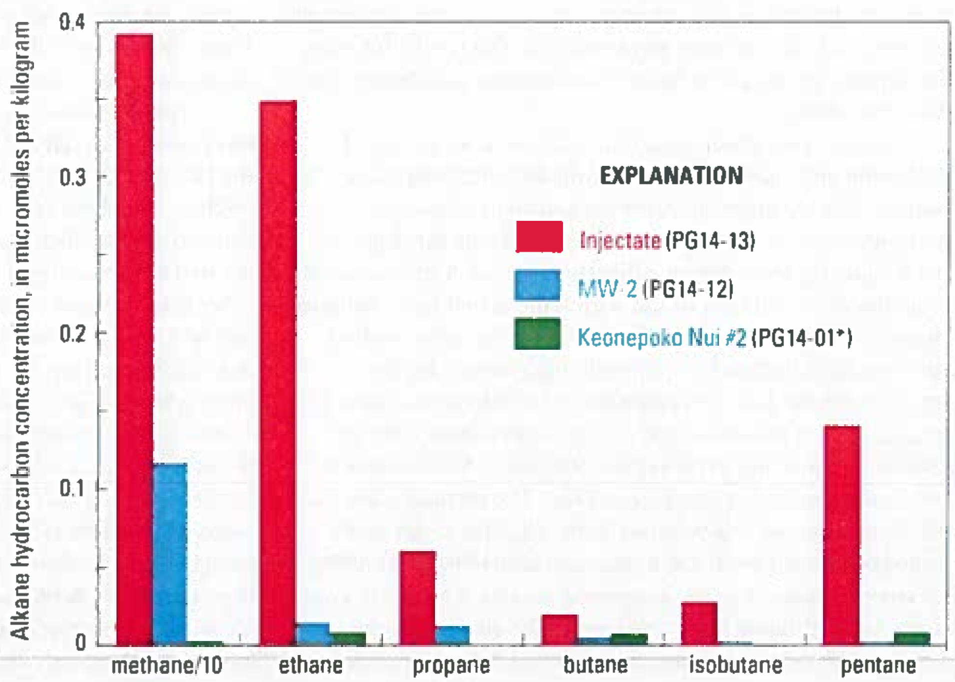

Figure 3. Concentration of alkane hydrocarbons (in μmol/kg) in both wells where pentane was detected, MW-2 (PG14-12) and Keonepoko Nui #2 (PG14-01—*DIC sample only). Red bars show concentrations in the injectate sample (PG14-13) for comparison. Concentration of methane divided by 10.

Injectate Composition Over Time

Direct leakage of deep geothermal water or gas into shallow groundwater would likely first be detected at sites nearest to the plant, in this case the three monitoring wells. Contaminant transport in shallow groundwater to remote locations like the coastal warm springs 5–10 km away would be controlled by groundwater velocity from the LERZ down to the coast. Scholl and others (1996) used tritium data to estimate residence times of 18–25 years for the groundwater feeding these springs, though some of this time could include periods of slow flow through dike-impounded zones within the LERZ. Hydraulic conductivity between the rift and the coastal warm springs is thought to be in the range of 1–6 km/d (Imada, 1984; Takasaki; 1993; Gingerich, 1995). Given the hydraulic gradient and effective porosity south of the rift zone (Gingerich, 1995), groundwater flow expressed as particle velocity relevant to contaminant transport is likely to range from about 3 to 30 m/d (Sorey and Colvard, 1994). Thus it might require several years for any contaminant derived from the PGV plant to appear at the springs. Evaluation of contamination in these features also requires some knowledge of geothermal fluid composition in previous years.

The injectate is sampled on a regular basis to satisfy conditions of the operating permit. Bimonthly samples are analyzed for a suite of inorganic species similar to that presented in tables 2 and 3. Samples of gas from the noncondensable gas line, taken just before it flows into the injectate stream, are also analyzed. Additional samples of the injectate are collected twice a year for specialized analyses that include a large suite of organic compounds, but not isopropanol. The records are extensive, and we obtained a partial set from the HDOH that provided inorganic chemistry and gas composition for 2008–14 and selected prior years.

Pentane and Isopropanol

Analyses of pentane in injectate apparently began on November 3, 2000, when it constituted 0.632 percent of the noncondensable gas. Values since that time have generally been an order of magnitude lower, and in the samples collected just before and after our sampling were near 0.02 percent (fig. 4). Our gas sample, PG14-13, has a somewhat higher value, near 0.04 percent, but this sample was collected from the injectate pipeline instead of the noncondensable gas line, where samples are normally obtained. The two-fold difference is probably due to solubility effects as discussed above.

Although the rate at which pentane enters the injectate stream continues to show variability (fig. 4), it seems reasonable to assume that the measured concentration of dissolved pentane in our injectate sample, 0.14 mmol/kg (table 5), is representative of average conditions over the past six years. Given the detection limit of 0.001 mmol/kg by the serum bottle method, pentane could be detectable in springs and wells that contain as little as 1 percent injectate. Pentane would thus be a good indicator of leaks in the event of casing failure in an injection well. However, pentane concentrations in the deep reservoir are no doubt substantially less than those in the injectate due to degradation and (or) dilution. Furthermore, pentane could be lost to exsolution during groundwater flow over many kilometers from the PGV area, so the absence of pentane in coastal springs, for example, does not in itself preclude contamination by geothermal fluid.

PGV use of isopropanol began in September 2013, so groundwater transport of this compound would not be expected to extend far (many kilometers) from the plant at the time of our sampling. Our motivation in measuring isopropanol in distal sites was mainly to obtain a complete picture of natural background levels, enhancing possible future use as a tracer.

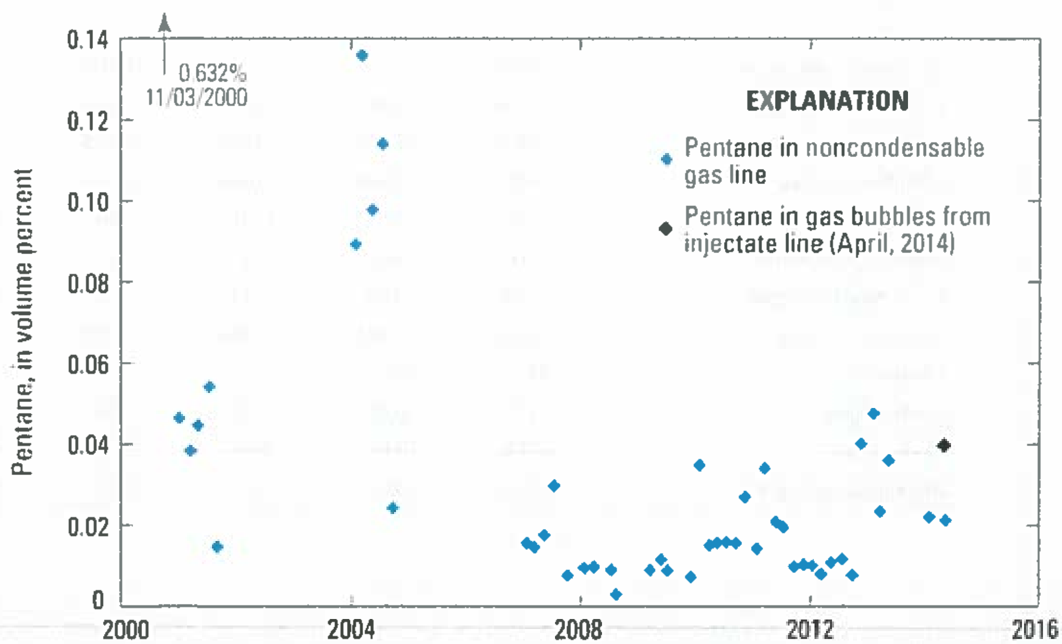

Figure 4. Concentration of pentane (in volume percent) in the noncondensable gas line at Puna Geothermal Venture, as reported in Hawai'i State Department of Health records for 2001, 2004, and 2007–14. Value for initial report of November 3, 2000, is off scale and shown by the arrow. Black diamond shows the pentane concentration we measured in gas bubbles from the injectate line.

Table 6. Volatile organic compounds (VOCs) measured in water samples. VOCs were below detection in all other samples.

[All samples measured in micrograms per liter; detections in bold]

	PG14-01 Keonepoko Nui #2	PG14-02 Keonepoko Nui #1	PG14-12 Monitoring Well 2	PG14-13 PGV injectate	PG14-14S PGV steam	PG14-14B PGV brine
acrolein	<0.24	<0.24	<0.325	<0.599	<0.471	<0.48
hexachlorocyclopentadiene	<1.6	<1.6	<1.6	<1.6	<1.6	<3.2
isophorone	<5	<5	<5	<5	<5	<10
nitrobenzene	<0.6	<0.6	<0.6	<0.6	<0.6	<1.2
1,2-dichloropropane	<0.004	<0.004	<0.004	<0.004	<0.004	<0.008
isopropyl acetate	<0.01	<0.01	<0.01	**0.17**	<0.01	<0.02
propyl acetate	**0.08**	**0.04**	<0.032	<0.032	<0.032	<0.064
1-methoxy-4-(2-propenyl)benzene	<0.6	<0.6	<0.6	<0.6	<0.6	<1.2
2-ethoxyethyl acetate	<4.2	<4.2	<4.2	<4.2	<4.2	<8.4
2-propen-1-ol	<5	<5	<5	<5	<5	<10
alpha-terpineol	<6	<6	<6	<6	<6	<12
butanal	<0.38	<0.38	<0.38	<0.38	**0.2**	**0.2**
crotonaldehyde	<0.48	<0.48	<0.48	<0.48	<0.48	<0.96
acetonitrile	<0.8	<0.8	<0.8	<0.8	<0.8	<1.6
isopropanol	<0.8	<0.8	<0.8	**496**	**60.5**	**3.8**
methyl acetate	<0.14	<0.14	<0.14	<0.14	<0.14	<0.28
1-butanol	<0.8	<0.8	<0.8	<0.8	<0.8	<1.6
tert-butyl alcohol	<0.24	<0.24	**0.24**	<0.248	**0.5**	<0.48
n-pentanal	<0.054	<0.054	<0.054	<0.188	<0.428	**0.04**
2-nitropropane	<0.12	<0.12	<0.12	<0.12	<0.12	<0.24
cyclohexanone	<1.2	<1.2	<1.2	<1.2	<1.2	<2.4
4-methyl-2-pentanol	<0.2	<0.2	<0.2	<0.2	<0.2	<0.4
5-methyl-2-hexanone	<0.022	<0.022	<0.022	<0.0240	<0.0762	<0.044
2-methylpropyl acetate	<0.028	<0.028	<0.028	<0.028	<0.028	<0.056
1-octanol	<1.8	<1.8	<1.8	<1.8	<1.8	<3.6
2-ethyl-1-hexanol	<2	<2	<2	<2	<2	<4
2,6-dimethyl-4-heptanone	<0.032	<0.032	<0.032	<0.032	<0.032	<0.064
1,2,3-trichloropropane	<0.006	<0.006	<0.006	<0.006	<0.006	<0.012
chloropicrin	<0.018	<0.018	<0.018	<0.018	<0.018	<0.036
1,2-dibromoethane	<0.004	<0.004	<0.004	<0.004	<0.004	<0.008
tert-butyl methyl ether	<0.012	<0.012	<0.012	<0.012	<0.012	<0.024
n-nitrosodiethylamine	<3.6	<3.6	<3.6	<3.6	<3.6	<7.2
1,1-dichloro-2-propanone	<0.24	<0.24	<0.24	<0.24	<0.24	<0.48
dimethoxymethane	<0.044	<0.044	<0.044	<0.044	<0.044	<0.088
1,4-dioxane	<0.7	<0.7	<0.7	<0.7	**1**	<1.4
1,3-dioxolane	<0.38	<0.38	<0.38	<0.38	<0.38	<0.76
ethyl acetate	<0.06	<0.06	<0.06	<0.06	<0.06	<0.12
dibromochloropropane	<0.02	<0.02	<0.02	<0.02	<0.02	<0.04

The aqueous solubility of isopropanol at low temperature exceeds that of pentane by a factor of 10^4, suggesting that it would be much more likely to remain in solution during groundwater transport.

Water and Gas Composition of Injectate

Seawater is an important source of fluid for the geothermal reservoir, and thus the chemical composition of PGV fluid has many of the characteristics of seawater. Rainfall is abundant and infiltration rapid in the Puna area (Thomas, 1987; Takasaki, 1993; Ingebritsen and Scholl, 1993; Gingerich, 1995; Scholl and others, 1995), and some of this infiltration reaches the reservoir, causing variable dilution of the seawater component. Injectate monitoring records from HDOH show that NaCl content has nearly doubled since 1995, but that the rate of increase has slowed greatly over the last 15 years (fig. 5). During the last six years the Na and Cl concentrations have been reasonably constant and are near the concentration in our injectate sample, PG14-13. The Na/Cl ratio has followed the seawater dilution line. The injectate has always been low in sulfate, which is almost completely removed into solid phases or converted to reduced forms at the high temperatures in and adjacent to the reservoir. Interestingly, the fluid composition in the HGP-A well showed a similar evolution during its years of production (Thomas, 1987; Janik and others, 1994), leveling off at about the same composition as present-day PGV fluid.

The concentrations of several major species over the past six years, including a sample collected two weeks after our injectate sample, are shown in figure 6. While some species (Ca, total S) show significant short-term variability (fig. 6*B*), long-term trends are not readily apparent.

Gas composition (in the noncondensable gas line) has also been reasonably stable over the past six years and even farther back into the late 1990s (fig. 7), although the minor gases CH_4 and Ar have shown a long-term increases (fig. 7*B*). The dominant gas species are typically H_2 and CO_2, with lesser amounts of N_2 and H_2S. Our gas sample from the injectate line is somewhat richer in H_2 and N_2 and depleted in CO_2 and H_2S due to the

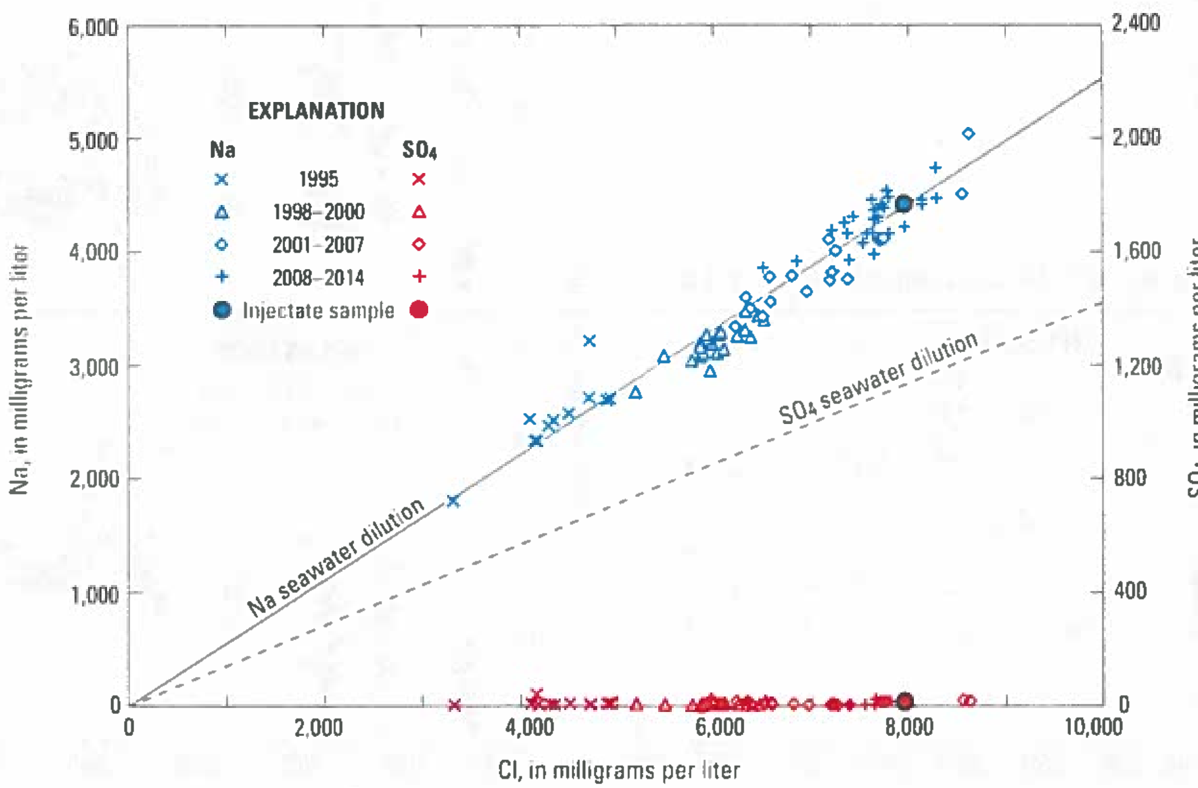

Figure 5. Concentration (in mg/L) of Na (blue) and SO_4 (red) versus Cl in injectate over time, based on Hawai'i State Department of Health records. The record is broken into four time increments: 1995 (crosses); 1998–2000 (triangles); 2001–07 (diamonds); and 2008–14 (pluses). Filled circles show composition of our injectate sample on April 30, 2014. Solid and dashed lines are seawater dilution lines for Na and SO_4, respectively.

solubility effects discussed above, but is nevertheless similar in composition to the HDOH data from the last six years.

The stable chemical composition of the injectate during the past six years provides a straightforward test for a component of reservoir fluid in the groundwater, specifically by searching for any trend in groundwater chemistry toward the injectate composition. We conduct the test using a series of plots that have the Cl on the x-axis and show dilution lines that would result from mixing a saline fluid (like seawater or injectate) with pure water. The properties and benefits of such plots were discussed in detail by Janik and others (1994). Using pure-water as an end member means that the dilution lines are independent of actual groundwater chemistry, helping to focus on the processes responsible for deviations of any particular groundwater from the dilution lines: for example, mineral solution reactions.

Groundwater Chemistry

Groundwater chemistry is plotted at different salinity scales, with figure 8 emphasizing results from springs and figure 9 focused on the less-saline groundwater wells. Seawater, with 19,000 mg/L Cl, exceeds the range of the x-axis but is represented by a dilution line on all plots. For consistency with Janik and others (1994), we use the composition of seawater from Hem (1985). When the injectate value exceeds the range of the axes, an injectate dilution line is shown based on sample PG14-13.

The six species used in these plots (figs. 8 and 9) were chosen for their contrasting behaviors in geothermal systems. In general, Na behaves as a conservative species that, like Cl, primarily reflects source waters; K and B have additional mineral sources and tend to become enriched in water as temperature increases; Mg partitions out of solution into

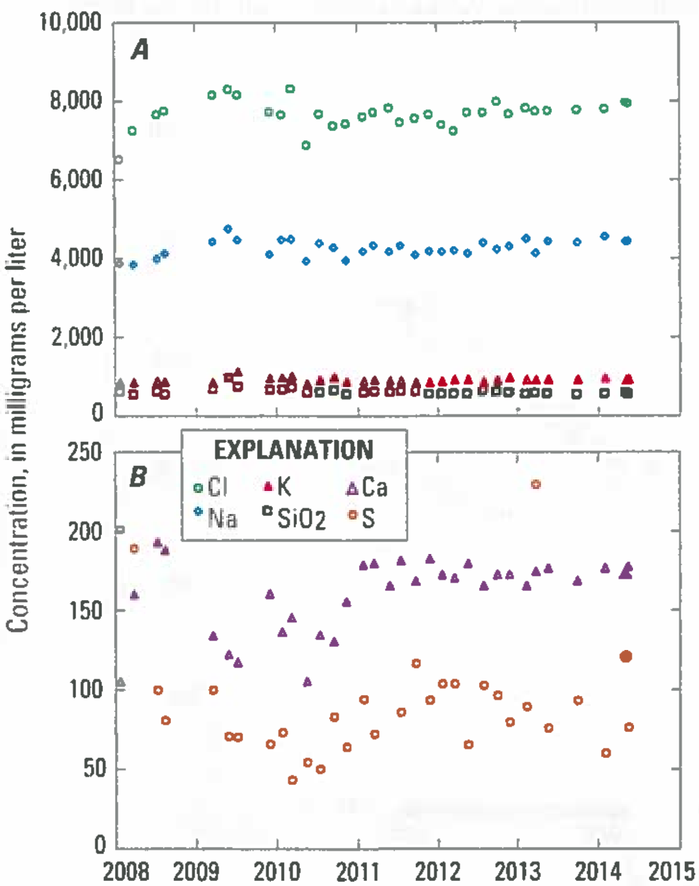

Figure 6. Concentration (in mg/L) of several major chemical species in the injectate over time, based on Hawai'i State Department of Health records (open symbols). Filled symbols show concentrations of the same species in our injectate sample of April 30, 2014. *A*) Na (diamonds), K (red triangles), Cl (green circles), SiO_2 (squares); *B*) Ca (purple triangles), S (brown circles) which represent total sulfate and reduced sulfur as S.

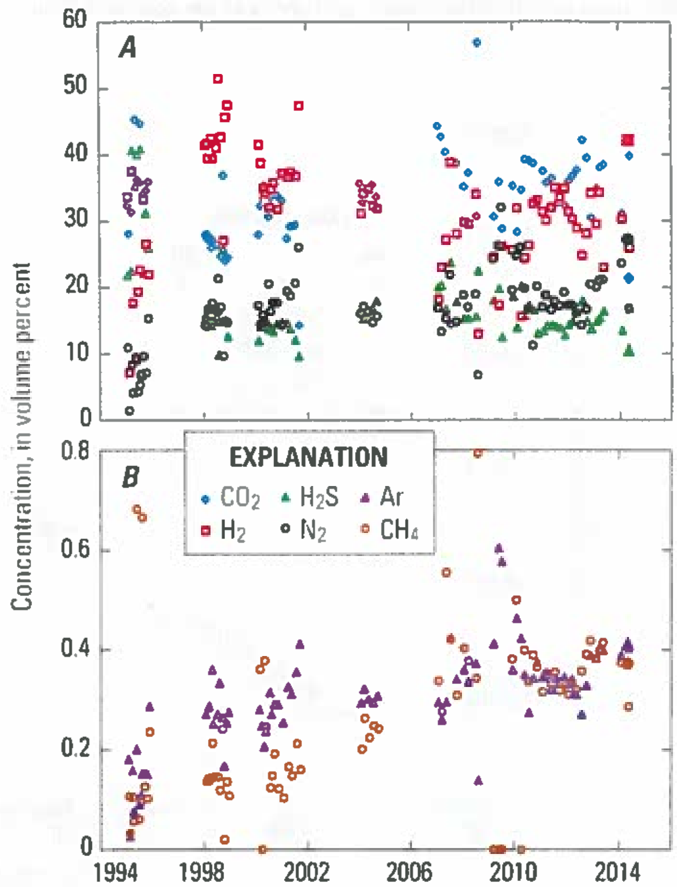

Figure 7. Concentration (in volume percent) of gas species (other than pentane) in the noncondensable gas line over time, based on Hawai'i State Department of Health records for 1995, 1998, 2000, 2001, 2004, and 2007-14 (open symbols). Filled symbols show concentrations of the same species in our injectate sample of April 30, 2014. *A*) CO_2 (diamonds), H_2 (squares), H_2S (green triangles), N_2 (black circles); *B*) Ar (purple triangles), CH_4 (brown circles).

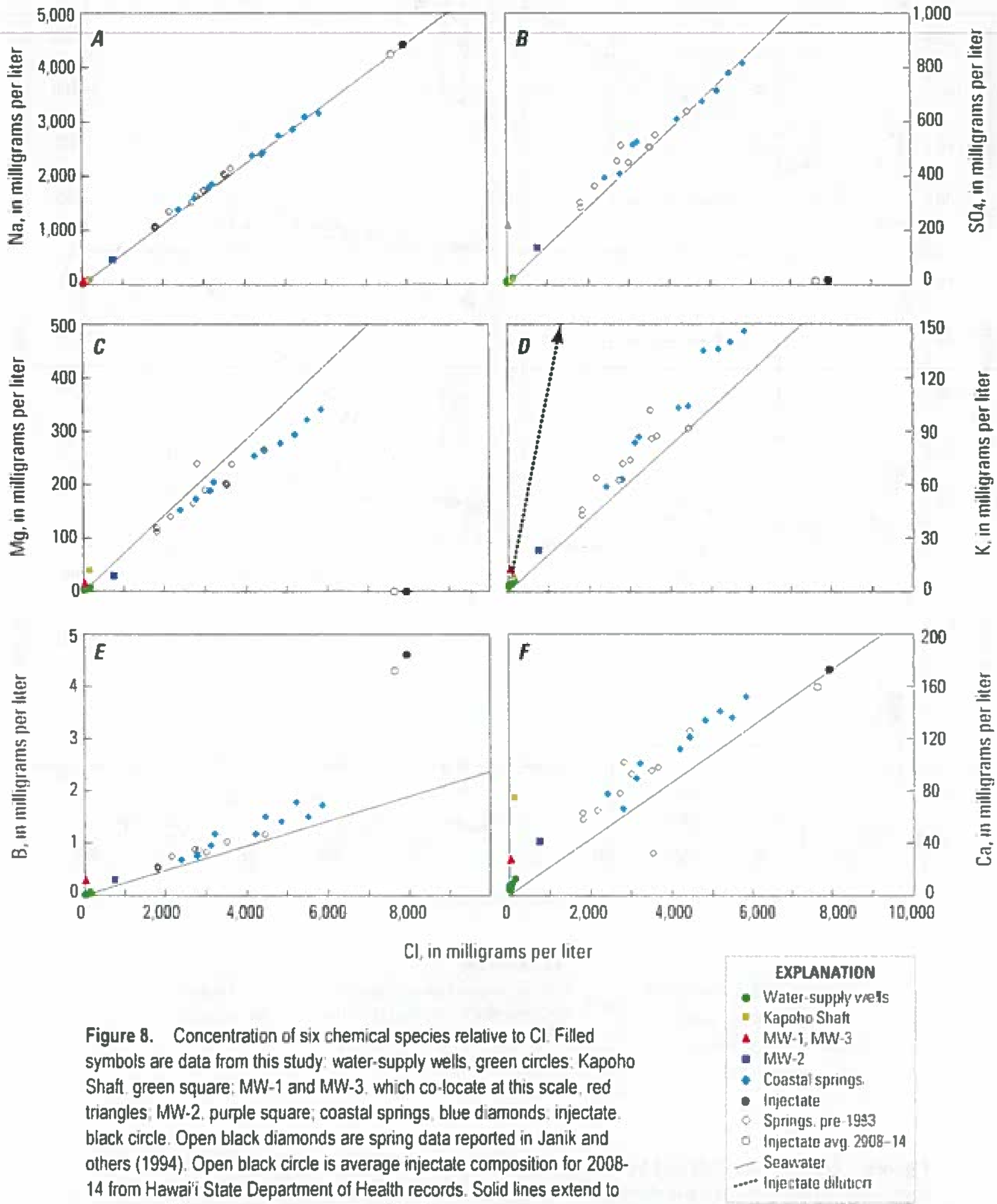

Figure 8. Concentration of six chemical species relative to Cl. Filled symbols are data from this study: water-supply wells, green circles; Kapoho Shaft, green square; MW-1 and MW-3, which co-locate at this scale, red triangles; MW-2, purple square; coastal springs, blue diamonds; injectate, black circle. Open black diamonds are spring data reported in Janik and others (1994). Open black circle is average injectate composition for 2008-14 from Hawai'i State Department of Health records. Solid lines extend to the composition of seawater at 19,000 mg/L Cl; dashed arrow in *D* extends to the composition of our injectate sample (893 mg/L K).

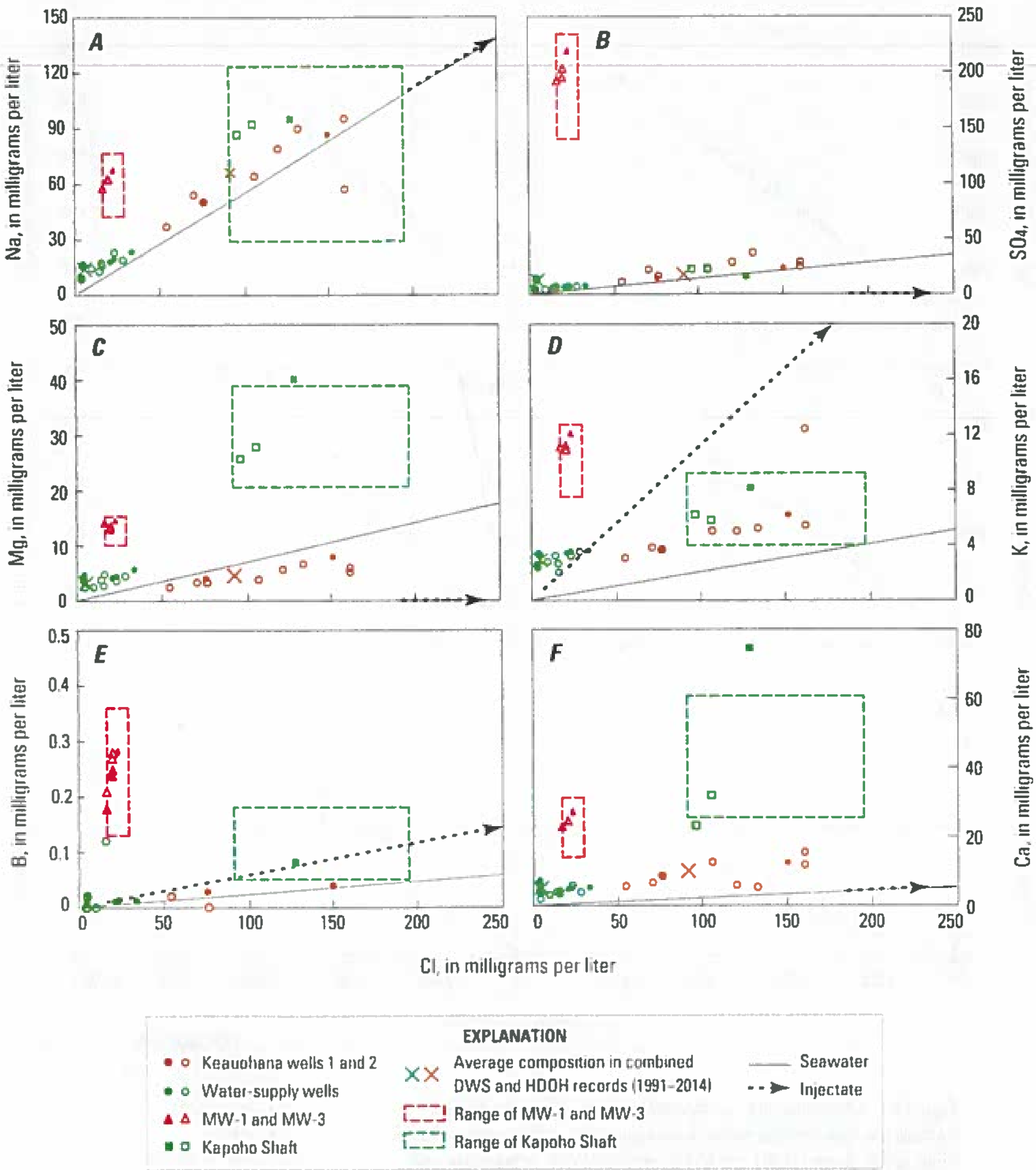

Figure 9. Expanded view of figure 8 highlighting results from particular wells. Filled symbols are data from this study, open symbols from Janik and others (1994). Keauohana wells 1 and 2, brown circles; all other active water-supply wells in table 1, green circles; MW-1 and MW-3, red triangles; Kapoho Shaft, green square. Large X's show average composition in combined County Department of Water Supply and Hawai'i State Department of Health (HDOH) records (1991-2014) for species analyzed at least five times. Keauohana #1 and #2, brown; Keonepoko Nui #1 and #2, and Pāhoa #2, green. Range of values for MW-1 and MW-3 from HDOH records during 1991-2014, red boxes; range for Kapoho Shaft from HDOH records during 1991-94, green boxes. Solid lines extend to the composition of seawater at 19,000 mg/L Cl; dashed arrows extend to the composition of our injectate sample.

mineral phases as temperature increases, as does SO_4, which can also be reduced to sulfide; Ca is typically dissolved from minerals at low temperature but can also be soluble at high temperature, depending on reservoir conditions. These contrasting behaviors are clearly reflected in figure 8. The injectate point lies on the seawater dilution line in the Na and Ca plots, and thus neither element can be used to distinguish reservoir fluid input from seawater input. The injectate plots above the line in the K and B plots, and well below the line and near the x-axis in the Mg and SO_4 plots.

Springs

The new spring data (fig. 8) extend to slightly higher concentrations than the data of Janik and others (1994). We found the salinity of these ponded springs to vary from point to point within the pool (based on field-measured specific conductance), and the difference in concentration ranges could reflect in part the exact sampling location. Temporal variation in salinity with tidal conditions has also been noted. Janik and others (1994) sampled at low tide, whereas we collected samples at various tidal conditions and made an effort to cover a broad salinity range. Regardless, the overlap in the datasets is large and, most importantly, the new and old data fall on essentially the same trend lines. Thus, the main conditions controlling the chemistry of these springs appear to be unchanged over time.

Janik and others (1994) proposed that the springs contain a component of heated seawater from a source region with a temperature near 165 °C. The actual salinity and temperature of this component are somewhat poorly constrained, because they depend, in part, on large extrapolations of trends like those in figure 8. Nevertheless, all trend lines radiate from a dilute end-member resembling the well waters toward a saline end-member with thermal characteristics, such as Mg depletion and K enrichment, relative to the starting seawater composition. The thermal, saline end-member is thus variably diluted by cold groundwater during underground flow to the springs.

Sorey and Colvard (1994) proposed that the source area for the thermal end-member is near the rift zone in a "conductive halo" around the commercially produced reservoir, where heated seawater can buoyantly rise through the overlying groundwater. They cite geophysical evidence (Kauahikaua, 1993) for outflow of saline thermal groundwater from the rift zone to the coast. Sorey and Colvard (1994) and Janik and others (1994) note that thermal saline water with similar characteristics was encountered in wells between the rift zone and the coast (for example, Malama-Ki and Allison).

None of the spring trend lines deviate far from the seawater dilution lines (fig. 8), but the Mg, B, and K trends fall toward the injectate side and could be consistent with a small admixture of reservoir fluid in the thermal, saline end-member. However, best-fit lines through the spring data (new and old) yield different mixing ratios: 17 percent reservoir fluid for Mg, 13 percent for B, and 5.6 percent for K. Furthermore, the SO_4 data show no indication of reservoir fluid, nor do the Ca data which, apart from one outlier in the older dataset that is likely spurious, plot on a trend parallel to the seawater and injectate dilution lines. The thermal end-member is apparently richer in Ca (relative to Cl) than both seawater and the PGV reservoir fluid. The major-ion chemistry data are not consistent with significant leakage of reservoir fluid into this large groundwater system. The concept of a conductively heated zone at a temperature above 60 °C, where Mg depletion typically begins (Seyfried and Bischoff, 1979; Sorey and Colvard, 1994), possibly as hot as 165 °C, is consistent with our data.

Two more points about the springs should be made. Their location within or just above the tidal zone exposes them to direct seawater dilution, which is likely the reason that Janik and others (1994) sampled at low tide. However, trends in the Mg and K data actually deviate further from the seawater dilution line with increasing Cl concentration, so that direct seawater dilution is not apparent in the data. Groundwater flow modeling presented by Imada (1984) and discussed by Sorey and Colvard (1994) implies that abundant rainfall and infiltration in the Puna area would rapidly dilute and erase evidence of geothermal contamination during groundwater flow from the rift toward the coast. However, if the springs do not mix with cold seawater at the coast, their Cl concentrations indicate that they still contain 10–30 percent of the heated seawater end-member (Cl ~ 19,000 mg/L). The corresponding 70–90 percent dilution by dilute groundwater during flow to the coast would not be so great as to completely erase contaminant signatures caused by leakage of reservoir fluids into the "conductive halo".

Groundwater Wells

Lower concentration ranges are plotted on figure 9 to focus on the well chemistry. Dilution lines in all plots point to the composition of seawater and injectate, which plot far offscale. The active groundwater supply wells are plotted in two groups that distinguish the Keauohana wells from the other, more dilute wells. The results from our samples follow the same trends as the data of Janik and others (1994) except for a few outliers in the older data that are likely spurious. Monitoring records for several public wells are available from the State HDOH and (or) the County DWS, and these records fill the gap between our 2014 sampling and the pre-1994 data reported by Janik and others (1994). The number of analyses for each well and each species varies greatly; for example, some wells have been analyzed frequently for Na but never for B. For this study, we combined the records from the Keonepoko Nui and Pāhoa wells and calculated average concentrations for each species of interest (fig. 9). We also combined the records of the two Keauohana wells between 1991and 2014 and denote the average concentrations on figure 9. Averages were not calculated unless the number of analyses in the combined HDOH and DWS records exceeded five.

The averages that were calculated plot within the respective groups of well data from our study and that of Janik and others (1994).

For species other than Mg, data trends fall along, or parallel to, the seawater dilution lines. Seawater is thus an important source of dissolved species even in this low concentration range. Additional Na, K, Mg, and Ca can be derived from mineral dissolution in the aquifer, so that the wells generally plot above the seawater dilution lines. The Mg data for the Keauohana wells follow a trend subparallel to the injectate dilution line. These wells have long been considered to have a slight geothermal character (Iovenitti, 1990; Janik and others, 1994), but the trends in SO_4, K, and B clearly differ from injectate-dilution trends, and therefore no component of reservoir fluid can be discerned. The geothermal component in the Keauohana wells could be similar to the conductively heated seawater in the coastal springs, slightly depleted in Mg. Regardless, the older data from Janik and others (1994) include samples from the mid-1970s, prior to geothermal development, and the similarity over 40 years argues against any substantial impact on chemistry from PGV operations.

The Kapoho Shaft was originally used as a public-supply well but has not been pumped in decades. The small portable pump we used to bring up water was not capable of fully purging water from the well and bringing in fresh groundwater from the local aquifer. Perhaps as a result of this, our sample differs somewhat from all previous analyses, but shows a general similarity in that it is rich in Mg, Ca, and HCO_3 (table 2; fig. 9). Janik and others (1994) attribute these characteristics to mineral dissolution by dissolved CO_2. The B concentration in this well plots on the injectate-dilution line, but the Mg, Ca, and SO_4 concentrations provide no evidence for influence of PGV injectate.

Thermal Wells

The new data for MW-1 and MW-3 are compositionally similar to the older data from Janik and others (1994), but slightly higher in several constituents (fig. 9). The data fall within the range observed in ~75 samples collected from these two adjacent wells between 1991 and 2014 as part of the ongoing HDOH water monitoring program.

The unique chemistry of the water in these two wells is attributed to absorption of H_2S gas from an underlying steam zone, followed by oxidation to sulfuric acid, which dissolves cations from aquifer minerals (Janik and others, 1994; Sorey and Colvard, 1994). Thus, the major anion is sulfate and cations are substantially elevated relative to the seawater dilution line. Steam absorption also explains the high concentrations of B, which becomes volatile at high temperatures. Variations in the relative proportions of rainfall recharge and steam upflow likely cause some of the chemical variability over time but the absence of obvious long-term trends in water composition (fig. 9) suggests that geothermal operations are not inducing major changes to these groundwaters.

Well MW-2, plotted in figure 8, shows a greater seawater influence than MW-1 and MW-3, but also a clear depletion in Mg and a small enrichment in SO_4 relative to the seawater dilution lines. Some small component of H_2S-laden steam may explain the SO_4 enrichment, but this well is also located near the former HGP-A site, where SO_4 from gas abatement procedures was allowed to infiltrate during the 1980s (D.M. Thomas, University of Hawaii, Mānoa, personal commun., 2015). The water chemistry is generally consistent with conductively heated seawater diluted by local groundwater. The long-term HDOH monitoring record (fig.10) shows a high degree of chemical variability at MW-2 that must reflect in part frequent changes in the mixing proportions of the source fluids. The chemistry of our sample is within the range of variability in the monitoring data. This well is equipped with a small gas-lift pump, and the low flow rate we used for sampling probably explains why our sample is several degrees cooler than is typical of the recent monitoring data. Despite this issue, the HDOH record shows clear long-term trends of declining temperature and increasing Mg concentration that are independent of source mixing and likely linked, given that Mg is more easily retained in solution at lower temperatures. These long-term trends may be an indirect impact of geothermal development, in that conductive heat transfer might decline with long-term extraction of heat from the reservoir, but any linkage to geothermal operations is speculative. A possible link between changes in temperature and chemistry in 1991–92, and a steam blowout at well KS-8 was found unconvincing by Sorey and Colvard (1994), and the amplitude of variations in the record since that time (fig. 10) make such a link even less likely.

Other thermal wells exist in the Puna area but are not pumped, and were therefore not suitable for our sampling protocol. Two of these wells, Malama-Ki and TH-3, were included in the HDOH monitoring program until the year 2000, and the resulting data are shown in figure 11 along with data from Janik and others (1994). These wells, and the thermal Allison well, show a high degree of temporal variability, as seen in the large spread in data in every plot (fig. 11). Nevertheless, apart from a few outlying points, the data do show some clustering and trends.

The trend along the seawater-dilution line is fairly clear for Na and Cl. In contrast to the coastal springs, the thermal wells show depletion in both Mg and SO_4 relative to seawater dilution lines—a noted characteristic of the injectate. However, the trends through the data miss the injectate and indicate mixing between two source components, dilute local groundwater and seawater that has been extensively hydrothermally altered, greatly reducing its Mg and SO_4 concentrations. A three-component mixture that includes an injectate component could also be consistent with the data. However, the HDOH monitoring data for Malama-Ki and TH-3 plot on and around the older data from Janik and others (1994), which includes analyses from the 1970s in Kroopnick and others (1978), suggesting that these wells were not changing in response to geothermal operations through the year 2000.

Stable Isotopes

The isotopic composition of groundwaters in the Puna area was investigated in the 1970s by McMurtry and others (1977). Scholl and others (1996) established an extensive network of precipitation collectors in the region in the early 1990s and found that rainfall on the southern part of the island plotted on a line with formula $\delta D = 8.0\ \delta^{18}O + 12$. They defined this formula as the local meteoric water line (LMWL) and noted that it matched the earlier findings of McMurtry and others (1977).

Scholl and others (1995), in their appendix 2, reported isotopic values for many of the springs and wells sampled in our study and averaged the values from 2-3 different samples of each feature with the earlier data from McMurtry and others (1977). In figure 12*A*, the isotopic data for our 2014 samples is compared with that in appendix 2 of Scholl and others (1995) for wells and springs in the Puna area. The two datasets show an overall similarity despite the fact that some sampling locations differ. However, the new spring data are clearly shifted upward (toward less negative δD values) relative to the older data. The springs puzzlingly plot on or near the LMWL of Scholl and others (1995), even though they contain a component of heated seawater. Closer inspection reveals that the new data from the groundwater wells plot slightly to the left of the LMWL; that is, the change in isotopic composition is not restricted to the springs.

The isotopic composition of precipitation, and hence groundwater, in a given area can shift over time in response to changing climatic conditions. A change in storm tracks or precipitation patterns that persists for some months could conceivably cause a temporary shift in the LMWL in a setting like the Puna area, where recharge and groundwater velocities are high. The 2014 data for supply and monitoring wells adhere to a line with a formula $\delta D = 7.86\ \delta^{18}O + 13.2$ (fig. 12*B*). With our limited number of sampling points, we cannot define a new LMWL, but we take our line of best fit to reasonably characterize Puna groundwater in 2014. Relative to this line, the springs plot in the direction of seawater as expected. Isotope and Cl data combine (figs. 12*C*,*D*) to

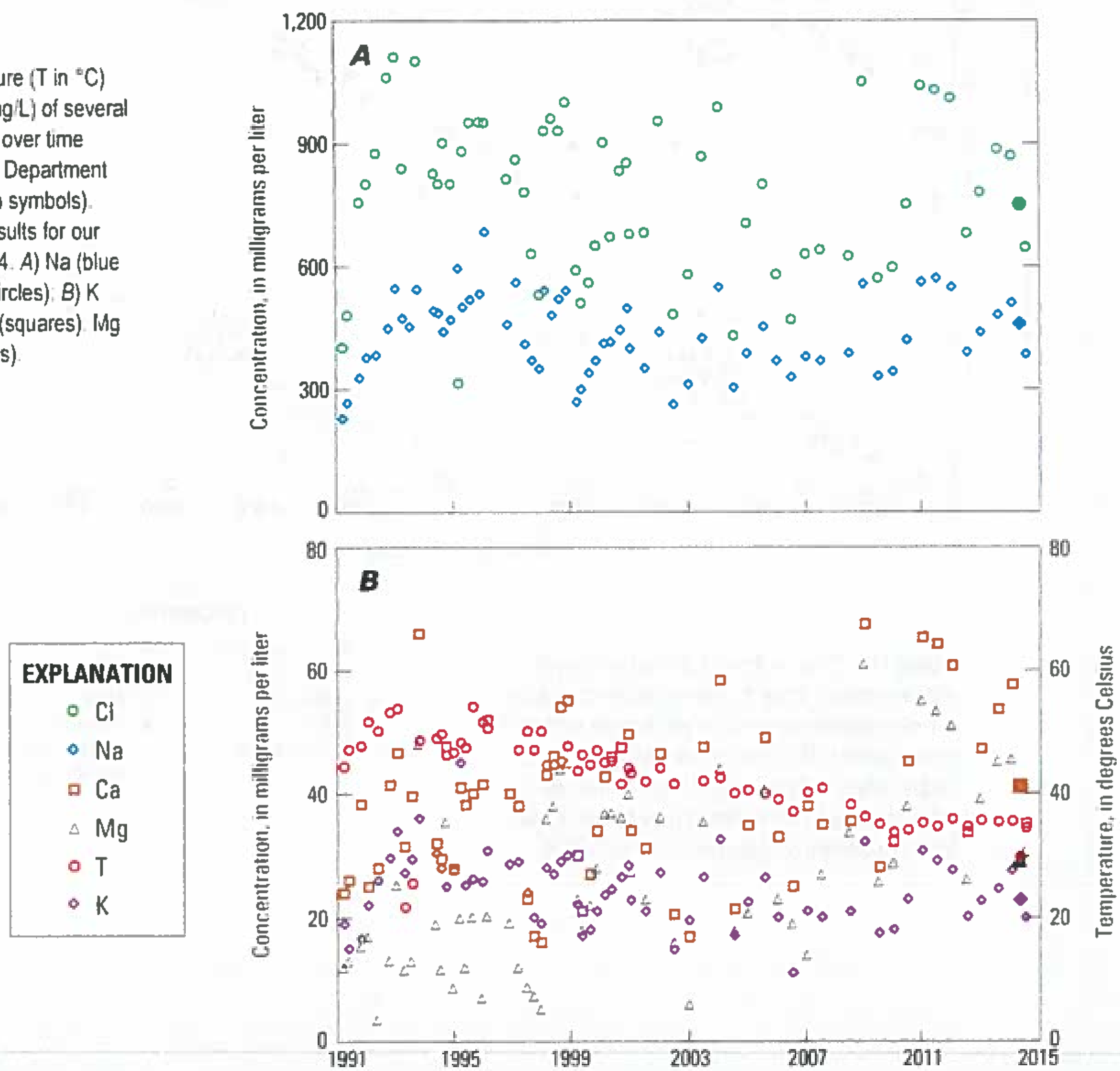

Figure 10. Temperature (T in °C) and concentration (in mg/L) of several major species in MW-2 over time based on Hawai'i State Department of Health records (open symbols). Filled symbols show results for our sample of April 30, 2014. *A*) Na (blue diamonds), Cl (green circles). *B*) K (purple diamonds), Ca (squares), Mg (triangles), T (red circles).

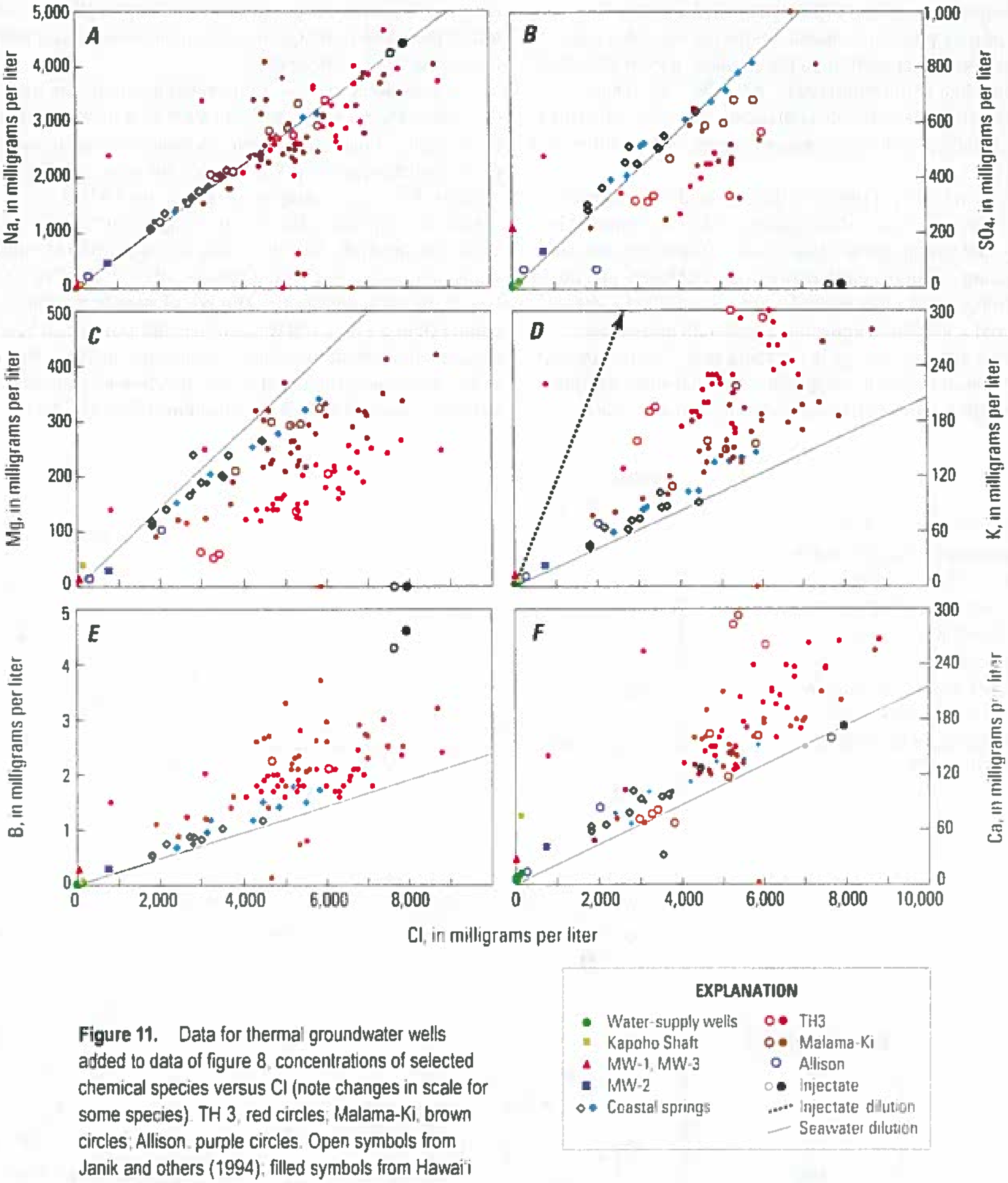

Figure 11. Data for thermal groundwater wells added to data of figure 8, concentrations of selected chemical species versus Cl (note changes in scale for some species). TH 3, red circles; Malama-Ki, brown circles; Allison, purple circles. Open symbols from Janik and others (1994); filled symbols from Hawai'i State Department of Health records 1991–2000.

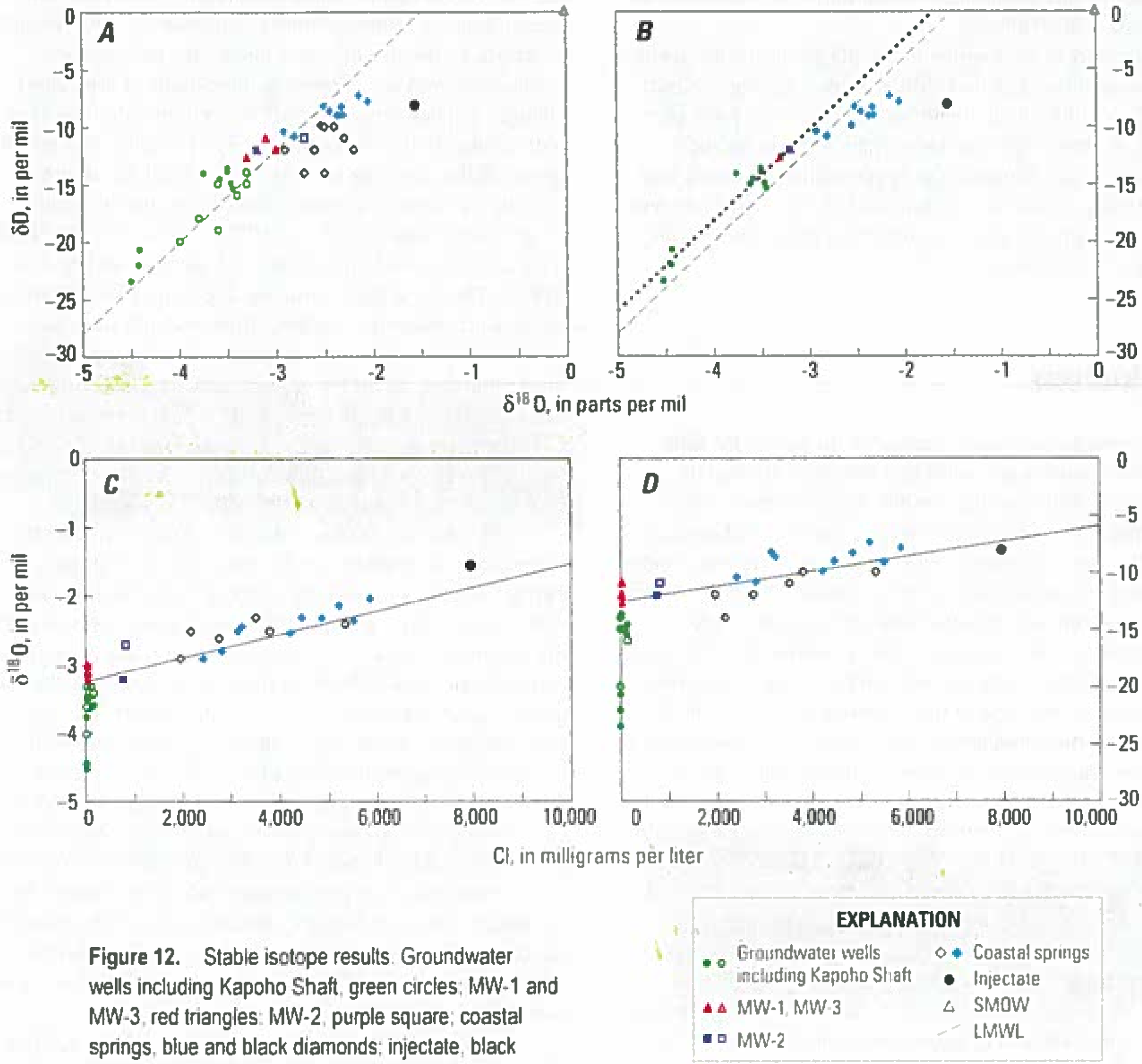

Figure 12. Stable isotope results. Groundwater wells including Kapoho Shaft, green circles; MW-1 and MW-3, red triangles; MW-2, purple square; coastal springs, blue and black diamonds; injectate, black circle. Results from this study are shown as filled symbols; open symbols are data reported in appendix 2 of Scholl and others (1995). Open black triangle represents standard mean ocean water (SMOW). *A*) δD versus $\delta^{18}O$ (in per mil) with local meteoric water line (LMWL) of Scholl and others (1995). *B*) 2014 results only with regression line for wells (dotted line). *C*) $\delta^{18}O$ (in per mil) versus Cl (in mg/L). *D*) δD (in per mil) versus Cl (in mg/L). Solid black line in *C* and *D* extends from the monitoring wells to the composition of seawater at 19,000 mg/L Cl.

support the inference that the springs are mixtures of heated seawater and local groundwater. This groundwater appears to be isotopically similar to that in the monitoring wells near PGV. An injectate component would not be recognizable on the basis of stable isotopes.

Some part of the change in the δD values of the springs over time, and the apparent shift to higher average salinity (fig. 12*D*), could reflect changing conditions at depth (for example, in the conductive halo), which might include boiling and steam formation as hypothesized by Janik and others (1994). However, explanations for the small observed changes, and any linkage to geothermal development, are speculative at this point.

Conclusions

In response to concerns raised in the report by Adler (2013), our groundwater sampling program focused on water-supply wells and on thermal springs in the coastal environment. We were able to access, sample, and analyze nearly all of our intended targets for pentane and isopropanol, two tracer compounds that enter the fluid at the PGV power plant and are injected into the deep geothermal reservoir. Isopropanol was not detected in any groundwaters. Traces of pentane were detected in one of the PGV monitoring wells (MW-2) and in one sample from Keonepoko Nui well #2. Replicate samples indicate that the "detect" at Keonepoko Nui is spurious. The pentane in MW-2 could be linked to PGV injectate, but alkane abundances are consistent with a natural source, such as buried organic matter that is degraded at the warm aquifer temperatures. Thus, neither tracer provided meaningful evidence for contamination of groundwater by PGV fluids, although the recent onset of isopropanol use (September 2013) would probably preclude its migration to sites far from the power plant prior to our sampling. Pentane was found to degrade in the hot H_2S-rich geothermal fluids, and degradation of isopropanol cannot be ruled out. Degradation complicates, but does not exclude, the use of these tracers to detect leakage of reservoir fluids into shallow groundwater. They would certainly be of great value for local detection of direct leakage of injectate into groundwater due to well casing failure, for example.

Previous studies of groundwater chemistry in the Puna area (for example, Sorey and Colvard, 1994; Janik and others, 1994) have invoked conductive heat flow from the geothermal reservoir into saline groundwater that is consequently altered from its original seawater composition. The postulated hot saline groundwater is diluted by shallow groundwater before emerging at the coastal springs or, after great dilution, being pumped from the Keauohana wells. Our new water chemistry data fit this general model.

The Puna area hydrology is characterized by rapid infiltration of rainfall, a thin freshwater lens, and convective instabilities near the rift zone (Thomas, 1987; Ingebritsen and Scholl, 1993). These and other factors lead to temporal variations in mixing between dilute and saline end-member fluids and are likely responsible for the short-term compositional variability that is a well-known feature of many Puna groundwaters. This variability complicates the use of water chemistry in assessing geothermal impacts. However, long-term or abnormal changes in chemistry can still be recognized at features with a long history of sampling. For instance, our results reveal higher average salinity and a small but distinct shift in the isotopic composition of the coastal springs from values measured in the 1970s–1990s. We also find a long-term drop in temperature and increase in Mg at well MW-2. These changes could be due in part to alteration of pressure gradients and heat flow at depth in response to geothermal development, but direct linkage would be hard to substantiate. Apart from these changes, the similarity between our results, the results from mandated monitoring over the previous 20 years, and results from samples from the 1970s–1990s imply that geothermal production has not had a significant impact on groundwater chemistry.

Our sampling protocol was developed for flowing wells or springs that discharge at the land surface. Sample coverage did not include any offshore vents of warm water, which exist in the area, and we point out that contaminant transport from the geothermal reservoir directly to such features could occur on timescales much different from those based on shallow groundwater velocities assumed in this report. We were also unable to sample any of the hot groundwater wells that lack pumps and are down-gradient from PGV. We reviewed the water chemistry data from HDOH records for samples collected downhole through the year 2000 at Malama-Ki and TH-3. These data do not show obvious evidence of long-term trends related to geothermal production, but do show significant scatter that might obscure such trends. Samples suitable for pentane and isopropanol analysis could be obtained from such wells, but temporary installation of pumps would likely be required.

If any immediate follow-up to our study is desired, we recommend that it focus on the hot groundwater wells, using pumps to completely flush the wellbores, and on offshore vents of warm water, using underwater sampling techniques as necessary. Given that obvious geothermal impacts were not observed in the groundwaters we studied, we suggest only minor changes to the existing onshore monitoring program: (1) the analytical protocol for the Keauohana and Pāhoa public-supply wells near PGV should include isopropanol on at least an annual basis; (2) a sampling program should be established for a representative group of coastal springs to ensure that comprehensive chemical analyses are performed annually or at least every few years (these analyses should include isopropanol and perhaps pentane); (3) isopropanol analyses should be performed on the monitoring wells (MW-1 through MW-3) at least annually, and more frequently if casing pressures in the injection well show any indication of leakage.

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APPENDIX B

PUNA GEOTHERMAL VENTURE

PROGRAM FOR MECHANICAL INTEGRITY TESTING AND MONITORING OF INJECTION WELLS

1. INTRODUCITON

1.1 Background

Pursuant to Underground Injection Control (UIC) Permit No. H1596002, the U.S. Environmental Protection Agency requires that Puna Geothermal Venture (PGV) comply with this Testing and Monitoring Program (TMP) for injection wells. Monitoring and testing provisions in this TMP are similar in most respects to those in the "Casing Monitoring Program," April 26, 1993 version, which is reference by title in PGV's current UIC Permit No. UH-1529. It is anticipated that this TMP will be approved and adopted as a single replacement for the current two documents, using the more stringent version of each. The purpose of this change is to consolidate the existing documents for a clearer, non-conflicting approach to accomplish the goal of protecting the groundwater aquifer under the PGV project site which is considered to be a USDW. The principle changes in the monitoring and testing procedures are as follows:

- As described in Section 3.1 of this TMP for wells in injection service, the annulus nitrogen pressure will be maintained to keep the nitrogen/water interface at a depth of at least 2000 feet. This depth ensures injection fluid will remain well below the USDW at the PGV Facility of around 700 feet.
- In accordance with Section 3.2.1, the annual casing pressure test of each well will be done by depressing the water level to 3000 feet with nitrogen while the well is on injection. Annulus pressure drop exceeding 10% in five hours will be considered indicative of a leak requiring diagnosis and repair.

1.2 Purpose

The purpose of this TMP is to specify the observations, tests, drilling operations and, if necessary, remedial actions required to insure that the mechanical integrity of injection well casing and cement is maintained through the drilling, testing, and operation of PGV wells. The cemented and hung casing strings that are used in the PGV wells are designed to prevent contamination of any underground source of drinking water (USDW) by injected fluids. Contamination of the USDW's might occur if the casing strings are breached due to corrosion or mechanical failure or if there is a failure of the cement to seal the casing/borehole annulus between the casing shoe and the lowermost USDW. The testing and monitoring program described below is designed to detect and diagnose a loss of mechanical integrity in the casing or cement. Remedial actions required to restore mechanical integrity are also described.

1.3 Scope

This TMP covers all injection wells on the 500 acre PGV site.

2. TESTING DURING DRILLING AND COMPLETION

2.1 Pressure Testing During Drilling

Each injection well is completed with three casing strings (not including the 30-inch conductor pipe) cemented to the surface (Figure 1). Upon completion of cementing each casing string and prior to drilling out the cement shoe, the casing will be pressure tested. The DLNR will be notified at least 24 hours before each test for the opportunity to witness it. The test will consist of pressurizing the casing with water or drilling mud to a specified test pressure and monitoring the pressure for 30 minutes with the well shut in. The minimum casing test pressure shall be up to 70% of the minimum internal yield pressure of the casing, provided that the test pressure shall not be less than the Maximum Authorized Injection Pressure (MAIP), nor greater than 2500 psig. In cases of new wells the MAIP must be a calculated projection, allowing for the possible conversion to injection. In cases where combination strings or liners are involved, the above test pressures shall apply to the lowest pressure-rated casing. The pressure drop during the 30 minute period shall not exceed 10% of the test pressure.

In the event of a pressure loss exceeding the above criterion, one or more of the following diagnostic methods will be used to locate the leak:

- Pressure Temperature log while injection
- Shut in Pressure Temperature surveys, (minimum of 2 surveys)
- Casing inspection logs with multi-arm caliper and/or magnetic inspection tools
- Pressure testing with a packer on drill pipe
- Other applicable methods

After identification of the point of leakage, a cement squeeze job will be performed and the casing retested. Results of each pressure test will be reported to the Department of Land and Natural Resources (DLNR) and the DOH.

After a successful pressure test of each casing string, drilling will proceed to a point at least one foot below the casing shoe and a pressure leak off test-off test shall be performed to test the integrity of the annular cement. Each test will be performed at a pressure approaching the fracturing pressure of the exposed formation as to not weaken the formation. If there is excessive leak-off, a squeeze cement job will be performed, the cement will be drilled out and the test will be retaken. Drilling will not proceed until an effective cement seal in the casing/borehole annulus above the shoe.

In some situations, such as the case where there is a natural formation permeability immediately below the casing shoe, it may not be practical to prove cement integrity with the pressure test described above. As an alternative shut in temperature surveys (Attachment 1) may be run or a Quad Neurtron Water flow log (Attachment 2) may be performed as two examples, or any additional BAT as determined by PGV.

2.2 Logs and Surveys During Injection Testing

Upon completion of drilling and prior to installation of the hangdown liner, a water injection test may be performed, if needed, to obtain a preliminary evaluation of the well. During such a test, one or more of the following logs or surveys may be run:

- Temperature, Pressure, Spinner (TPS) or Temperature, Pressure (T/P) logs through the open hole and cased intervals with the well on injection
- Shut-in T/P survey(s) before and/or after injection, , including drop-off pressure data (Attachment 3)
- Casing Inspection logs with and multi-arm caliper and or magnetic inspection tools
- Other BAT as determined by PGV

If any of these logs or surveys indicates a loss of mechanical integrity, the problem will be diagnosed and repair procedures will be performed in accordance with Section 2.3.

2.3 Casing Repair

Once a loss of mechanical integrity is identified and approximately located, casing repair procedures will be initiated. These procedures may include any or all of the following activities:

2.3.1

Shut in well and run magnetic and multi-arm casing inspection logging tools to locate the leak and to evaluate the casing condition.

2.3.2

Rig up workover rig on well. Run packer on drillpipe and pressure test to confirm suspected leaking interval.

2.3.3

Run a retrievable packer into well below the leaking interval. A sand spacer and cement plug can be set above the retrievable packer to insure a good seal. Execute the cement squeeze job to seal the casing leak or stop inter zonal flows behind casing.

2.3.4

Drill out cement past squeezed leaking interval and perform casing pressure test and other diagnostic tests as necessary to confirm success of the remedial work. If testing confirms the repair, drill out the cement above the packer and retrieve the packer. Move rig off the well and return the well to injection service.

2.3.5

In the event of major casing failure, a cemented liner may be installed through the damaged interval.

2.3.6

Prior to drilling out the liner shoe, the liner will be pressure tested as described in Section 2.1.

2.3.7

If mechanical integrity cannot be restored satisfactorily, the well will be plugged and abandoned.

3. MONITORING AND TESTING AFTER WELL IS PLACED INTO SERVICE

3.1 Continuous Monitoring During Routine Injection Operations.

During routine injection well operations, including brief periods when well(s) may be temporarily out of service, the following conditions will be maintained:

3.1.1

A continuous recording of the following parameters sill be maintained for each well:

- Injection wellhead pressure
- Annulus (Nitrogen) pressure
- Injection flow rate

These parameters shall be recorded on a graphical chart which shows their relationship to elapsed time. Plant operators will take daily readings at each well.

3.1.2

During routing injection the annulus between the cemented casing and the hang down liner will be pressurized with nitrogen, and the pressure will be monitored and recorded in accordance with 3.1 above. The annulus will be re-pressurized with nitrogen as necessary to maintain the nitrogen/water interface at a depth of 2000 feet KB (1975 feet below ground level) to keep injection fluids well below the USDW at PGV. Some loss of nitrogen is normal and occasional recharge will be required. If the rate of nitrogen pressure decline is such that it is impractical to maintain the required minimum pressure, it will be considered indicative of a leak requiring diagnosis and repair.

3.2 Annual Testing

Once annually, tests and surveys will be conducted to verify mechanical integrity of the hang down liner. These tests and surveys will be scheduled sequentially within the same time period. One or more shut in static pressure, temperature surveys will be run. Shut in time will be at least 12 hours or longer if necessary to obtain meaningful results. For any exceptions, PGV must request for approval in advance with a justification for the change. The casing and hang down liner will be tested for leaks by one of the following procedures:

3.2.1

Perform a pump-down test on the annulus between the hang down liner and the cemented casing. The test will be done with the well on injection at normal operation flow rate and wellhead pressure or higher. Nitrogen will be injected into the annulus to a pressure sufficient to depress the water level to a depth of at least 3000 feet and shut in. Surface pressure on the annulus and hang down liner will be monitored and recorded. Annulus pressure leak-off exceeding 10% in five hours will be considered indicative of a leak requiring diagnosis and repair. Analysis to qualify the rate of nitrogen pressure leak-off will include a correction for changes in wellhead pressure, temperature, and injection rate during the five hour test period, if applicable.

or

3.2.2

If the hang down liner is pulled, the casing may be pressure tested above a bridge plug or packer set near the shoe following the basic procedure outlined in Section 2.1. Integrity of the hang down liner may be verified by inspection on the surface, by a pressure test (with nitrogen) after it is run in the hole, or by a TPS log with the well on injection.

Integrity of the cement (External Mechanical Integrity) will be checked during each workover by one of the following procedures:

3.2.3

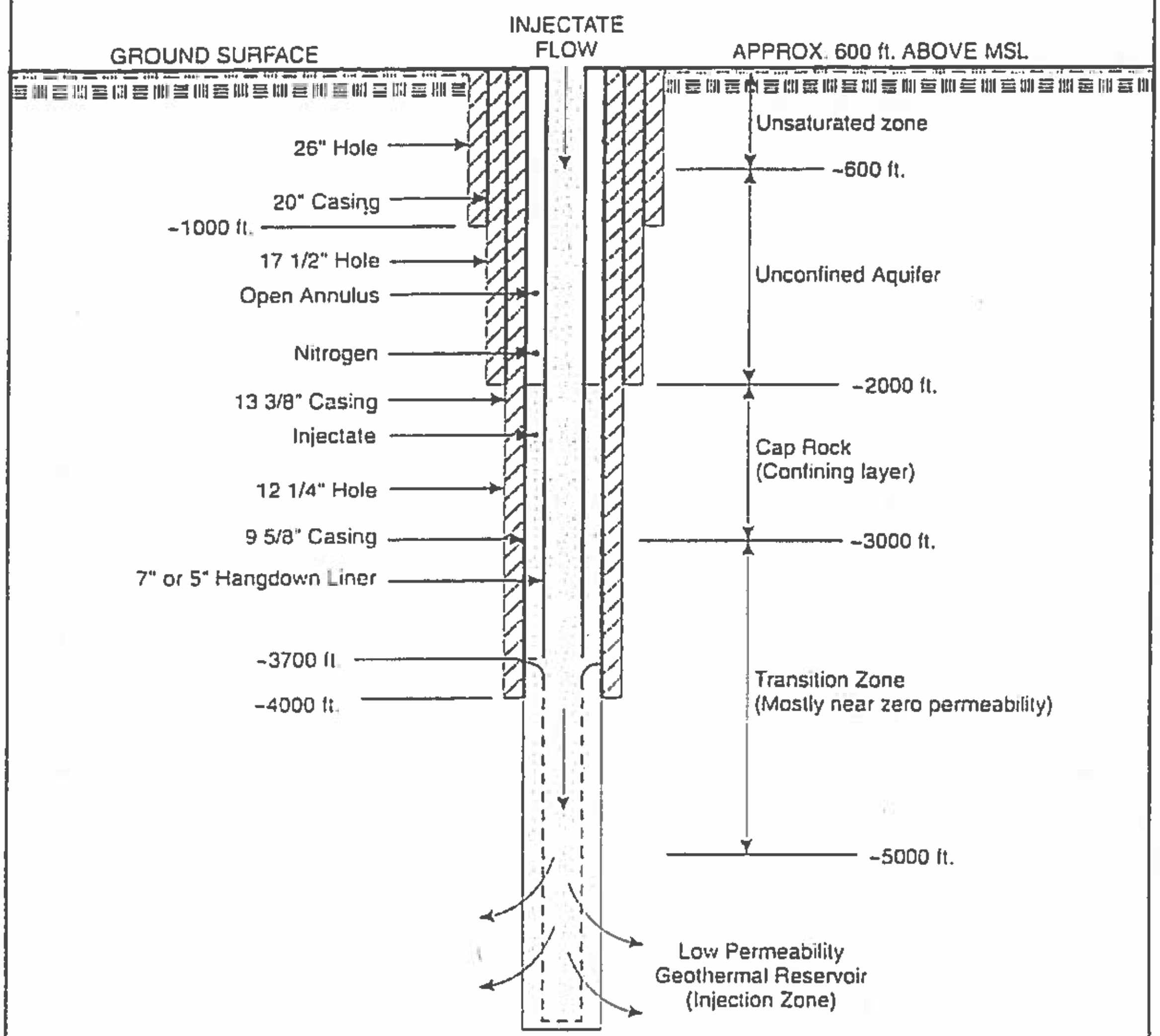
One or more shut in static pressure, temperature surveys will be run. Shut in time will be at least 12 hours or longer if necessary to obtain meaningful results.

3.2.4

Other logs or surveys may be run, at the discretion of PGV, if static temperature surveys are not definitive.

3.3

Restoration of Mechanical Integrity or Abandonment. In the event the diagnostic procedures indicate a loss of mechanical integrity, remedial or abandonment procedures will be carried out a specified in Section 2.3.



SCALE: 1" = 1000 ft.

ecology and environment, inc. International Specialists in the Environment Seattle, Washington	PUNA GEOTHERMAL VENTURE	INJECTION WELL DESIGN AND GENERAL HYDROGEOLOGIC CROSS-SECTION IN THE VICINITY OF PGV's INJECTION WELLS

Drawn By	Date	TDD/Job No.	Dwg. No
MTE	7-17-96		[illegible]

Quad Physics Principles (Attachment 2)

The Quad is a four detector Neutron tool that measures reservoir responses due to Neutron bombardment. Two detectors are Thermal Neutron detectors, but of critical importance, two are Neutron-Gamma detectors.

When bombarded with high energy Neutrons, reservoir rock and fluids not only create Thermal Neutrons, but also create numerous Gamma Rays (N-Gammas) from both Neutron capture and activation.

The Quad Neutron-Gamma detectors measure these responses, and the combination of Thermal Neutron and Neutron-Gamma measurements are very powerful in differentiating many reservoir parameters.

The dilemma for all downhole tool designs is to, not only measure environmental responses including reservoir affects, but to understand and separate/correct all the interfering responses into meaningful singular reservoir characteristics.

Untangling the information hidden in the combination of Quad detector responses requires several techniques, including detector balancing, statistical normalization, and Quad Litho Log Overlay (QLO) methods. Without these techniques, the responses cannot be turned into singular reservoir parameters, and that is key to why the Quad works where many other tools, such as those that apply spectral techniques and/or decay techniques, may not.

To demonstrate the point, consider this simple example: Let's measure saturation with a sigma device. Because sigma is a discrete measurement, saturation determination is critically dependent on somehow gaining an accurate current porosity and then further correcting sigma for a host of other estimated environmental effects, all with variable, and possibly dramatic effect. Quite distinctly, the Quad uses the difference between a porosity log created from Thermal Neutrons and another created from Neutron Gamma's. Because these two measurements were generated from the same tool, with the same statistical variability, on the same pass, with balanced and complementary detectors, the difference is chiefly based on salinity, while almost all other effects are automatically normalized and usually do not need to be considered; both elegant and powerful.

KS-13 ML-1
Water Flow Log using Quad-Neutron Tool as a Formation Integrity Test

Quad Neutron logs were run on KS-13 to determine where water was flowing too outside of the milled window (4369 ft to 4397 ft).
The logging methodology is based on the chlorine sensitivity of neutron logs. To determine where the water is travelling, a base neutron pass was done after filling the well with two hole volumes of fresh water. It is assumed that one hole volume of fresh water would exist outside the casing in the path that the water is travelling. Once the base Quad Neutron pass was completed, two hole volumes of salt water was added from the surface. Assumption being that one hole volume of salt water would replace the one hole volume of fresh water outside the casing in the pat that the water is travelling the other hole volume would displace the fresh water in the casing. A second Quad Neutron log was run immediately after the salt water was added.
The Quad Neutron tool has both Neutron Gamma and Neutron Neutron detectors. Salt water will cause the counts on the Neutron Gamma detectors to increase while the counts on the Neutron Neutron will decrease. to easily see changes, the pass done in Salt Water (SW) is overlaid with the base pass done in Fresh Water (FW). The overlay will remove the borehole fluid change and any remaining differential will be due to fluid changes behind pipe. The Neutron Gamma counts on the SW pass were shifted by ~370 counts per second (cps) while the Neutron Neutron counts on the SW pass were increased by ~1960 cps.
When reviewing the log responses, we need to remember that salt water that has replaced fresh water will show up as an increase on the Neutron Gamma counts and a decrease on the Neutron Neutron counts, denoted as SNG and SNN respectively. As can be seen on the log there is no difference between the FW and SW passes in and around the window. The only scenario that fits the result is that the fluid traveled down near well bore. The reason near well bore is that any significant volume of water, travelling radially out from the window, would have been detected. Any volume travelling up behind casing would have had to eventually go radial away from the borehole and again would have been detected. Conclusion - fluids traveled down near well bore.
Looking at other aspects of the log, there is a notable change at 2748 ft. Both SNN_SW and SNG_SW increased relative to the fresh water baseline. Since both increased, salt water can be ruled out. It is suspected that an air bubble was trapped or travelling at this depth which would increase both detector count rates. Included on the log is a Quad Clay curve, a relative bulk density curve and a lithology map. The Quad Clay curve is computed primarily from the Neutron Gamma ratio relationship and is presented on the far right of the log. The computation is sensitive to Thermal Neutron nuclides, with Aluminum, Manganese and Magnesium being the more likely suspects downhole. The clay curve is used as an input for the lithology map. Since our experience with Hawaiian formations is very limited, we labelled the clay influence as Magnesium based on some articles we found on Hawaiian formations. The Relative Bulk Density porosity curve is presented in the same track as the SNN curves. An increase in values for this curve represents an increase in bulk density porosity which is equivalent to a decrease in bulk density. The curve is computed by comparing the thermal neutron field strength to the neutron gamma field strength. The curve is relative because a zero point is chosen to represent the normal density relationship, from which all variances are compared to. The Relative Bulk

Density porosity curve is also used for the lithology map to highlight High Bulk Density Materials in the lithology. The Lithology map is a pictorial representation of the lithology behind casing. It is based on a number of assumptions, density cut-offs, clay cut-offs, Gamma Ray influence (labelled Shale) etc. The map is scaled in volume units from 0 to 100 percent volume. Quad Effective Porosity is presented on the map as QEP curve. The effective porosity is determined by subtracting Shale Porosity from Quad Neutron Total porosity (presented in Gamma Ray Track).

Two other curves on the log worth mentioning is the Bottom Borehole Resistivity Monitor curve (BBRM) and the Normalized Bulk Density Porosity curve (DPORN). The BBRM sensor measures the resistivity of the borehole fluids in the well bore. The resistivity correlates directly with fluid salinity and allows us to confirm the salinity profile in the casing. The DPORN curve is computed by normalizing the Relative Bulk Density porosity curve to the Quad Neutron Total Porosity (QTP) curve. DPORN is presented along with QTP to highlight gas and clay volume changes in the formation.

QUAD NEUTRON TRACE LOG

Roke

Company	ORMAT
Well	Kapoho State 13 (KS-13)
Field	Kilauea East Rift Zone
Country	USA
State	Hawaii

Company ORMAT
Well Kapoho State 13 (KS-13)
Field Kilauea East Rift Zone
Country USA **State** Hawaii

UWI:

Other Services
NONE

Surface Location:

Well License:

Permanent Datum	Ground Level	Elevation	Elevation
Log Measured From 0	ft above P.D.		K.B.
Drilling Measured From Kelly Bushing			G.L.

Date	14-May-16	Correlation Log Name	Casing Tally Sheet
Job Code #	160514-mt1	Correlation Log Date	
AFE #		Cement Top	NOT LOGGED
Depth Driller	4397.0 ft	Type Fluid	Fresh Water / Salty Water
PBTD Logger	4392 ft	Fluid Level	930.0 ft
Btm Log Interval	4388.0 ft	Wellhead Pressure	0 kPa
Top Log Interval	2000.0 ft	Max. Temp.	224 degF
Date / Time RIH	14-May 10:30	Maximum Deviation	0.0 °
Rig Time (hh:mm)	20 hrs	Hoist Unit #	Portable
Recorded By	Mircea Toader	Location	Tiger / Bakersfield
Witnessed By			

Wellbore Information

Type	Size (in)	WT (lb/ft)	From (ft)	To (ft)	Grade
Conductor	30"		0.00	100.00	
Surface	22"		0.00	954.00	
Intermediate	16"		0.00	2076.00	
Production	11 3/4"		0.00	4887.02	

Comments

Correlated to Casing collars

Neutron base pass done with fresh water (FW) in borehole and formation.

Neutron trace pass done with salt water (SW) in borehole and formation.

Non-standard Lithology types presented on log.

No fluid movement detected over logged interval. Suspect fluid moving down.

Fluid movement will be shown as an increase in Short Neutron Gamma (SNG) between Fresh Water (FW) and Salt Water (SW). SNG_SW > SNG_FW
Fluid movement will also be shown as a decrease in Short Neutron Neutron (SNN) between Fresh Water (FW) and Salt Water (SW). SNN_SW < SNN_FW
SNN and SNG Salt water passes normalized to Fresh Water passes at top of logged interval to remove borehole salinity effects.

Roke

Quad Neutron

TOOL DIAGRAM

KS 13

Sensor	Offset (m)
UHT	4.07
UBRM	4.07
GR	3.78
FGR	3.26
CCL	2.41
LNG	
SNG	
SNN	
LNN	
BHT	
BBRM	0.00

Schematic

Description	Len (m)	OD (mm)	Wt (kg)
CableHeadSub QuadV2 to GOI Cable Head Sub	0.24	43.00	1.00
QUADV2_TEL14 Quad V2 Telemetry Combo A	1.97	43.00	20.00
QUADV2_MN15 Quad V2 MN Section	2.13	43.00	20.00
QUADV2_BHT04 Sensors For Processing	0.00	43.00	

Dataset:	Quad
Total Length:	4.34 m
Total Weight:	41.00 kg
O.D.	43.00 mm

Roke

Quad Neutron

MD TRACER LOG

KS 13

Thru Casing

Measured Depth 2000.0 - 4400.0 f

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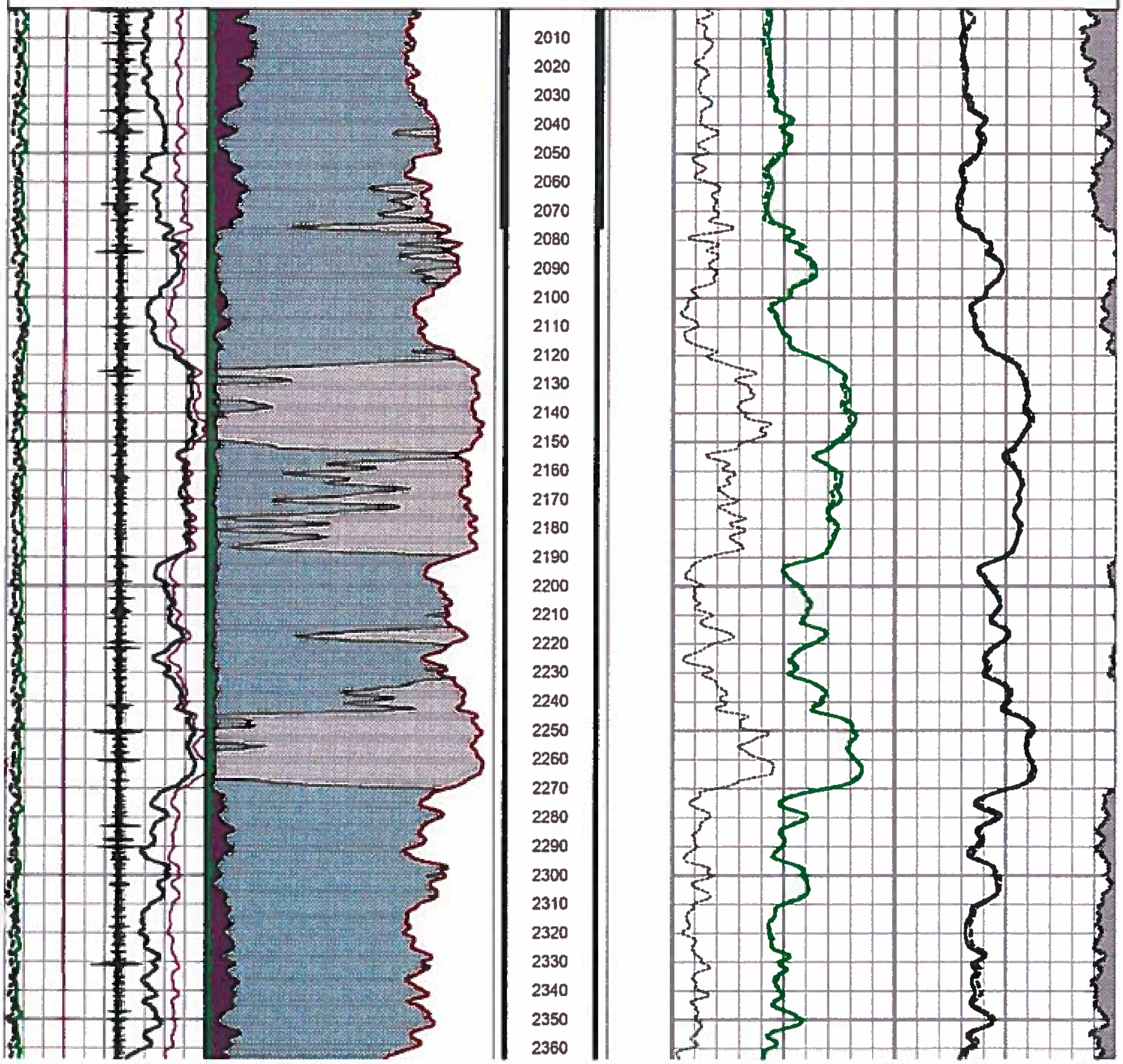
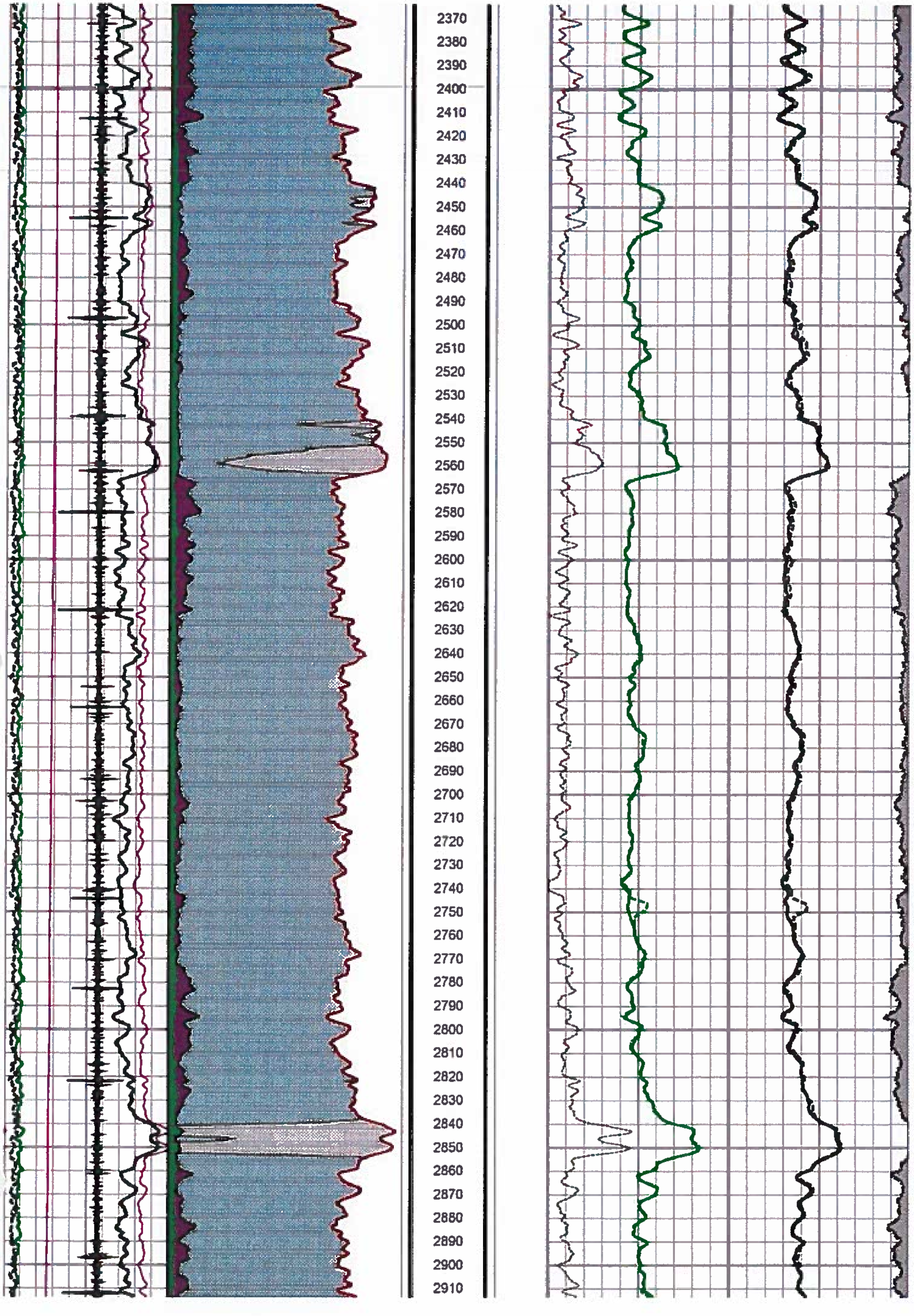
Dataset Printed 2016-05-16 3:34:56 PM
Depth in Feet scaled 1:600

Primary Pass main.las
Processing QN-M
Charted by: akalistratov@roke.ca
v4.16.10

Gamma Ray [GR] 0 (API) 150	QUAD Effective porosity 100 [QEP] (pu) 0	Depth	Relative Bulk Density 3 [CE] (pu) -27	10 Quad Clay [QC] (pu) 0
Filtered GR [FGR] 0 (API) 115	High Bulk Density Material		9000 SNN_FW (cps) 17000	7000 SNG_SW (cps) 13000
Bottom Borehole Resistivity 0 [BBRM] (cps) 40000	Magnesium		9000 SNN_SW (cps) 17000	7000 SNG_FW (cps) 13000
25000 CCL -13000	Basalt			Clay
QUAD Total porosity 100 [QTP] (pu) 0	Shale			
Normalized Bulk Density 100 Porosity [DPORn] 0				

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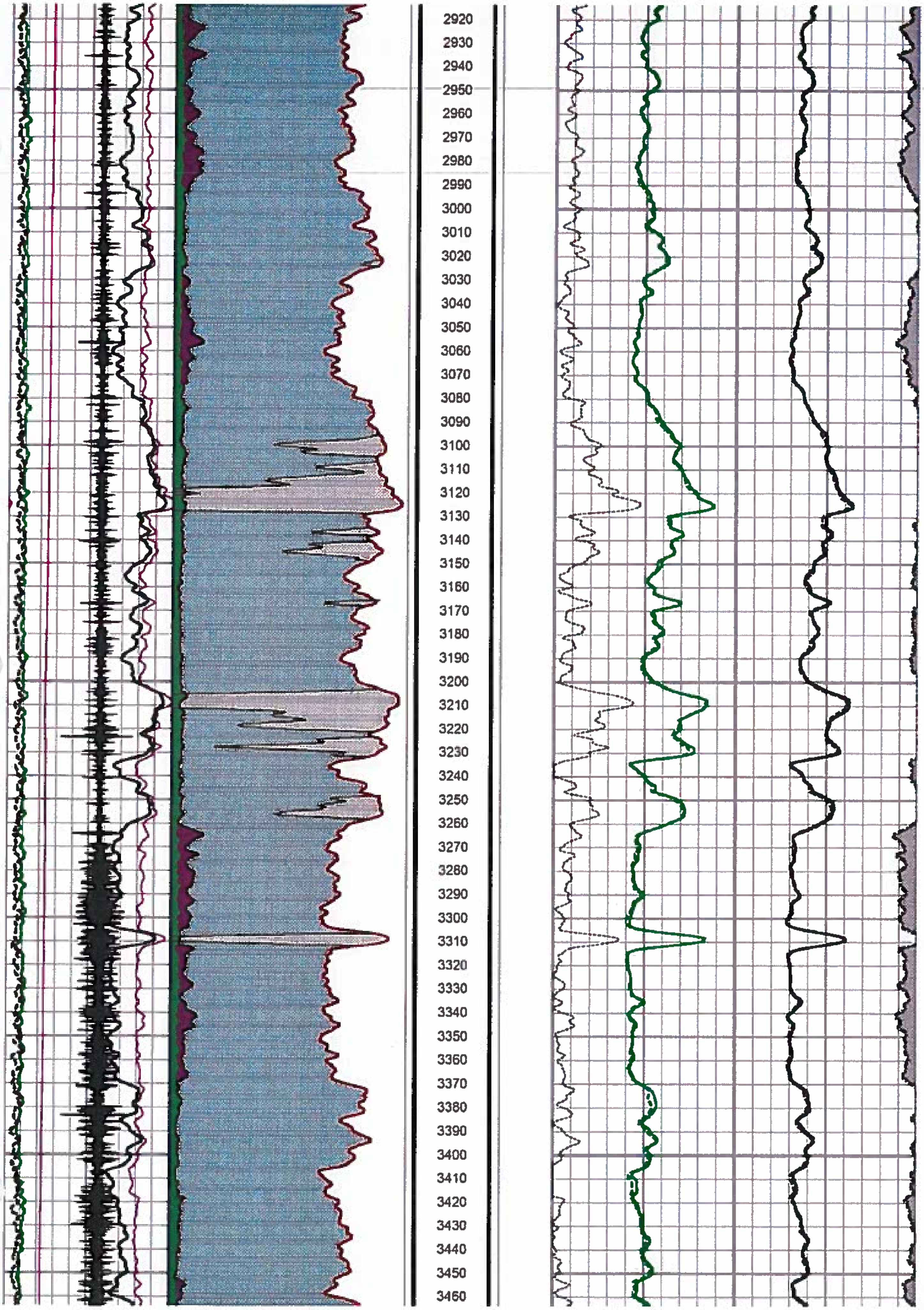
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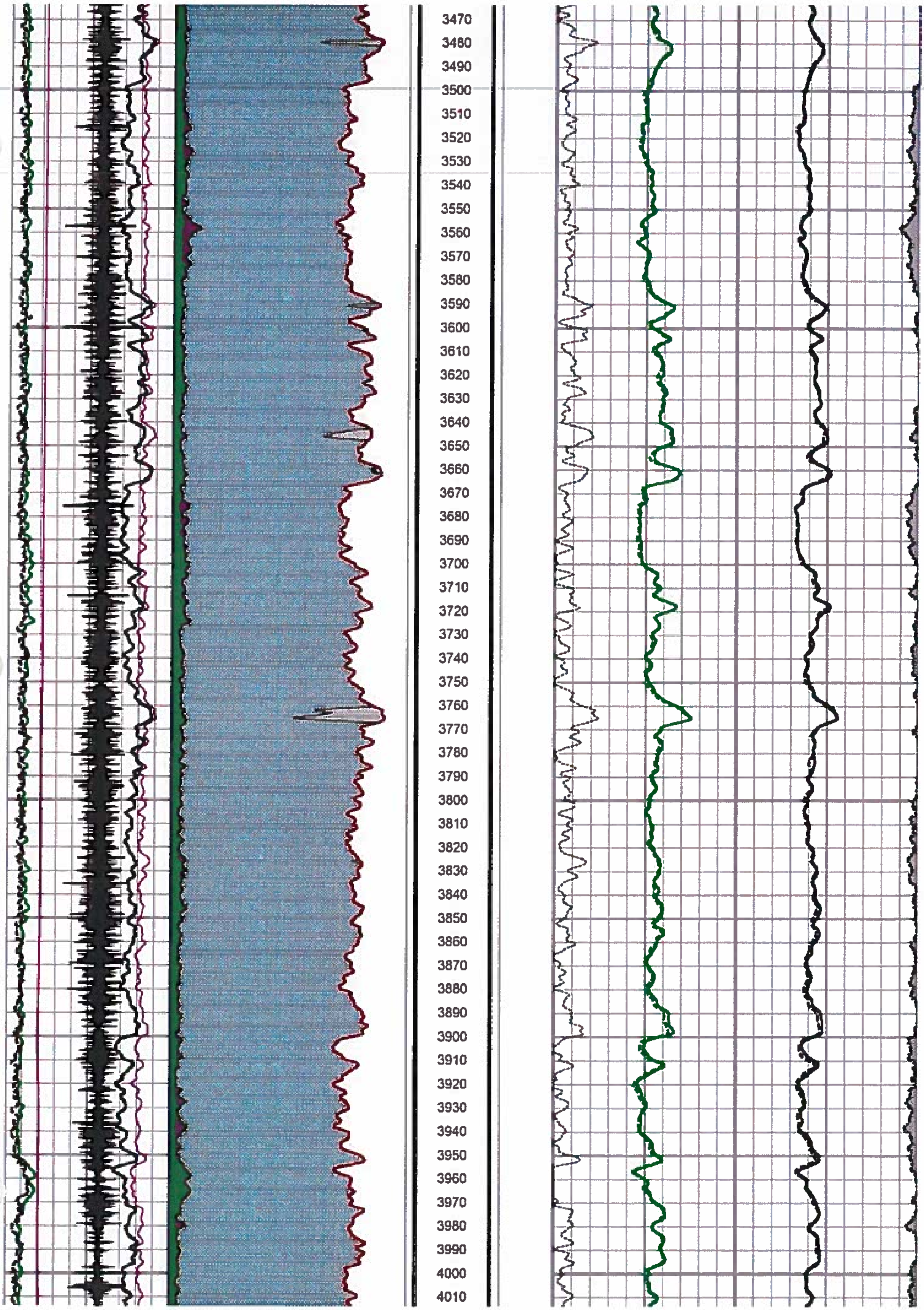
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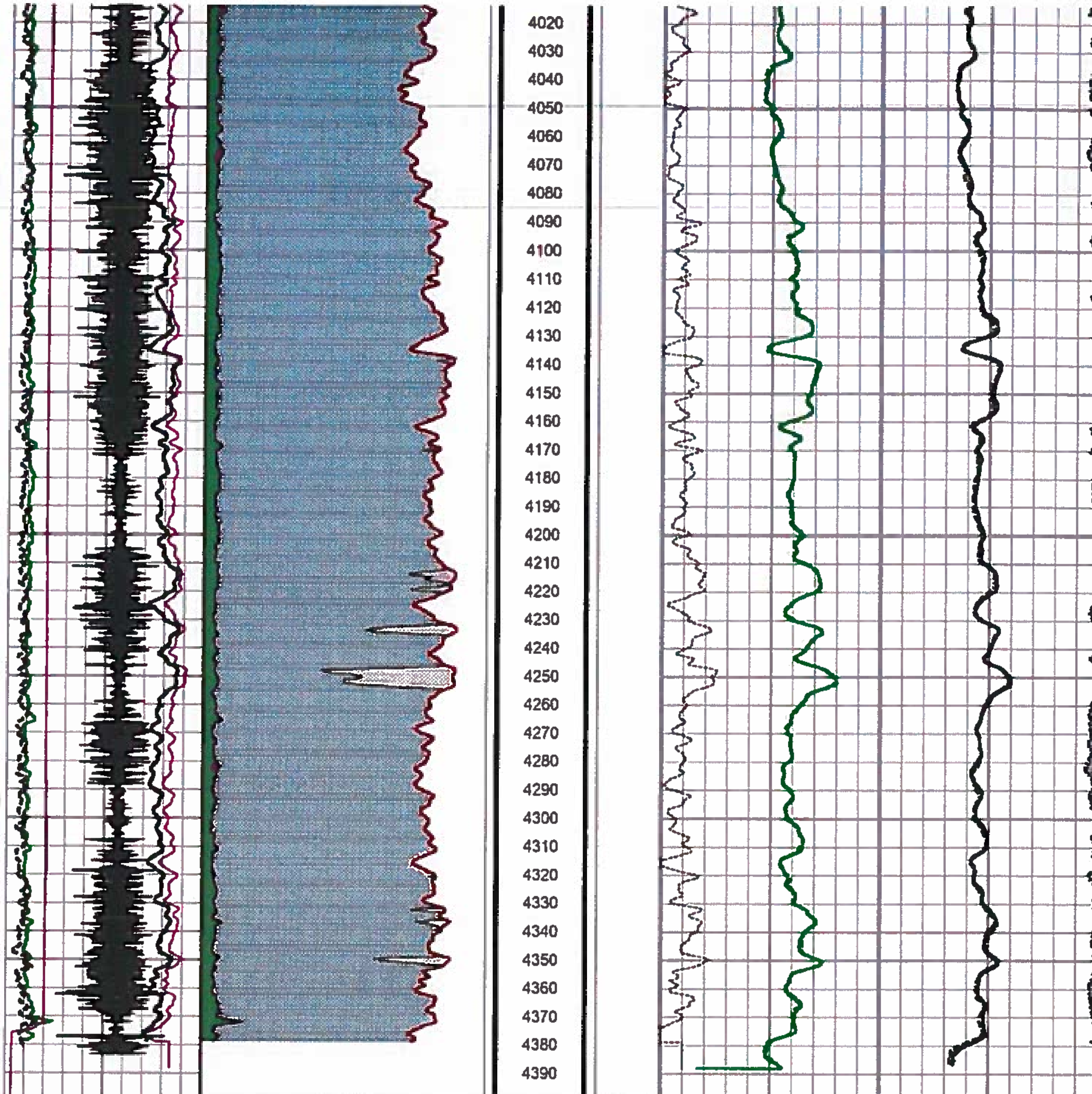

Gamma Ray [GR]
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Filtered GR [FGR]
0 (API) 115

Bottom Borehole Resistivity
0 [BBRM] (cps) 40000

25000 CCL -13000

QUAD Total porosity
100 [QTP] (pu) 0

Normalized Bulk Density
100 Porosity [DPORn] 0

QUAD Effective porosity
100 [QEP] (pu) 0

High Bulk Density Material

Magnesium

Basalt

Shale

Depth

Relative Bulk Density
3 [CE] (pu) -27

9000 SNN_FW (cps) 17000

9000 SNN_SW (cps) 17000

10 Quad Clay [QC] (pu) 0

7000 SNG_SW (cps) 13000

7000 SNG_FW (cps) 13000

Clay

Roke

Quad Neutron

MD TRACER LOG

KS 13

Measured Depth

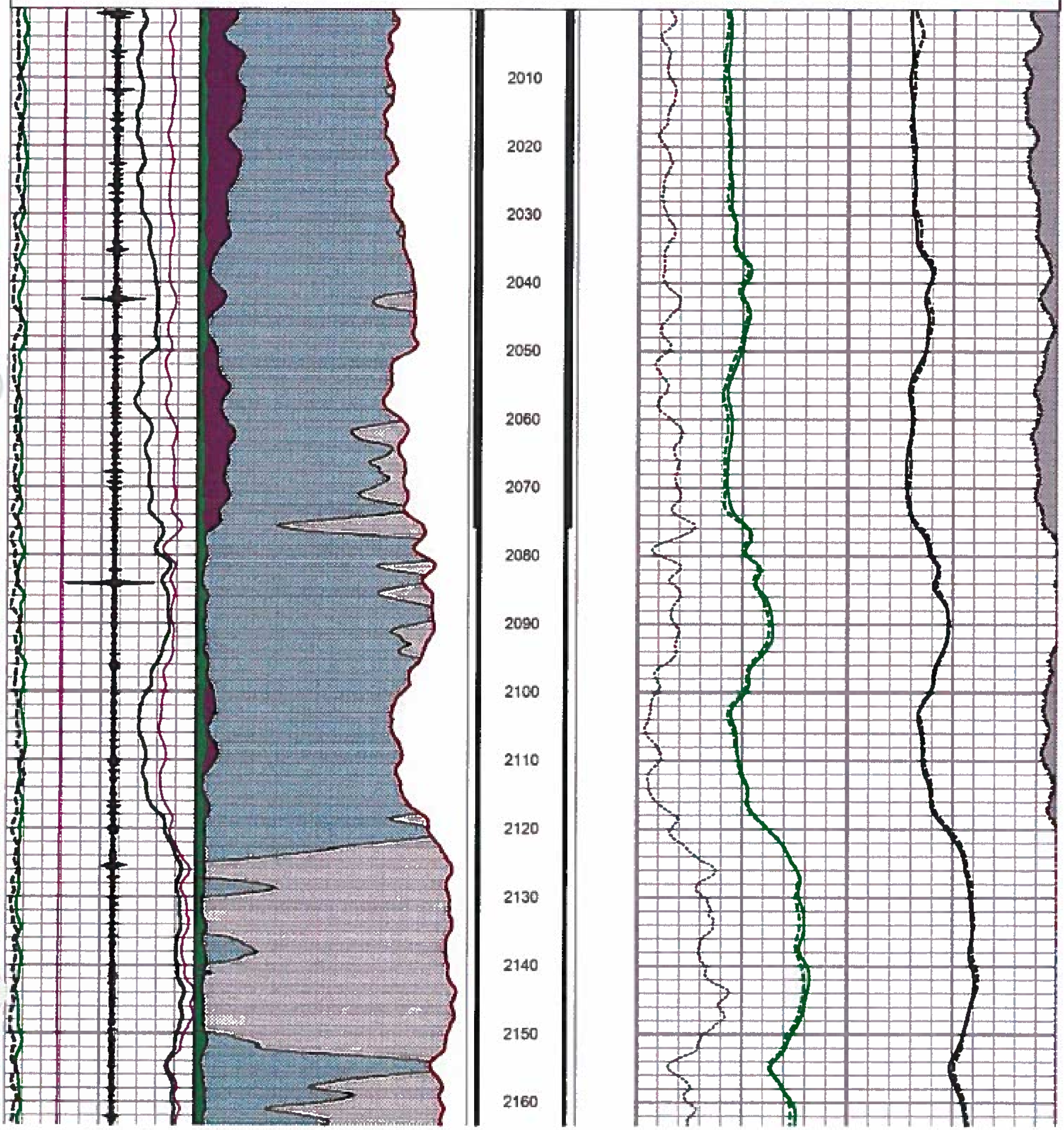
Thru Casing

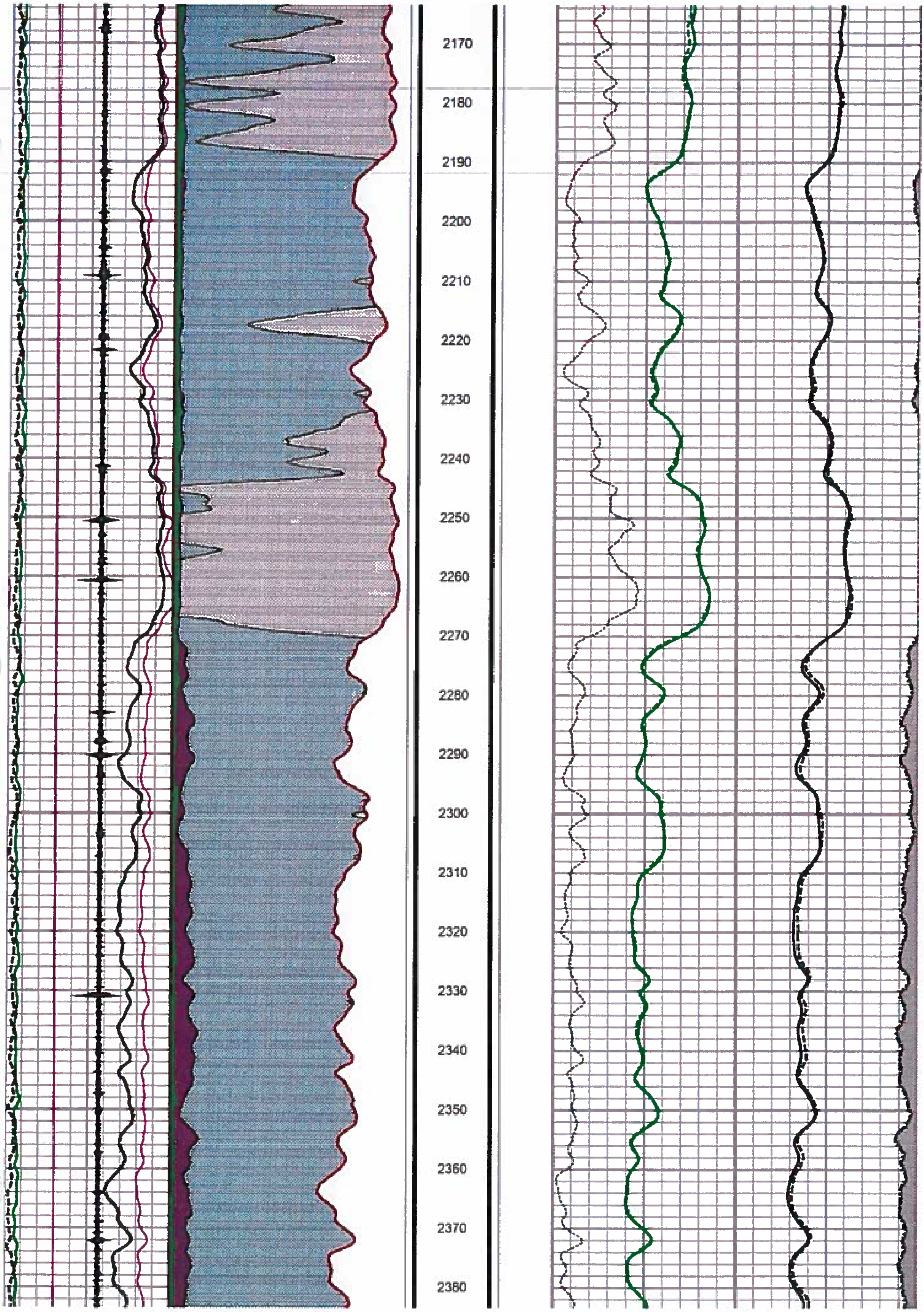
2000.0 - 4400.0 f

Database File: A:\DATA\JOB DATA\2016\05_MAY\160514-MT FORMAT KS13\PROC AK
Presentation Format: TRACER.prs
Dataset Printed: 2016-05-18 3:34:38 PM
Depth in Feet scaled 1:240

Primary Pass.main.las
Processing QN-M
Charted by: akalstratov@roke.ca
v4.16.10

Gamma Ray [GR] 0 (API) 150	QUAD Effective porosity 100 [QEP] (pu) 0	Depth	Relative Bulk Density 3 [CE].(pu) -27	10 Quad Clay [QC] (pu) 0
Filtered GR [FGR] 0 (API) 115	High Bulk Density Material		9000 SNN_FW (cps) 17000	7000 SNG_SW (cps) 13000
Bottom Borehole Resistivity 0 [BBRM] (cps) 40000	Magnesium		9000 SNN_SW (cps) 17000	7000 SNG_FW (cps) 13000
25000 CCL -13000	Basalt			Clay
QUAD Total porosity 100 [QTP] (pu) 0	Shale			
Normalized Bulk Density 100 Porosity [DPORn] 0				

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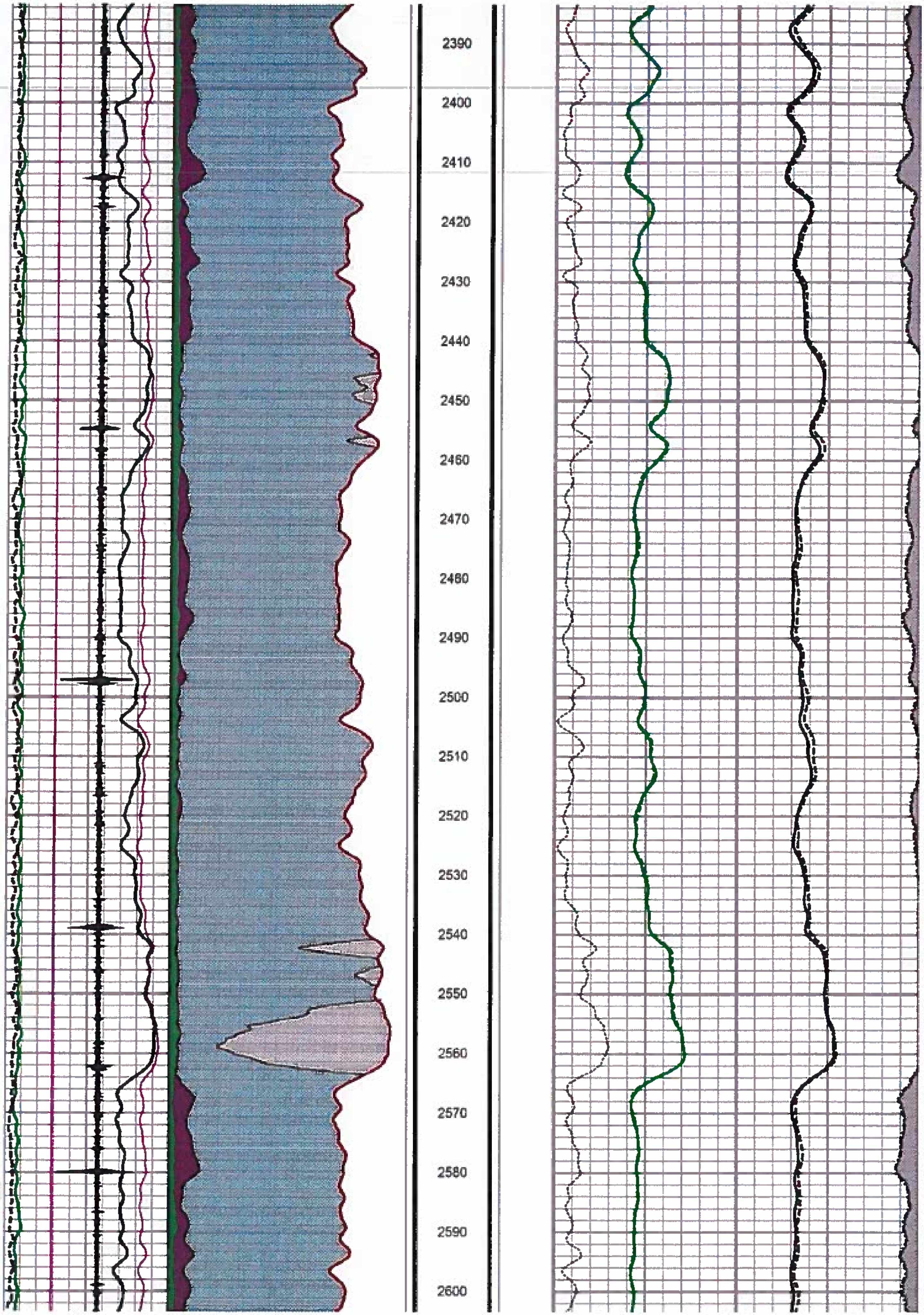
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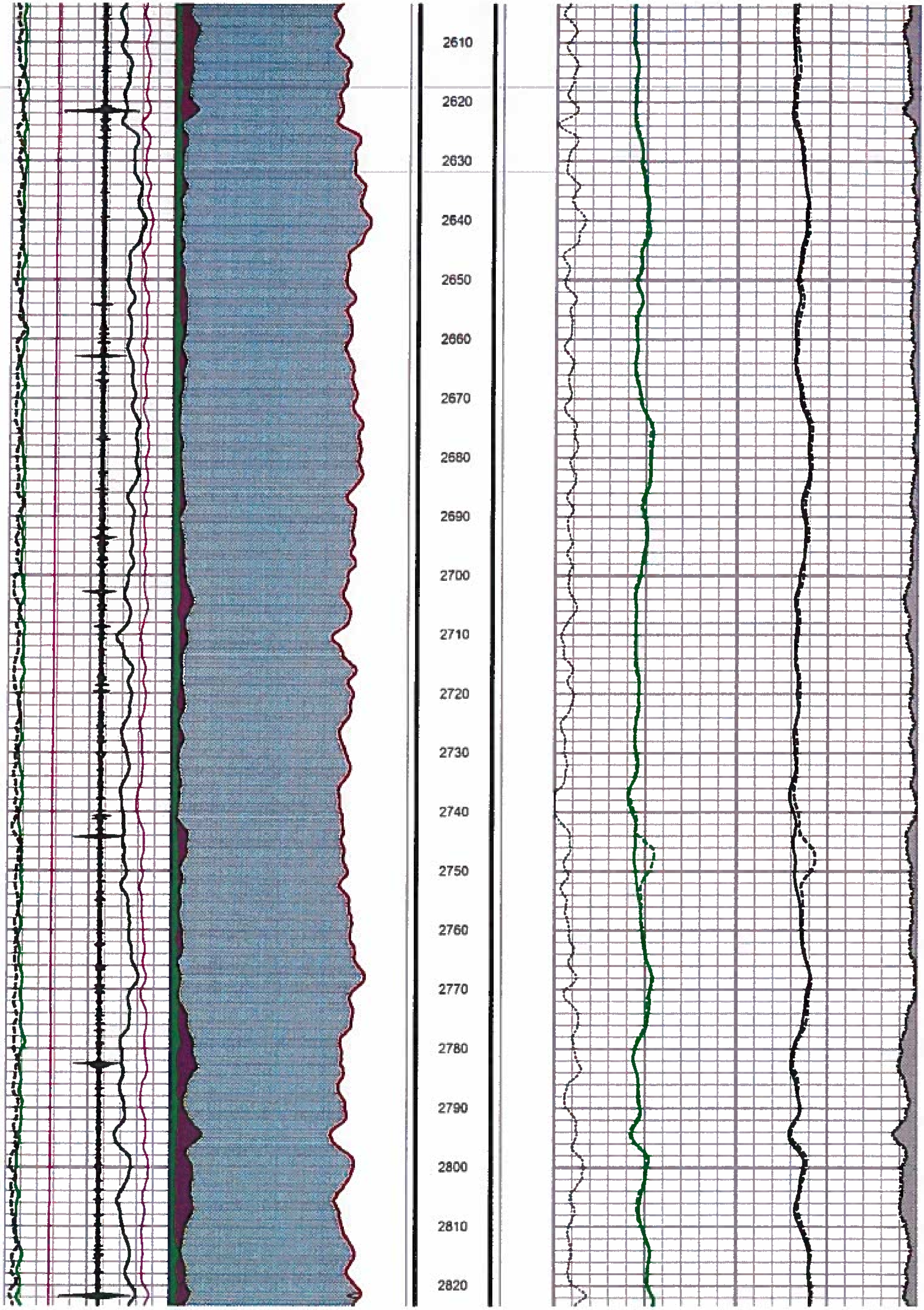
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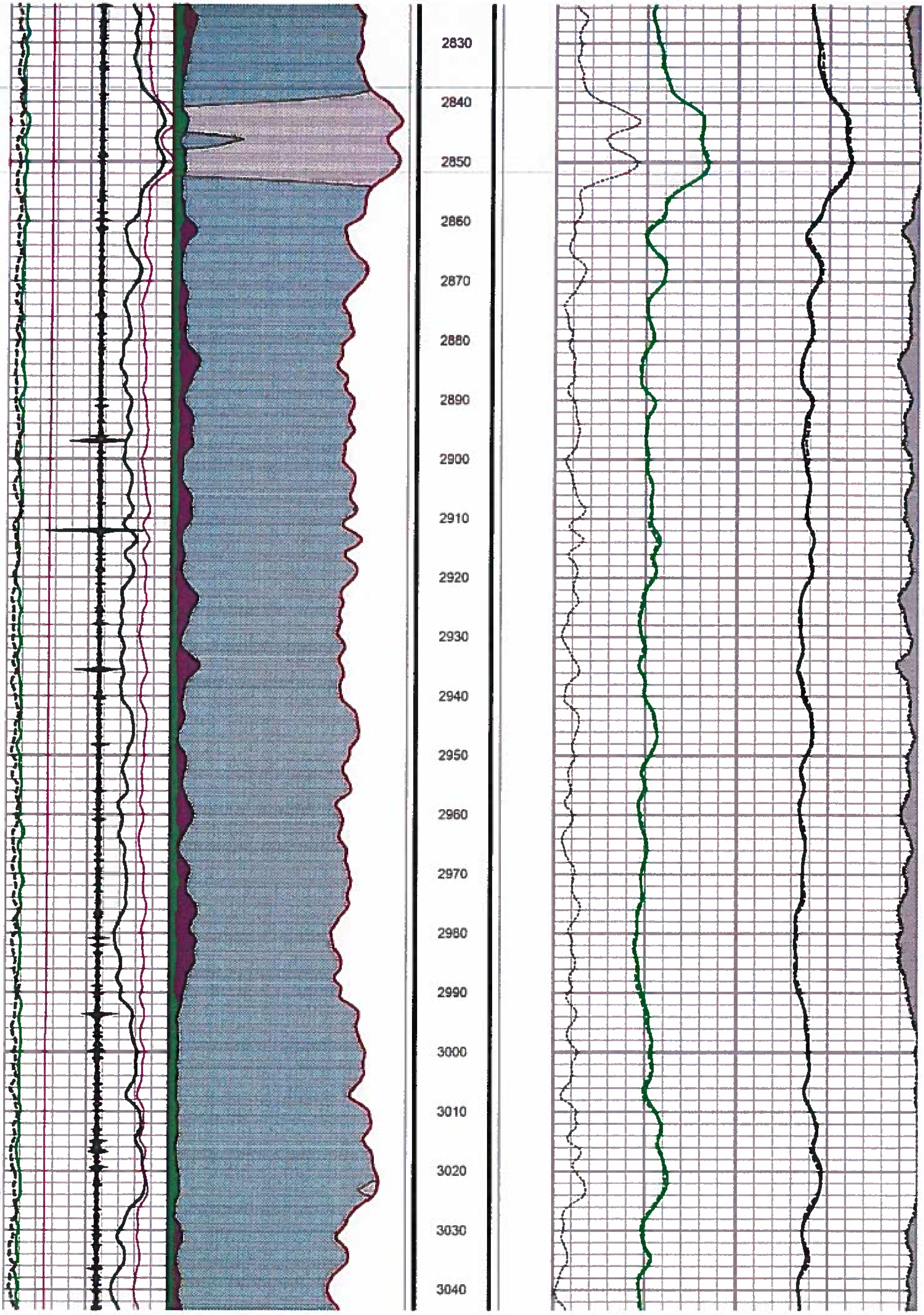
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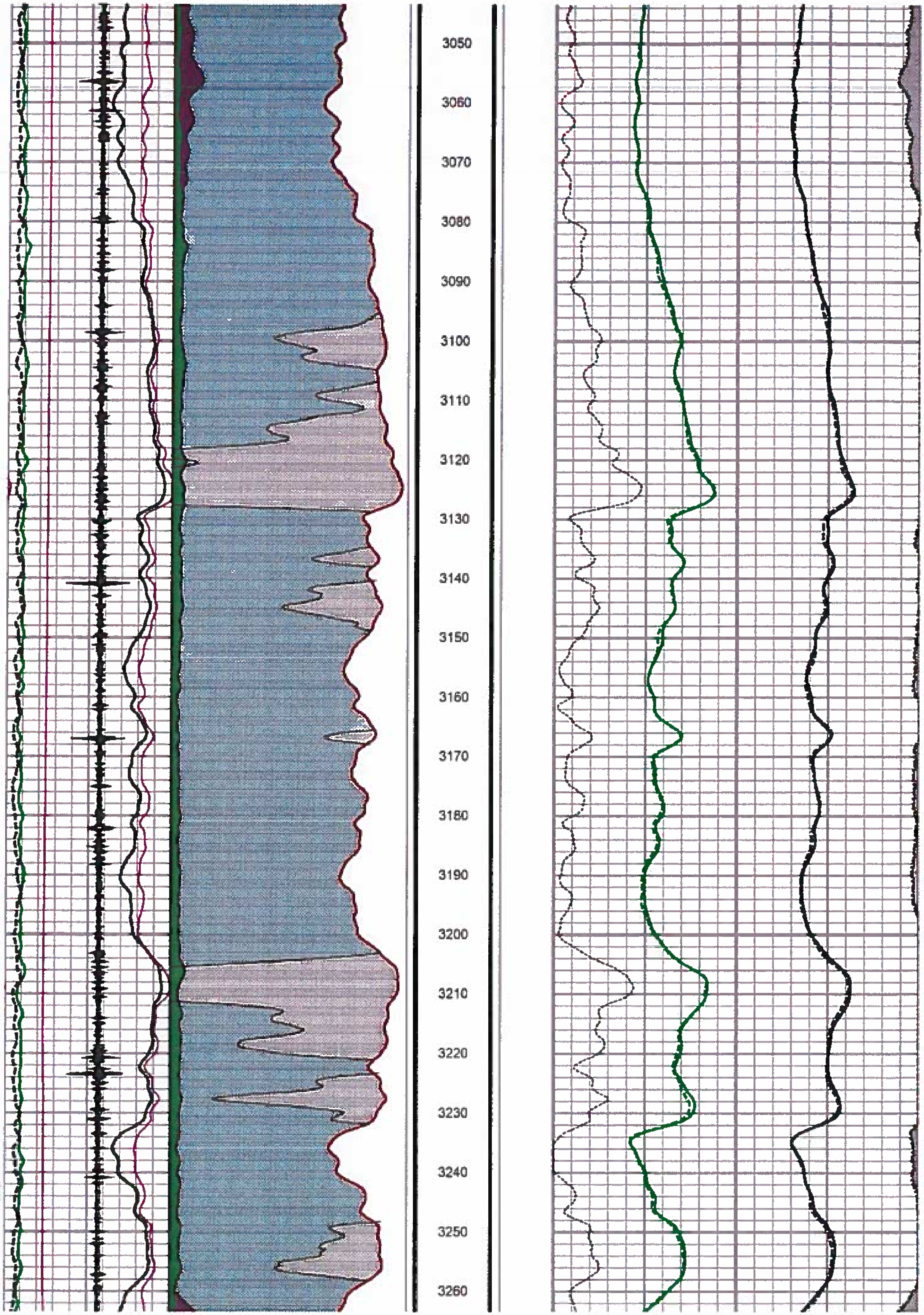
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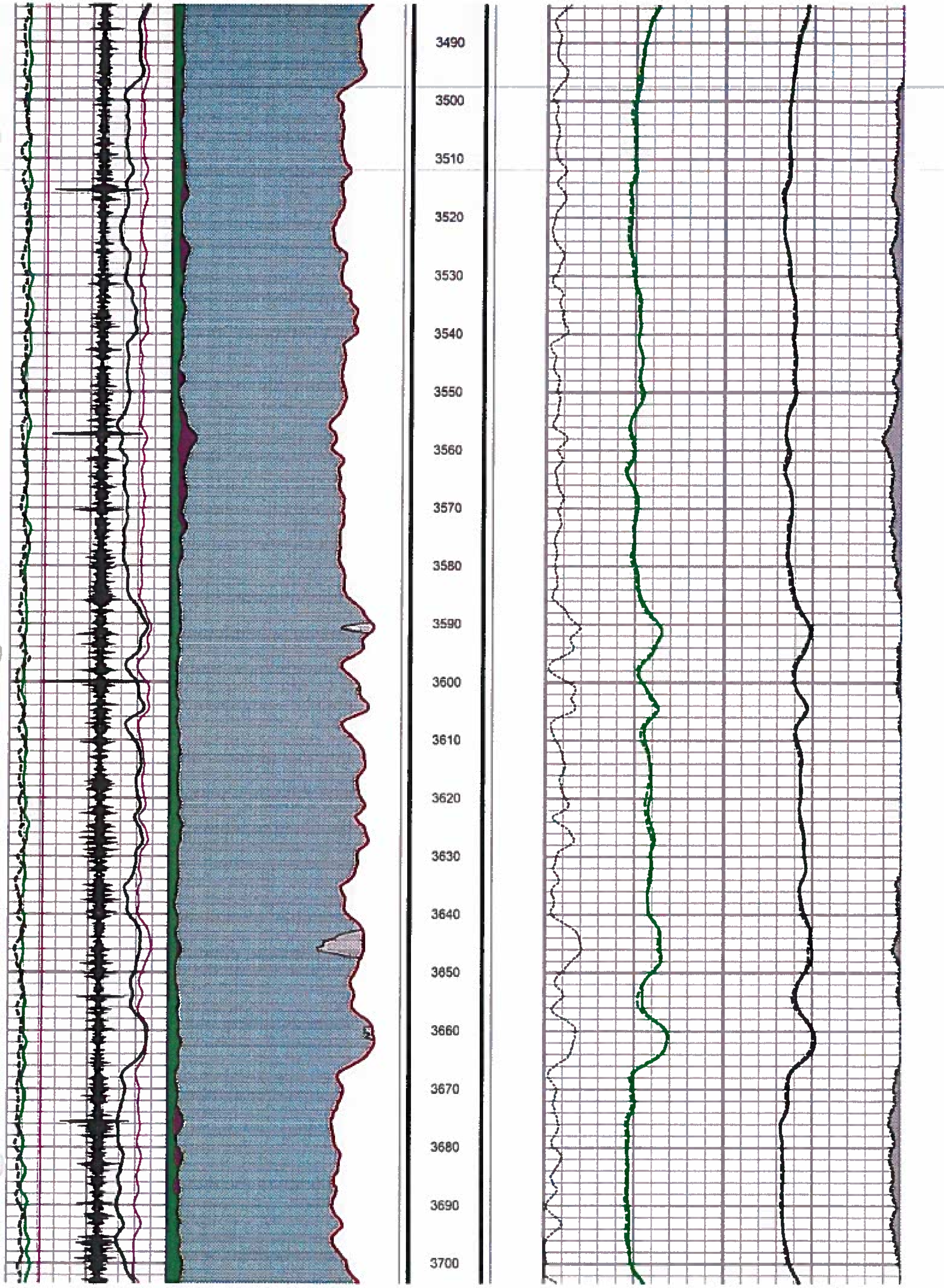
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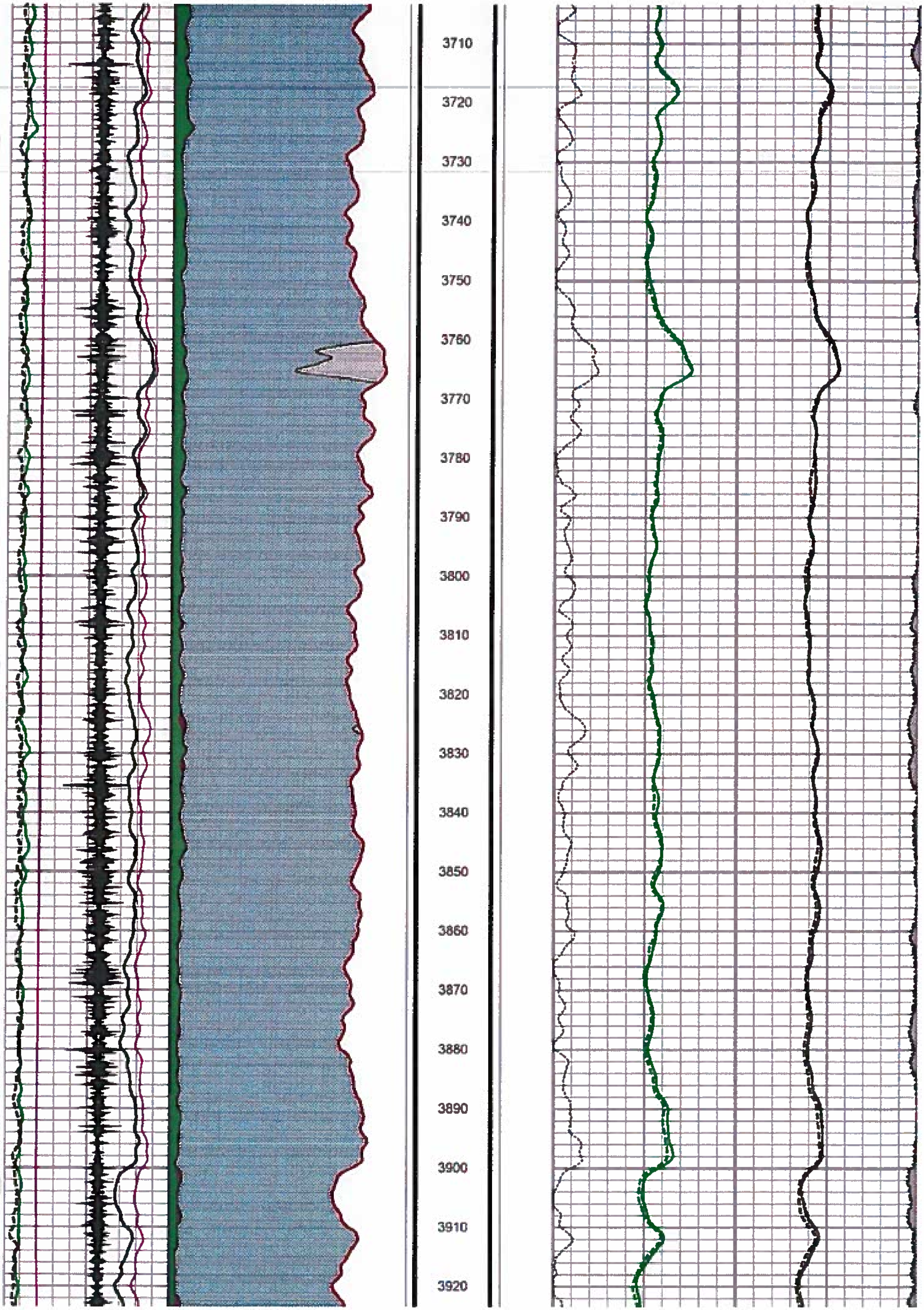
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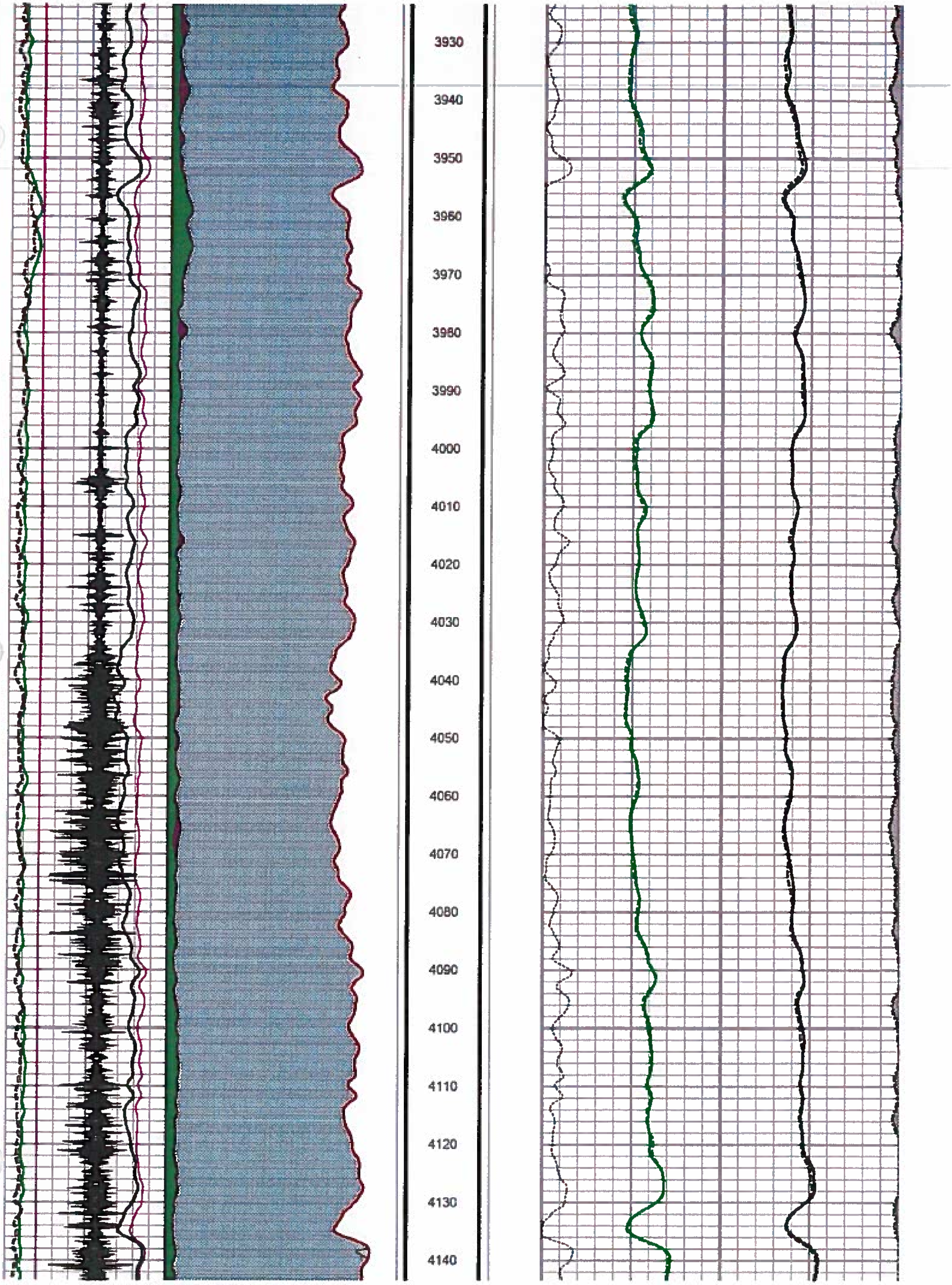
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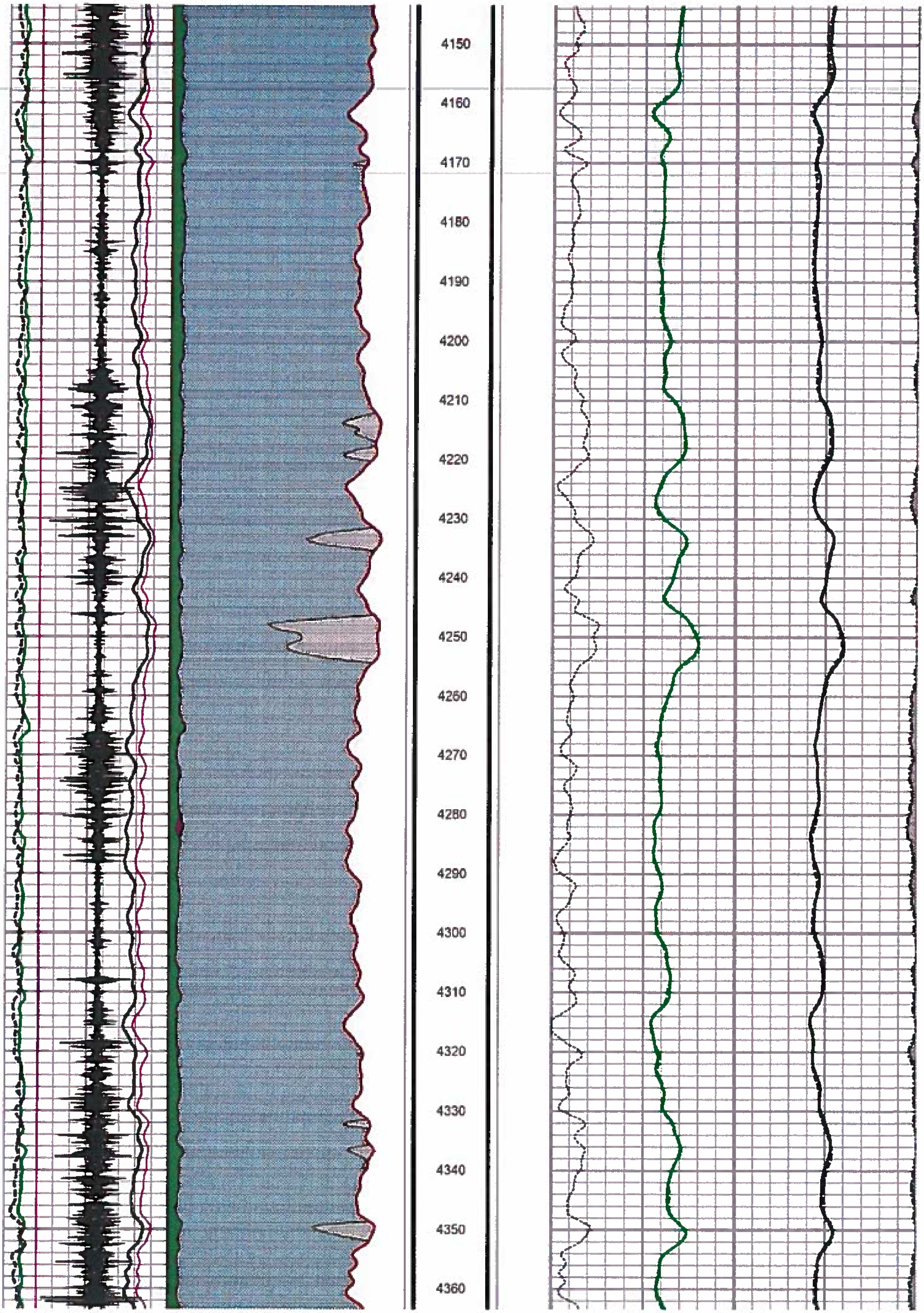
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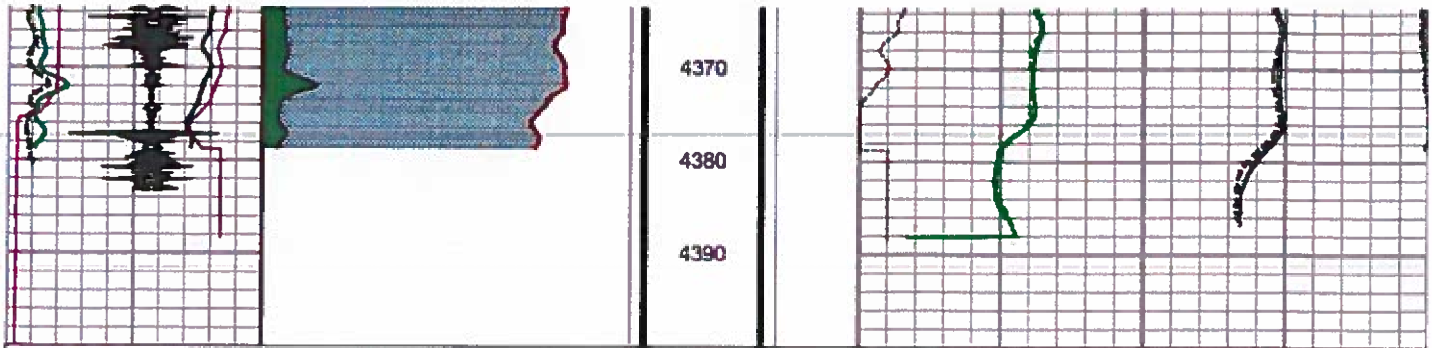


Gamma Ray [GR]	QUAD Effective porosity	Depth	Relative Bulk Density	Quad Clay [QC] (pu)
0 (API) 150	100 [QEP] (pu) 0		3 [CE].(pu) -27	10 Quad Clay [QC] (pu) 0
Filtered GR [FGR] 0 (API) 115	High Bulk Density Material		9000 SNN_FW (cps) 17000	7000 SNG_SW (cps) 13000
Bottom Borehole Resistivity 0 [BBRM] (cps) 40000	Magnesium		9000 SNN_SW (cps) 17000	7000 SNG_FW (cps) 13000
25000 CCL -13000	Basalt			Clay
QUAD Total porosity 100 [QTP] (pu) 0	Shale			
Normalized Bulk Density 100 Porosity [DPORn] 0				

TRoke

Quad Neutron

Thru Casing

MD TRACER LOG

KS 13

Measured Depth

2000.0 - 4400.0 f

Calibrations

Curve	Gain	Shift	Filter	Offset
CCL	1	0	0	2 42
FGR	1 63	0	1	3 28
BHT	0 002421	-83 6	1	0
GR	0.82	0	1	4 26
UHT	0 004261	-156 93	1	4 23

Curve	Gain	Shift	Filter	Offset
LNN	1.25	0	1 2	1 33
BBRM	1 005542	0	0	0.13
SNG	1 015	0	1 8	1.76
SNN	1.28	0	1.5	1 44

Curve	Gain	Min	Max	Filter	Offset
LNG	1.12	1 035	1.115	1 5	1 43

Zone 1

Top: 2000.00 f	Bottom: 4400 00 f	low compaction		nuclear caliper gain 1	water:14 kppm	oil 15 API	f-factor 20	ce gain 0	clay tie 4190
Curve	A	B	Gain	Shift	Curve	WT	Cutoff	Min	Max
QTP	52	-16.8	0 8	-12	DGR	0	10	0	65
QL	24 475	-22 25	0 89	0	GR	0	20	0	60
DDN	2 16	-19.9	0 9	-1	DDN	25	4	0	60
QC	0 004	-1	1	-1	QC	0	2	0	100
SNNp	-134	76	-134	76	PROP	0	0	0	60
LNNp	-13	56.4267	-13	56 4267	CE	0	3	0	60
SNGp	-89	141 3389	-89	141 3389	COAL	1	42	0	60
LNGp	-18	92.7338	-18	92 7338	calcite	1	15	0	60
FGR	1	0	1	0	CEp	75	4	0	100
CEp	1	0	1 6	16					
SNNpost	1	0	1	0					
SNGpost	1	0	1	0					
CNL	1	0	1	3					
IntCounts	1	0	1	0					
Saturation	QLce	ddn 0 5	clay 20	boundwater 0	waterfreeoil 0 65	boundoil 0 2	filter 1	swak False	
	coll maxclay False	coll swqcfp True	use snnp-lnnp False	snnp-lnnp 0	swoilcor 120827-HK				
Lithology	shale:7	silt (bliquid):15	sand:0	collector:7	calcite min:-2	calcite max:-7	coal porosity 60	hcoal 65	
	use qc	lgrshale 80	lgrsand 0	lgrcollcut 1	carbonate:True	dolasmud False	minclayfe:20	qtpqlfe 20	
	fe100 20	nofe 20							

unexpected formation pressures, the lessee shall submit a revised casing program to the District Supervisor for approval. The District Supervisor may permit a lessee to drill a well without setting conductor casing provided the information from approved logging and mud-monitoring programs for wells previously drilled in the immediate vacinity combined with other available geologic data are sufficient to demonstrate the absence of shallow hydrocarbons or hazards.

(2) *Conductor casing cementing requirements.* Conductor casing shall be cemented with a quantity of cement that fills the calculated annular space back to the mud line except as applicable to the bottom of an excavation (glory hole) or to the surface of an artificial island. Cement fill in annular spaces shall be verified by the observation of cement returns. In the event that observation of cement returns is not feasible, additional quantities of cement shall be used to assure fill to the mud line.

(3) *Surface casing cementing requirements.* (i) Surface casing shall be cemented with a quantity of cement that fills the calculated annular space to at least 200 feet inside the conductor casing. When geologic conditions such as near-surface fractures and faulting exist, surface casing shall be cemented with a quantity of cement that fills the calculated annular space to the mud line, or as approved or prescribed by the District Supervisor.

(ii) For floating drilling operations, a lesser volume of cement may be used to prevent sealing the annular space between the conductor casing and surface casing if the District Supervisor determines that the uncemented space is necessary to provide protection from burst and collapse pressures which may be applied inadvertently to the annulus between casings during blowout preventer (BOP) testing operations. Any annular space open to the drilled hole shall be sealed in accordance with the requirements for abandonment in subpart G, Abandonment of Wells, of this part.

(d) *Intermediate casing requirements.* (1) Intermediate casing string(s) shall be set for protection when geologic characteristics or wellbore conditions, as anticipated or as encountered, so indicate.

(2) Quantities of cement that cover and isolate all hydrocarbon-bearing zones in the well and isolate abnormal pressure intervals from normal pressure intervals shall be used. This requirement for isolation may be satisfied by squeeze cementing prior to completion, suspension of operations, or abandonment, whichever occurs first. Sufficient cement shall be used to provide annular fill-up to a minimum of 500 feet above the zones to be isolated or 500 feet above the casing shoe in wells where zonal coverage is not required.

(3) If a liner is to be used as an intermediate string below a surface casing string, it shall be lapped a minimum of 100 feet into the previous casing string and cemented as required for intermediate casing. When a liner is to be used as production casing below a surface casing string, it shall be extended to the surface and cemented to avoid surface casing being used as production casing.

(e) *Production casing requirements.* (1) Production casing shall be cemented to cover or isolate all zones above the shoe which contain hydrocarbons; but in any case, a volume sufficient to fill the annular space at least 500 feet above the uppermost hydrocarbon-bearing zone shall be used.

(2) When a liner is to be used as production casing below intermediate casing, it shall be lapped a minimum of 100 feet into the previous casing string and cemented as required for the production casing.

§ 250.55 Pressure testing of casing.

(a) Prior to drilling the plug after cementing and in the cases of plugs in production casing strings and liners not planned to be subsequently drilled out, all casings, except the drive or structural casing, shall be pressure tested to 70 percent of the minimum internal-yield pressure of the casing or as otherwise approved or required by the District Supervisor. If the pressure declines more than 10 percent in 30 minutes or if there is another indication of a leak, the casing shall be recemented, repaired, or an additional casing string run and the casing pressure tested again. Additional remedial actions shall be taken until a satisfactory pressure test is obtained. The results of all casing pressure tests shall be recorded in the driller's report.

(b) Each production liner lap shall be tested to a minimum of 500 psi above formation fracture pressure at the shoe of the casing into which the liner is lapped, or as otherwise approved or required by the District Supervisor. The drilling liner-lap test pressure shall be equal to or exceed the pressure that will be encountered at the liner lap when conducting the planned pressure-integrity test below the liner shoe. The test results shall be recorded on the driller's report. If the test indicates an improper seal, remedial action shall be taken which provides a proper seal as demonstrated by a satisfactory pressure test.

(c) In the event of prolonged drill-pipe rotation within a casing string run to the surface or extended operations such as milling, fishing, jarring, washing over, and other operations which could damage the casing, the casing shall be pressure tested or evaluated by a logging technique such as a caliper log every 30 days. The evaluation results shall be submitted to the District Supervisor with a determination of effects of operations on the integrity of the casing for continued service during drilling operations and over the producing life of the well. If the integrity of the casing in the well has deteriorated to an unsafe level, remedial operations shall be conducted or additional casing set in accordance with a plan approved by the District Supervisor prior to continuing drilling operations.

(d) After cementing any string of casing other than the structural casing string, drilling shall not be resumed until there has been a time lapse of 8 hours under pressure for the conductor casing string and 12 hours under pressure for all other casing strings. Cement is considered under pressure if one or more float valves are shown to be holding the cement in place or when other means of holding pressure are used.

§250.56 Blowout preventer systems and system components.

(a) *General.* The BOP systems and system components shall be designed, installed, used, maintained, and tested to assure well control.

(b) *BOP stacks.* The BOP stacks shall consist of an annular preventer and the number of ram-type preventers as specified under paragraphs (e)(1), (f), and (g) of this section. The pipe rams shall be of a proper size(s) to fit the drill pipe in use.

(c) *Working pressure.* The working-pressure rating of any BOP component shall exceed the anticipated surface pressure to which it may be subjected. The District Supervisor may approve a lower working pressure rating for the annular preventer if the lessee demonstrates that the anticipated or actual well conditions will not place demands above its rated working pressure. (Refer to related requirements in §250.64(f)(3)(ii) of this part.)

(d) *BOP equipment.* All BOP systems shall be equipped and provided with the following:

(1) An accumulator system which shall provide sufficient capacity to supply 1.5 times the volume of fluid necessary to close and hold closed all BOP equipment units with a minimum pressure of 200 psi above the precharge pressure without assistance from a charging system. No later than December 1, 1988, accumulator regulators supplied by rig air and without a secondary source of pneumatic supply, shall be equipped with manual overrides or alternately, other devices provided to ensure capability of hydraulic operations if rig air is lost.

(2) A backup to the primary accumulator-charging system which shall be automatic, supplied by a power source independent from the power source to the primary accumulator-charging system, and possess sufficient capability to close all BOP components and hold them closed.

(3) At least one operable remote BOP control station in addition to the one on the drilling floor. This control station shall be in a readily accessible location away from the drilling floor.

(4) A drilling spool with side outlets if side outlets are not provided in the

TITLE: Mechanical Integrity Testing

Revision #: 0
Date of Current Rev:
By: GD
Last Rev: 10/14/10

Procedure Mechanical Integrity Testing

Possible means of proving mechanical integrity of a geothermal well:

1. Make a sinker bar run using a sinker bar with a larger o.d. than p/t tools.
   a. Run In Hole (RIH) to ~ 3000' to insure that well bore is open.
   b. RIH @ a slow rate ~ 60'/min. to minimize the chance of getting hung up.

2. Perform pressure temperature (p/t) survey to desired depth ~3000'.
   a. This will determine static fluid level in the well bore.
   b. This will also identify bottom hole temperatures and pressures.
   c. A second static survey will verify if abnormal conditions exist, such as fluid communication outside the casing or unusual thermal recovery after injection is stopped.

3. Perform Nitrogen (N2) pressure test on well bore casing.
   a. Calculate pressure needed to depress fluid to 3000'.
   b. Use pressure gauge and chart recorder to monitor pressure losses.
   c. Pressurize well bore with N2 in 500 psi increments. Hold each 30 min.
   d. When calculated pressure is achieved hold for at least 5hrs.
   e. Check all surface equipment for leaks during this evolution.

1A. Schedule for running MIT's
   a. Start in hole with enough time to make stops prior to well shut-in
   b. Wait on bottom 90 minutes after shut-in, POH running 1st static log
   c. Run 2nd log 12 hours after shut-in

Note: If the above tests pass satisfactorily it may be considered by some to have acceptable integrity. If not additional testing could possibly be as follows but not limited to.

4. RIH with a gauge ring and allow ~ 1" clearance to Inner Diameter (ID) of casing.

5. RIH with a multi finger caliper to desired depth and log ID of casing while Pulling Out Of Hole (POOH).

6. Run a Bond Log to ensure the cement on the back side of the casing has good integrity. Note: Bottom hole temperatures must be within the ratings of tools.

7. Additional logging may be performed to obtain further information if so desired.

Note: For all logging evolutions refer to the P.G.V. procedure for "Logging Wells"

INJECTION TEST PLAN FOR PGV WELL KS-13 FORK

Paul Spielman
February 26, 2016

The KS-13 fork will be injection tested after the liner is run and the hole is surged but before the whipstock is retrieved to estimate injectivity increase.

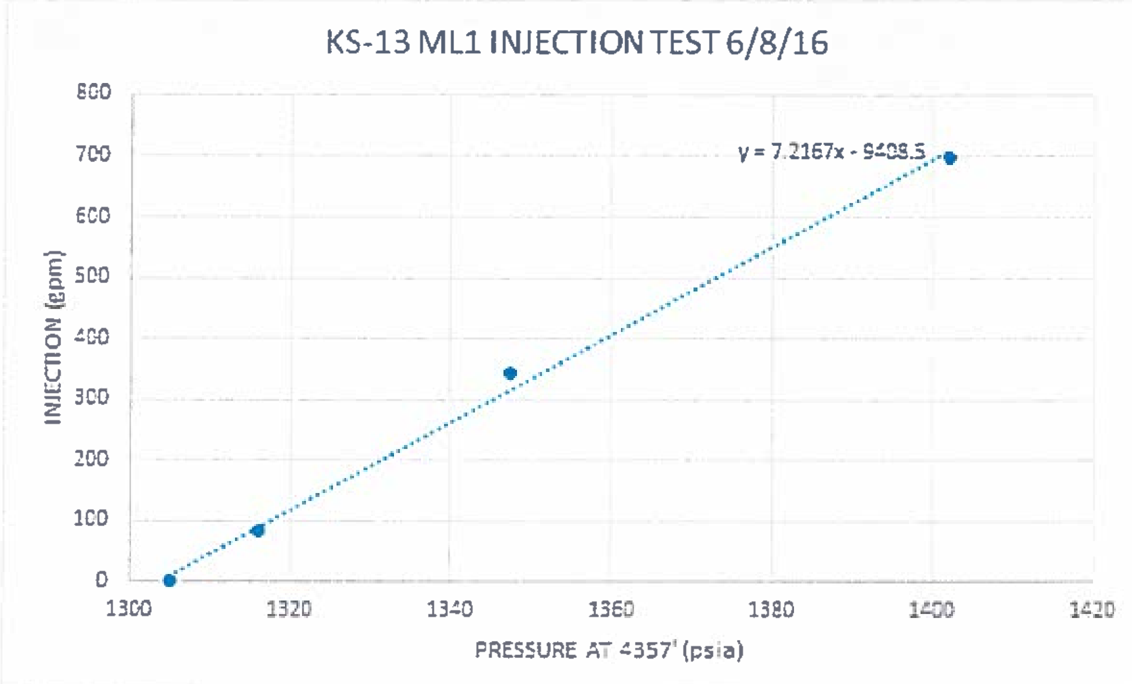
KS-13 COMPLETION
KB: 26 ft
11-3/4" 65# T95 Casing to 4866 ft
Window cut in 11-3/4 at approximately 4400 ft
10-1/2" hole to approximately 7300 ft with 8-5/8" 44# GT80 perforated liner

INJECTIVITY TEST

1. Pump fresh water at 1/3 maximum pump rate while setting up.
2. Run open ended drillpipe to 20 feet below top of the 8-5/8" liner and set in pipe rams.
3. Rig up slick line unit on drillpipe (make sure ahead of time there is a valve and adapter for the lubricator).
4. Run sinker bar to maximum reachable depth. Continue pumping at 1/3 max pump rate.
5. Run high temperature Kuster PT tool to 10 feet above sinker bar set down depth.
6. Pull up to middle of lost circulation zones.
7. Wait for 30 minutes.
8. Increase pump rate to 2/3 maximum pump rate and pump for 1 hour.
9. Increase pump rate to maximum pump rate and pump for 1 hour.
10. Stop pumping and wait for 1 hour.
11. Run PT tool in to 10 feet above sinker bar set down depth.
12. Pull PT tool out of hole at 100 ft/min but slow down below the drillpipe and wellhead.
13. Download data and send it to Paul Spielman at pspielman@ormat.com and Elton Colbert at ecolbert@ormat.com .

Note: Very important to keep constant pumping rates during the entire test.

Another injection test was performed today on KS-13 with both legs open. With 83 gpm of injection, the PT tool was parked at 4357 feet. After a half hour, injection was increased to 342 gpm for an hour and then 680 gpm for an hour and then shut in.



The measured injectivity is 7.2 gpm/psi. The calculated injection capacities are:

WHP psig	KS-13 + ML1 kph
200	1565
250	1697
300	1827
350	1954
400	2079
450	2201

The 1827 kph at 300 psi should be enough to shut in KS-15 and increase plant output to 36 MW. Long term injection capacity will be evaluated after KS-13+ML1 is back on line with hot brine and KS-15 is shut in.

KS-13 prior to drilling was 2.3 gpm/psi and the last test on ML1 measured 5.7 gpm/psi which adds up to 8.0 gpm/psi, 0.8 gpm less than the current measurement. Circulation was lost as soon as the window was cut so cuttings from ML1 might have gone into the original hole (through the annulus or through fractures in the formation) and covered the deepest injection zones. But 0.8 gpm/psi is within the error range of multiple injectivity measurements.

KS-13 FORMATION PRESSURE TEST

$P_{T\text{-}WH}$ = 1450 psig	Pressure at Wellhead
ρ_{mud} = 8.75 ppg	Mud Weight per gallon
MD_{KB} = 4986 feet	Measured Depth
TVD_{KB} = 4969 feet	True Vertical Depth
KB = 26 feet	Kelly Bushing
.052	Conversion PPG to PSI
.8	Safety Factor, 80%

$$P_{T\text{-}shoe} = P_{T\text{-}WH} + 0.052\ \rho_{mud}\ TVD_{KB} = 1450 + (0.052 \times 8.75 \times 4969) = 3711 \text{ psig}$$

Test Pressure Gradient = 3711/4969 = 0.747 psi/ft

$$P_{I\text{-}WH} = P_{T\text{-}shoe} - (80^{\circ}\text{F Pres. Gradient})\ TVD_{GL} = 3711 - 0.434\ (4969 - 26) = 1566 \text{ psig}$$

$$P_{Max\text{-}WH} = 0.8\ P_{I\text{-}WH} = 0.8 \times 1566 = 1252 \text{ psig}$$

Gradient at Max Safe WHP = (1252 + 0.434 (4969 – 26))/ 4969 = 0.684 psi/ft sparks, or other hot materials could fall for potential fire and explosion hazards. After it has been determined that it is safe to proceed with the welding and burning operation, the designated person-in-charge shall issue a written authorization for the work.

(2) During these welding or burning operations, one or more persons shall be designated as a fire watch. The person(s) assigned as a fire watch shall have no other duties while actual welding or burning operations are in progress. If the operation is to be in an area which is not equipped with a gas detector, the fire watch shall also maintain a continuous surveillance with a portable gas detector during the welding and burning operation. The fire watch shall remain on duty for a period of 30 minutes after welding or burning operations have been completed.

(3) Prior to any of these operations, the fire watch shall have in their possession firefighting equipment in a usable condition.

(4) No welding or burning operation, other than approved hot tapping, shall be done on piping, containers, tanks, or other vessels which have contained a flammable substance unless the contents have been rendered inert and are determined to be safe for welding or burning by the designated person in charge.

(5) If drilling, well-completion, well-workover, or wireline operations are in progress, welding operations in other than approved safe-welding areas shall not be conducted unless the well(s) in the area where drilling, well-completion, well-workover, or wireline operations are in progress contain noncombustible fluids and the entry of formation hydrocarbons into the wellbore is precluded.

(6) If welding or burning operations are conducted in or within 10 feet of a well-bay or production area, all producing wells in the well-bay or production area shall be shut in at the surface safety valve.

§ 250.53 Electrical equipment.

The following requirements shall be applicable to all electrical equipment on all platforms, artificial islands, fixed structures, and their facilities:

(a) All engines with electrical ignition systems shall be equipped with a low-tension ignition system designed and maintained to minimize the release of sufficient electrical energy to cause ignition of an external, combustible mixture or substance.

(b) All areas shall be classified in accordance with API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities.

(c) All electrical installations shall be made in accordance with API RP 14F, Design and Installation of Electrical Systems for Offshore Production Platforms, except sections 7.4, Emergency Lighting and 9.4, Aids to Navigation Equipment.

(d) Maintenance of electrical systems shall be by personnel who are trained and experienced with the area classifications, distribution system, performance characteristics and operation of the equipment, and with the hazards involved.

[53 FR 10690, Apr. 1, 1988, as amended at 54 FR 50616, Dec. 8, 1989; 61 FR 60024, Nov. 26, 1996]

§ 250.54 Well casing and cementing.

(a) *General requirements.* (1) For the purpose of this subpart, the casing strings in order of normal installation are as follows:

(i) Drive or structural,

(ii) Conductor,

(iii) Surface,

(iv) Intermediate, and

(v) Production casing.

(2) The lessee shall case and cement all wells with a sufficient number of strings of casing and quantity and quality of cement in a manner necessary to prevent release of fluids from any stratum through the wellbore (directly or indirectly) into offshore waters, prevent communication between separate hydrocarbon-bearing strata, protect freshwater aquifers from contamination, support unconsolidated sediments, and otherwise provide a means of control of the formation pressures and fluids. Cement composition, placement techniques, and waiting time shall be designed and conducted so that the cement in place behind the bottom 500 feet of casing or total length of annular cement fill, if less,

attains a minimum compressive strength of 500 pounds per square inch (psi). Cement placed across permafrost zones shall be designed to set before freezing and have a low heat of hydration.

(3) The lessee shall install casing designed to withstand the anticipated stresses imposed by tensile, compressive, and buckling loads; burst and collapse pressures; thermal effects; and combinations thereof. Safety factors in the casing program design shall be of sufficient magnitude to provide well control during drilling and to assure safe operations for the life of the well. Any portion of an annulus opposite a permafrost zone which is not protected by cement shall be filled with a liquid which has a freezing point below the minimum permafrost temperature to prevent internal freezeback and which is treated to minimize corrosion.

(4) In cases where cement has filled the annular space back to the mud line, the cement may be washed out or displaced to a depth not exceeding the depth of the structural casing shoe to facilitate casing removal upon well abandonment if the District Supervisor determines that subsurface protection against damage to freshwater aquifers and permafrost zones and against damage caused by adverse loads, pressures, and fluid flows is not jeopardized.

(5) If there are indications of inadequate cementing (such as lost returns, cement channeling, or mechanical failure of equipment), the lessee shall evaluate the adequacy of the cementing operations by pressure testing the casing shoe, running a cement bond log, running a temperature survey, or a combination thereof before continuing operations. If the evaluation indicates inadequate cementing, the lessee shall re-cement or take other remedial actions as approved by the District Supervisor.

(6) A pressure-integrity test shall be run below the surface casing, the intermediate casing(s), and liner(s) used as intermediate casing(s). The District Supervisor may require a pressure-integrity test to be run at the conductor casing shoe due to local geologic conditions or planned casing setting depths. Pressure-integrity tests shall be made after drilling new hole below the casing shoe and before drilling more than 50 feet of new hole below a respective casing string. These tests shall be conducted either by testing to formation leak-off or by testing to a predetermined equivalent mud weight as specified in the approved APD. A safe margin, as approved by the District Supervisor, shall be maintained between the mud weight in use and the equivalent mud weight at the casing shoe as determined in the pressure-integrity test. Drilling operations shall be suspended when the safe margin is not maintained. Pressure-integrity and pore-pressure test results and related hole-behavior observations, such as gas-cut mud and well kicks made during the course of drilling, shall be used in adjusting the drilling mud program and the approved setting depth of the next casing string. The results of all tests and of hole-behavior observations made during the course of drilling related to formation integrity and pore pressure shall be recorded in the driller's report.

(b) *Drive or structural casing.* This casing shall be set by driving, jetting, or drilling to a minimum depth as may be prescribed or approved by the District Supervisor, in order to support unconsolidated deposits and to provide hole stability for initial drilling operations. If this portion of the hole is drilled, a quantity of cement sufficient to fill the annular space back to the mud line shall be used.

(c) *Conductor and surface casing requirements.* (1) *Conductor and surface casing setting depths.* Conductor and surface casing design and setting depths shall be based upon relevant engineering and geologic factors including the presence or absence of hydrocarbons, potential hazards, and water depths. The approved casing setting depths may be adjusted when the change is approved by the District Supervisor to permit the casing shoe to be set in a competent formation or below formations which should be isolated from the wellbore by casing for safer drilling operations. However, the conductor casing shall be set immediately prior to drilling into formations known to contain oil or gas or, if the presence of oil or gas is unknown, upon encountering a formation containing oil or gas. Upon encountering unexpected formation pressures, the lessee shall submit a revised casing program to the District Supervisor for approval. The District Supervisor may permit a lessee to drill a well without setting conductor casing provided the information from approved logging and mud-monitoring programs for wells previously drilled in the immediate vacinity combined with other available geologic data are sufficient to demonstrate the absence of shallow hydrocarbons or hazards.

(2) *Conductor casing cementing requirements.* Conductor casing shall be cemented with a quantity of cement that fills the calculated annular space back to the mud line except as applicable to the bottom of an excavation (glory hole) or to the surface of an artificial island. Cement fill in annular spaces shall be verified by the observation of cement returns. In the event that observation of cement returns is not feasible, additional quantities of cement shall be used to assure fill to the mud line.

(3) *Surface casing cementing requirements.* (i) Surface casing shall be cemented with a quantity of cement that fills the calculated annular space to at least 200 feet inside the conductor casing. When geologic conditions such as near-surface fractures and faulting exist, surface casing shall be cemented with a quantity of cement that fills the calculated annular space to the mud line, or as approved or prescribed by the District Supervisor.

(ii) For floating drilling operations, a lesser volume of cement may be used to prevent sealing the annular space between the conductor casing and surface casing if the District Supervisor determines that the uncemented space is necessary to provide protection from burst and collapse pressures which may be applied inadvertently to the annulus between casings during blowout preventer (BOP) testing operations. Any annular space open to the drilled hole shall be sealed in accordance with the requirements for abandonment in subpart G, Abandonment of Wells, of this part.

(d) *Intermediate casing requirements.* (1) Intermediate casing string(s) shall be set for protection when geologic characteristics or wellbore conditions, as anticipated or as encountered, so indicate.

(2) Quantities of cement that cover and isolate all hydrocarbon-bearing zones in the well and isolate abnormal pressure intervals from normal pressure intervals shall be used. This requirement for isolation may be satisfied by squeeze cementing prior to completion, suspension of operations, or abandonment, whichever occurs first. Sufficient cement shall be used to provide annular fill-up to a minimum of 500 feet above the zones to be isolated or 500 feet above the casing shoe in wells where zonal coverage is not required.

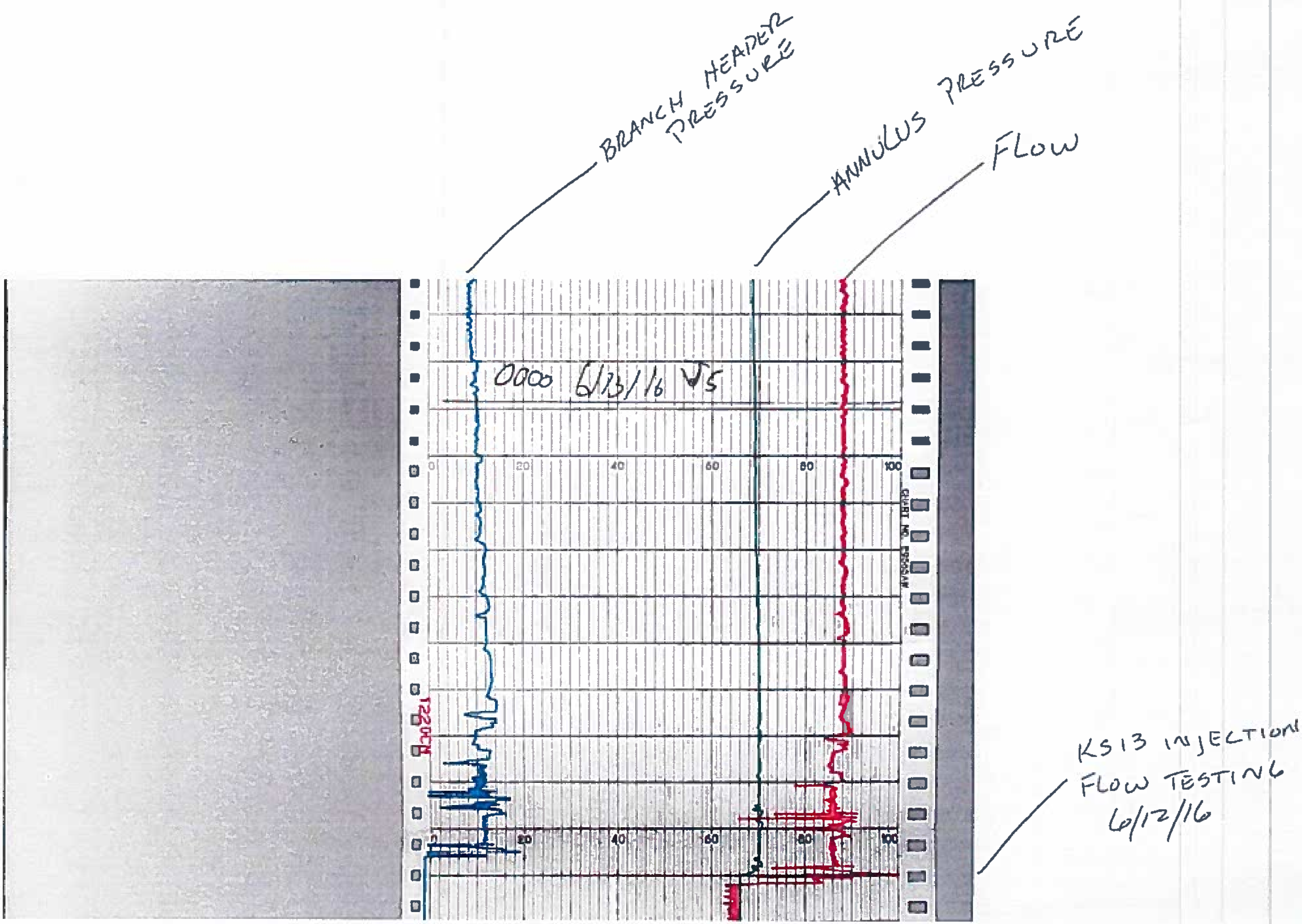
(3) If a liner is to be used as an intermediate string below a surface casing string, it shall be lapped a minimum of 100 feet into the previous casing string and cemented as required for intermediate casing. When a liner is to be used as production casing below a surface casing string, it shall be extended to the surface and cemented to avoid surface casing being used as production casing.

(e) *Production casing requirements.* (1) Production casing shall be cemented to cover or isolate all zones above the shoe which contain hydrocarbons; but in any case, a volume sufficient to fill the annular space at least 500 feet above the uppermost hydrocarbon-bearing zone shall be used.

(2) When a liner is to be used as production casing below intermediate casing, it shall be lapped a minimum of 100 feet into the previous casing string and cemented as required for the production casing.

§ 250.55 Pressure testing of casing.

(a) Prior to drilling the plug after cementing and in the cases of plugs in production casing strings and liners not planned to be subsequently drilled out, all casings, except the drive or structural casing, shall be pressure tested to 70 percent of the minimum internal-yield pressure of the casing or as otherwise approved or required by the District Supervisor. If the pressure declines more than 10 percent in 30 minutes or if there is another indication of a leak, the casing shall be recemented, repaired, or an additional casing string run and the casing pressure tested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KS13 INJECTION
FLOW TESTING
6/12/16

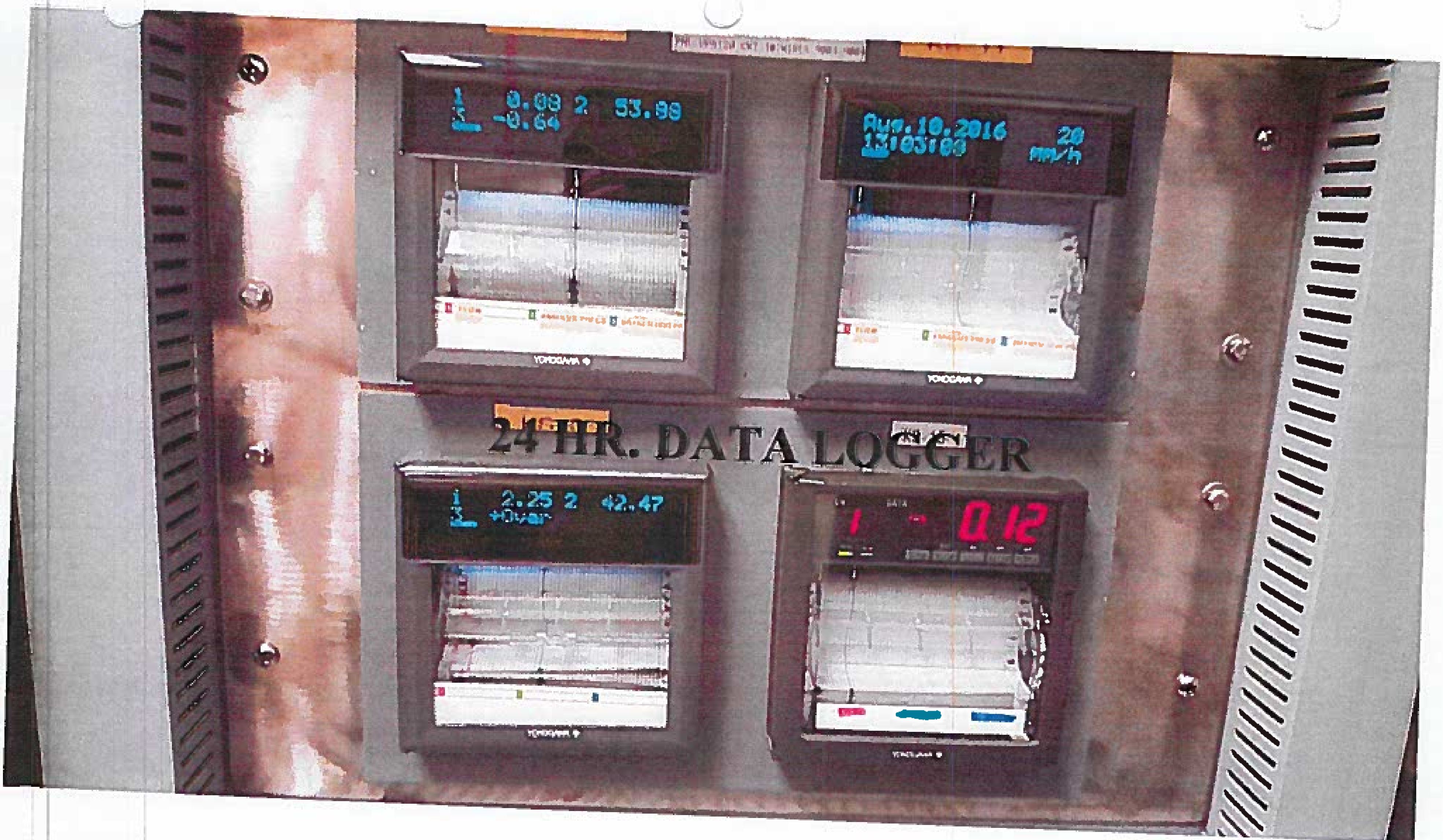
Location	Date	Prefix	Approved	Unit	Shift	Type	Gauge	Original Value
Puna	Jun 15 2016	I		KS-11	2	Injection	RJ Flow Rate	0
Puna	Jun 16 2016	I		KS-11	1	Injection	RJ Flow Rate	0
Puna	Jun 16 2016	I		KS-11	2	Injection	RJ Flow Rate	0
Puna	Jun 12 2016	I		KS-11	1	Injection	Wellhead PSI	378
Puna	Jun 12 2016	I		KS-11	2	Injection	Wellhead PSI	390
Puna	Jun 13 2016	I		KS-11	1	Injection	Wellhead PSI	320
Puna	Jun 13 2016	I		KS-11	2	Injection	Wellhead PSI	140
Puna	Jun 14 2016	I		KS-11	1	Injection	Wellhead PSI	100
Puna	Jun 14 2016	I		KS-11	2	Injection	Wellhead PSI	0
Puna	Jun 15 2016	I		KS-11	1	Injection	Wellhead PSI	0
Puna	Jun 15 2016	I		KS-11	2	Injection	Wellhead PSI	0
Puna	Jun 16 2016	I		KS-11	1	Injection	Wellhead PSI	0
Puna	Jun 16 2016	I		KS-11	2	Injection	Wellhead PSI	30
Puna	Jun 12 2016	I		KS-11	1	Injection	Wellhead Temp	158
Puna	Jun 12 2016	I		KS-11	2	Injection	Wellhead Temp	160
Puna	Jun 13 2016	I		KS-11	1	Injection	Wellhead Temp	160
Puna	Jun 13 2016	I		KS-11	2	Injection	Wellhead Temp	150
Puna	Jun 14 2016	I		KS-11	1	Injection	Wellhead Temp	160
Puna	Jun 14 2016	I		KS-11	2	Injection	Wellhead Temp	155
Puna	Jun 15 2016	I		KS-11	1	Injection	Wellhead Temp	175
Puna	Jun 15 2016	I		KS-11	2	Injection	Wellhead Temp	155
Puna	Jun 16 2016	I		KS-11	1	Injection	Wellhead Temp	100
Puna	Jun 16 2016	I		KS-11	2	Injection	Wellhead Temp	60
Puna	Jun 12 2016	I		KS-13	1	Injection	Annulus Pressure	53 START
Puna	Jun 12 2016	I		KS-13	2	Injection	Annulus Pressure	53

Location	Date	Prefix	Approved	Unit	Shift	Type	Gauge	Original Value
Puna	Jun 13 2016	I		KS-13	1	Injection	Annulus Pressure	65
Puna	Jun 13 2016	I		KS-13	2	Injection	Annulus Pressure	69
Puna	Jun 14 2016	I		KS-13	1	Injection	Annulus Pressure	67
Puna	Jun 14 2016	I		KS-13	2	Injection	Annulus Pressure	67
Puna	Jun 15 2016	I		KS-13	1	Injection	Annulus Pressure	69
Puna	Jun 15 2016	I		KS-13	2	Injection	Annulus Pressure	66
Puna	Jun 16 2016	I		KS-13	1	Injection	Annulus Pressure	69
Puna	Jun 16 2016	I		KS-13	2	Injection	Annulus Pressure	65
Puna	Jun 12 2016	I		KS-13	1	Injection	Daily Well Status	Off
Puna	Jun 12 2016	I		KS-13	2	Injection	Daily Well Status	Off
Puna	Jun 13 2016	I		KS-13	1	Injection	Daily Well Status	On
Puna	Jun 13 2016	I		KS-13	2	Injection	Daily Well Status	On
Puna	Jun 14 2016	I		KS-13	1	Injection	Daily Well Status	On
Puna	Jun 14 2016	I		KS-13	2	Injection	Daily Well Status	On
Puna	Jun 15 2016	I		KS-13	1	Injection	Daily Well Status	On
Puna	Jun 15 2016	I		KS-13	2	Injection	Daily Well Status	On
Puna	Jun 16 2016	I		KS-13	1	Injection	Daily Well Status	On
Puna	Jun 16 2016	I		KS-13	2	Injection	Daily Well Status	On
Puna	Jun 12 2016	I		KS-13	1	Injection	Geofluid Relief Valve PSI	0
Puna	Jun 12 2016	I		KS-13	2	Injection	Geofluid Relief Valve PSI	0
Puna	Jun 13 2016	I		KS-13	1	Injection	Geofluid Relief Valve PSI	0
Puna	Jun 13 2016	I		KS-13	2	Injection	Geofluid Relief Valve PSI	0
Puna	Jun 14 2016	I		KS-13	1	Injection	Geofluid Relief Valve PSI	0
Puna	Jun 14 2016	I		KS-13	2	Injection	Geofluid Relief Valve PSI	0
Puna	Jun 15 2016	I		KS-13	1	Injection	Geofluid Relief Valve PSI	0

Location	Date	Prefix	Approved	Unit	Shift	Type	Gauge	Original Value
Puna	Jun 15 2016	I		KS-13	2	Injection	Geofluid Relief Valve PSI	0
Puna	Jun 16 2016	I		KS-13	1	Injection	Geofluid Relief Valve PSI	0
Puna	Jun 16 2016	I		KS-13	2	Injection	Geofluid Relief Valve PSI	0
Puna	Jun 12 2016	I		KS-13	1	Injection	Hrs In Service	0
Puna	Jun 12 2016	I		KS-13	2	Injection	Hrs In Service	0
Puna	Jun 13 2016	I		KS-13	1	Injection	Hrs In Service	2
Puna	Jun 13 2016	I		KS-13	2	Injection	Hrs In Service	13
Puna	Jun 14 2016	I		KS-13	1	Injection	Hrs In Service	24
Puna	Jun 14 2016	I		KS-13	2	Injection	Hrs In Service	13
Puna	Jun 15 2016	I		KS-13	1	Injection	Hrs In Service	24
Puna	Jun 15 2016	I		KS-13	2	Injection	Hrs In Service	24
Puna	Jun 16 2016	I		KS-13	1	Injection	Hrs In Service	24
Puna	Jun 16 2016	I		KS-13	2	Injection	Hrs In Service	24
Puna	Jun 12 2016	I		KS-13	1	Injection	RJ Branch Hdr Press	1
Puna	Jun 12 2016	I		KS-13	2	Injection	RJ Branch Hdr Press	2
Puna	Jun 13 2016	I		KS-13	1	Injection	RJ Branch Hdr Press	0
Puna	Jun 13 2016	I		KS-13	2	Injection	RJ Branch Hdr Press	12
Puna	Jun 14 2016	I		KS-13	1	Injection	RJ Branch Hdr Press	0
Puna	Jun 14 2016	I		KS-13	2	Injection	RJ Branch Hdr Press	2
Puna	Jun 15 2016	I		KS-13	1	Injection	RJ Branch Hdr Press	1
Puna	Jun 15 2016	I		KS-13	2	Injection	RJ Branch Hdr Press	1
Puna	Jun 16 2016	I		KS-13	1	Injection	RJ Branch Hdr Press	0
Puna	Jun 16 2016	I		KS-13	2	Injection	RJ Branch Hdr Press	0
Puna	Jun 12 2016	I		KS-13	1	Injection	RJ Flow Rate	0
Puna	Jun 12 2016	I		KS-13	2	Injection	RJ Flow Rate	0

Location	Date	Prefix	Approved	Unit	Shift	Type	Gauge	Original Value
Puna	Jun 13 2016	i		KS-13	1	Injection	RJ Flow Rate	61
Puna	Jun 13 2016	i		KS-13	2	Injection	RJ Flow Rate	88
Puna	Jun 14 2016	i		KS-13	1	Injection	RJ Flow Rate	81
Puna	Jun 14 2016	i		KS-13	2	Injection	RJ Flow Rate	88
Puna	Jun 15 2016	i		KS-13	1	Injection	RJ Flow Rate	90
Puna	Jun 15 2016	i		KS-13	2	Injection	RJ Flow Rate	90
Puna	Jun 16 2016	i		KS-13	1	Injection	RJ Flow Rate	90
Puna	Jun 16 2016	i		KS-13	2	Injection	RJ Flow Rate	92
Puna	Jun 12 2016	i		KS-13	1	Injection	Wellhead PSI	0
Puna	Jun 12 2016	i		KS-13	2	Injection	Wellhead PSI	0
Puna	Jun 13 2016	i		KS-13	1	Injection	Wellhead PSI	0
Puna	Jun 13 2016	i		KS-13	2	Injection	Wellhead PSI	85
Puna	Jun 14 2016	i		KS-13	1	Injection	Wellhead PSI	0
Puna	Jun 14 2016	i		KS-13	2	Injection	Wellhead PSI	85
Puna	Jun 15 2016	i		KS-13	1	Injection	Wellhead PSI	0
Puna	Jun 15 2016	i		KS-13	2	Injection	Wellhead PSI	0
Puna	Jun 16 2016	i		KS-13	1	Injection	Wellhead PSI	6
Puna	Jun 16 2016	i		KS-13	2	Injection	Wellhead PSI	15
Puna	Jun 12 2016	i		KS-13	1	Injection	Wellhead Temp	76
Puna	Jun 12 2016	i		KS-13	2	Injection	Wellhead Temp	75
Puna	Jun 13 2016	i		KS-13	1	Injection	Wellhead Temp	200
Puna	Jun 13 2016	i		KS-13	2	Injection	Wellhead Temp	200
Puna	Jun 14 2016	i		KS-13	1	Injection	Wellhead Temp	200
Puna	Jun 14 2016	i		KS-13	2	Injection	Wellhead Temp	200
Puna	Jun 15 2016	i		KS-13	1	Injection	Wellhead Temp	203

Location	Date	Prefix	Approved	Unit	Shift	Type	Gauge	Original Value
Puna	Jun 15 2016	i		KS-13	2	Injection	Wellhead Temp	200
Puna	Jun 16 2016	i		KS-13	1	Injection	Wellhead Temp	208
Puna	Jun 16 2016	i		KS-13	2	Injection	Wellhead Temp	200
Puna	Jun 12 2016	p		KS-14	1	Production	Daily Well Status	On
Puna	Jun 12 2016	p		KS-14	2	Production	Daily Well Status	On
Puna	Jun 13 2016	p		KS-14	1	Production	Daily Well Status	On
Puna	Jun 13 2016	p		KS-14	2	Production	Daily Well Status	On
Puna	Jun 14 2016	p		KS-14	1	Production	Daily Well Status	On
Puna	Jun 14 2016	p		KS-14	2	Production	Daily Well Status	On
Puna	Jun 15 2016	p		KS-14	1	Production	Daily Well Status	On
Puna	Jun 15 2016	p		KS-14	2	Production	Daily Well Status	On
Puna	Jun 16 2016	p		KS-14	1	Production	Daily Well Status	On
Puna	Jun 16 2016	p		KS-14	2	Production	Daily Well Status	On
Puna	Jun 12 2016	p		KS-14	1	Production	East WHCV Disch Press	230
Puna	Jun 12 2016	p		KS-14	2	Production	East WHCV Disch Press	233
Puna	Jun 13 2016	p		KS-14	1	Production	East WHCV Disch Press	250
Puna	Jun 13 2016	p		KS-14	2	Production	East WHCV Disch Press	233
Puna	Jun 14 2016	p		KS-14	1	Production	East WHCV Disch Press	230
Puna	Jun 14 2016	p		KS-14	2	Production	East WHCV Disch Press	233
Puna	Jun 15 2016	p		KS-14	1	Production	East WHCV Disch Press	250
Puna	Jun 15 2016	p		KS-14	2	Production	East WHCV Disch Press	230
Puna	Jun 16 2016	p		KS-14	1	Production	East WHCV Disch Press	230
Puna	Jun 16 2016	p		KS-14	2	Production	East WHCV Disch Press	230
Puna	Jun 12 2016	p		KS-14	1	Production	East WHCV Hyd Press	2500
Puna	Jun 12 2016	p		KS-14	2	Production	East WHCV Hyd Press	2600



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TITLE: Mechanical Integrity Testing

Revision #: 0
Date of Current Rev:
By: GD
Last Rev: 10/14/10

Procedure Mechanical Integrity Testing

Possible means of proving mechanical integrity of a geothermal well:

1. Make a sinker bar run using a sinker bar with a larger o.d. than p/t tools.
   a. Run In Hole (RIH) to ~ 3000' to insure that well bore is open.
   b. RIH @ a slow rate ~ 60'/min. to minimize the chance of getting hung up.

2. Perform pressure temperature (p/t) survey to desired depth ~3000'.
   a. This will determine static fluid level in the well bore.
   b. This will also identify bottom hole temperatures and pressures.
   c. A second static survey will verify if abnormal conditions exist, such as fluid communication outside the casing or unusual thermal recovery after injection is stopped.

3. Perform Nitrogen (N2) pressure test on well bore casing.
   a. Calculate pressure needed to depress fluid to 3000'.
   b. Use pressure gauge and chart recorder to monitor pressure losses.
   c. Pressurize well bore with N2 in 500 psi increments. Hold each 30 min.
   d. When calculated pressure is achieved hold for at least 5hrs.
   e. Check all surface equipment for leaks during this evolution.

1A. Schedule for running MIT's
   a. Start in hole with enough time to make stops prior to well shut-in
   b. Wait on bottom 90 minutes after shut-in, POH running 1st static log
   c. Run 2nd log 12 hours after shut-in

Note: If the above tests pass satisfactorily it may be considered by some to have acceptable integrity. If not additional testing could possibly be as follows but not limited to.

4. RIH with a gauge ring and allow ~ 1" clearance to Inner Diameter (ID) of casing.

5. RIH with a multi finger caliper to desired depth and log ID of casing while Pulling Out Of Hole (POOH).

6. Run a Bond Log to ensure the cement on the back side of the casing has good integrity. Note: Bottom hole temperatures must be within the ratings of tools.

7. Additional logging may be performed to obtain further information if so desired.

Note: For all logging evolutions refer to the P.G.V. procedure for "Logging Wells"

APPENDIX B

PUNA GEOTHERMAL VENTURE
PROGRAM FOR MECHANICAL INTEGRITY TESTING AND MONITORING OF INJECTION WELLS

1. INTRODUCTION

1.1 Background

Pursuant to Underground Injection Control (UIC) Permit No. HI596002, the U.S. Environmental Protection Agency requires that Puna Geothermal Venture (PGV) comply with this Testing and Monitoring Program (TMP) for injection wells. Monitoring and testing provisions in this TMP are similar in most respects to those in the "Casing Monitoring Program," April 26, 1993 version, which is referenced by title in PGV's current UIC Permit No. UH-1529. **(The Casing Monitoring Program related to Hawaii UIC Permit No. UH-1529 was originally dated 11/21/1991 and amended later dated 4/26/1993.)** It is anticipated that this same TMP will be approved and adopted by the Hawaii Department of Health as a replacement for the 1993 "Casing Monitoring Program." Revisions to testing and monitoring provisions in the 1993 "Casing Monitoring Program" have been made as a result of a joint review of PGV's injection well monitoring and testing involving EPA, BLM (as advisor to EPA), HDOH and PGV. The purpose of these revisions is to better accomplish the goal of protecting the groundwater aquifer under the PGV project site, which is considered to be a USDW. The principle changes in the monitoring and testing procedures are as follows:

- As described in Section 3.1 of this TMP for wells in injection service, the annulus nitrogen pressure will be maintained to keep the nitrogen/water interface at a depth of at least 2000 ft.

The 1993 CMP requires that the nitrogen/water interface be maintained "more than half way down the annulus." Based on a nominal casing depth of 4000 ft., the two criteria are effectively the same.

- In accordance with Section 3.2.1, the annual casing pressure test of each well will be done by depressing the water level to 3000 ft. with nitrogen while the well is on injection. Annulus pressure drop exceeding 10% in five hours will be considered indicative of a leak requiring diagnosis and repair.

  The 1993 CMP specifies that the pressure test be done by depressing the water level to the shoe of the 9-5/8-inch casing with nitrogen (while, by practical necessity, the well is shut in.). An annulus pressure drop exceeding 8% in 30 minutes was considered indicative of a leak requiring diagnosis and repair. The principle difference is the increase in length of the test period from 30 minutes to five hours, which makes the nitrogen pressure test equivalent to a 30-minute test with water.

1.2 Purpose

The purpose of this TMP is to specify the observations, tests, drilling operations and , if necessary, remedial actions required to insure that the mechanical integrity of injection well casing and cement is maintained through the drilling, testing and operation of PGV wells. The cemented and hung casing strings that are used in the PGV wells are designed to prevent contamination of any underground source of drinking water (USDW) by injected fluids. Contamination of the USDW's might occur if the casing strings are breached due to corrosion or mechanical failure or if there is a failure of the cement to seal the casing/borehole annulus between the casing shoe and the lowermost USDW. The testing and monitoring program described below is designed to detect and diagnose a loss of mechanical integrity in the casing or cement.

Remedial actions required to restore mechanical integrity are also described.

1.3 Scope

This TMP covers all injection wells on the 500-acre PGV site.

2. TESTING DURING DRILLING AND COMPLETION

2.1 Pressure Testing During Drilling

Each injection well is completed with three casing strings (not including the 30-inch conductor pipe) cemented to the surface (Figure 1). Upon completion of cementing each casing string and prior to drilling out the cement shoe, the casing well be pressure tested. The DLNR will be notified at least 24 hours before each test for the opportunity to witness it. The test will consist of pressurizing the casing with water or drilling mud to a specified test pressure and monitoring the pressure for 30 minutes with the well shut-in. The minimum casing test pressure shall be approximately one-third of the internal yield pressure rating, provided that the test pressure shall not be less than 600 psig nor greater than 2500 psig. In cases where combination strings or liners are involved, the above test pressures shall apply to the lowest pressure-rated casing. The pressure drop during the 30-minute period shall not exceed 10% of the test pressure.

In the event of a pressure loss exceeding the above criterion, one or more of the following diagnostic methods will be used to locate the leak:

- Temperature log while injecting
- Shut-in temperature survey
- Casing inspection logs with multi-arm caliper and/or magnetic inspection tools
- Pressure testing with a packer(s) on drillpipe
- Other applicable methods

After identification of the point of leakage, a cement squeeze job will be performed and the casing retested.

After a successful pressure test of each casing string, drilling will proceed to a point at least one foot below the casing shoe, and a pressure leak-off test will be performed to test the integrity of the annular cement. Each test will be performed at a pressure approaching the fracturing pressure of the exposed formation. If there is excessive leak-off, a squeeze cement job will be performed, the cement will be drilled out and the test will be repeated. Drilling will not proceed until an effective cement seal is established in the casing/borehole annulus above the casing shoe. In some situations, such as the case where there is natural formation permeability immediately below the casing shoe, it may not be practical to prove cement integrity with the pressure test described above. As an alternative, a standard water shutoff test (WSO) may be done above the shoe, or shut-in temperature surveys may be run.

2.2 Logs and Surveys During Injection Testing

Upon completion of drilling and prior to installation of the hangdown liner, a water injection test may be performed, if needed, to obtain a preliminary evaluation of the well. During such a test, one or more of the following logs or surveys may be run:

- TPS or T/P logs through the open hole and cased intervals with the well on injection; or

- Shut-in temperature survey(s) before and/or after injection.

If any of these logs or surveys indicates a loss of mechanical integrity, the problem will be diagnosed, and repair procedures will be performed in accordance with Section 2.3.

2.3 Casing Repair

Once a loss of mechanical integrity is identified and approximately located, casing repair procedures will be initiated. These procedures may include any or all of the following activities:

2.3.1 Shut in well and run magnetic and multi-arm casing inspection logging tools to locate the leak and to evaluate the casing condition.

2.3.2 Rig up workover rig on well. Run packer(s) on drillpipe and pressure test to confirm suspected leaking interval.

2.3.3 Execute cement squeeze job to seal casing leak or stop interzonal flows behind casing.

2.3.4 Perform casing pressure test and other diagnostic tests as necessary to confirm success of the remedial work. If good, move rig off well and return well to injection service.

2.3.5 In the event of major casing failure, a cemented liner may be installed through the damaged interval.

2.3.6 Prior to drilling out the liner shoe, the liner will be pressure tested as described in Section 2.1.

2.3.7 If mechanical integrity cannot be restored satisfactorily, the well will be plugged and abandoned.

3. <u>MONITORING AND TESTING AFTER WELL IS PLACED IN SERVICE</u>

3.1 Continuous Monitoring During Routine Injection Operations

During routine injection well operations, including brief periods when well(s) may be temporarily out of service, the following conditions will be maintained:

3.1.1 A continuous recording of the following parameters will be maintained for each well:

- Injection wellhead pressure,
- Annulus (nitrogen) pressure, and
- Injection flow rate.

These parameters shall be recorded on a graphical chart which shows their relationship to elapsed time. Plant operators will take daily readings at each well.

3.1.2 The annular space between the hangdown liner and cemented casing will be pressurized with nitrogen, and the pressure will be monitored and recorded in accordance with Section 3..1. above. The annulus will be repressurized with nitrogen as necessary to maintain the nitrogen/water interface at a depth of 2000 ft KB (1975 ft below ground level) or deeper. some loss of nitrogen pressure is normal, and occasional repressurization will be required. If the rate of nitrogen pressure decline is such that it is impractical to maintain the required minimum pressure, it will be considered indicative of a leak requiring diagnosis and repair.

3.2 Annual Testing

Once annually, tests and surveys will be conducted to verify mechanical integrity of the hangdown liner. The casing and hangdown liner will be tested for leaks by one of the following procedures, or a combination thereof.

3.2.1 Perform a pump-down test on the annulus between the hangdown liner and the cemented casing. The test will be done with the well on injection at normal operating flow rate and wellhead pressure, or higher.

<u>or</u>

3.2.2 If the hangdown liner is pulled, the casing may be pressure tested above a bridge plug or packer set near the shoe following the basic procedure outlined in Section 2.1. Integrity of the hangdown liner may be verified by inspection on the surface, by a pressure test (with nitrogen) after it is run in the hole, or by a TPS log with the well on injection.

Integrity of the cement (external mechanical integrity) will be checked during each workover by one or more of the following procedures:

3.2.3 One or more shut-in static temperature surveys will be run. Shut-in time will be at least 12 hours, or longer if necessary to obtain meaningful results.

or

3.2.4 Other logs or surveys may be run, at the discretion of PGV, if static temperature surveys are not definitive.

3.3 Restoration of Mechanical Integrity or Abandonment

In the event that the diagnostic procedures indicate a loss of mechanical integrity, remedial or abandonment procedures will be carried out as specified in Section 2.3.

ATTACHMENT P – MONITORING PROGRAM

The existing environmental monitoring program associated with the injection of geothermal fluids at the PGV site consists of monitoring groundwater, injectate, and mechanical integrity. The current groundwater monitoring program is described in the document titled Appendix A, Puna Geothermal Venture Hydrologic Monitoring Program.

PGV's current casing monitoring program is described in Appendix B, Program for Mechanical Integrity Testing and Monitoring of Injection Wells.

Table 1 consists of chemical additives that have been approved by the EPA and HDOH for injection. Tables 2, 3, and 4 are parameters tested for Type I, III, and IV sampling, respectively.

All of the Appendices and Tables in Attachment P are included in the existing State of Hawaii UIC Permit No. UH-1529.

Figure B-1 in Attachment B is a map of the Area of Review showing the location of monitoring wells.

ATTACHMENT Q – PLUGGING AND ABANDONMENT PLAN

A detailed description of the proposed plugging and abandonment plan for KS-1A, KS-3, KS-11, KS-13, KS-15, KS-17, KS-18, KS-19, KS-20, KS-21, KS-22, KS-23, KS-24, KS-25, KS-26 and KS-27 are included in Attachment Q-1. This plugging and abandonment plan is consistent with requirements associated with the permit from the State of Hawaii Board of Land and Natural Resources to construct the wells.

PUNA
GEOTHERMAL
VENTURE
An ORMAT Company

August 28, 2019

Mr. Joel Coffman
U.S. Environmental Protection Agency, Region IX
Ground Water Office (WTR-9)
75 Hawthorne Street
San Francisco, CA. 94105-3901

SUBJECT: FINANCIAL RESPONSIBILITY

Dear Mr. Coffman:

Pursuant to Puna Geothermal Venture's (PGV's) Federal UIC Permit HI 596002, Part II. G.1., PGV hereby submits updated information regarding financial responsibility and resources to close, plug and abandon all five of our injection wells.

PGV has included a detailed P&A plan with an updated cost estimate of $2,151,360 to the EPA.

P&A Estimates as of August 2019:

KS-1A	$373,000.00
KS-3	$373,000.00
KS-11	$393,000.00
KS-13	$424,000.00
KS-15RD	$408,825.00
Rig and cementing equipment mobilization, program and engineering cost.	$179.535.00
Total	$2,151,360.00

Pursuant to EPA policy, the Letter of Credit (LOC) shows total amount of $6,454,080, which multiplies the P&A cost by a factor of three (3). Attached please find a revised Standby Trust Agreement dated November 3, 2009 (confirmed as still valid in 2019), Exhibit A form, Schedule A form and the updated LOC.

Should you have any questions, please feel free to call me at (808) 896-8551 or Ron Quesada at (808) 430-8679.

Sincerely,

Jordan Hara
Plant Manager

Enclosures: Amendment to Standby Trust Agreement dated November 3, 2009
Updated Letter of Credit
Detailed Plan of Procedure for P&A for your review
EPA Form 7520-14 for all five injection wells at PGV

cc: Norris Uehara, DOH
Eric Tanaka, DLNR
Paul Spielman, PGV
PGV File

We certify that this document and all attachments are true, accurate, and complete, pursuant to HAR 11-60.1-4.

PUNA GEOTHERMAL VENTURE
14-3860 Kapoho Pahoa Road, Pahoa, HI 96778-0030, USA • +1-808-965-6233 • ormat@ormat.com ormat.com

July 13, 2015

Via Electronic Mail

Sonia Flores
MUFG Union Bank, N.A.
475 Sansome Street, 12th Floor
San Francisco, CA 94111

David Albright
U.S. Environmental Protection Agency, Region 9
Ground Water Office (WTR-9)
75 Hawthorne Street
San Francisco, CA 94105

RE: Amendment to Standby Trust Agreement dated November 3, 2009

Dear All,

Puna Geothermal Venture (PGV) desires to amend the Standby Trust Agreement dated as of November 3, 2009 (the "Agreement"), by and between PGV, the "Grantor", and Union Bank of California (UBOC), the "Trustee".

This letter serves under Section 16 of the Agreement as the written consent of the Grantor, the Trustee, and the EPA Regional Administrator to amend the Agreement.

PGV has recently converted a production well, designated KS-15, into an injection well, and pursuant to EPA requirements the cost to plug and abandon (P&A) must be covered under the existing Fund. PGV has submitted a detailed P&A plan with and updated cost estimate of $2,151,360 to the EPA, which has been accepted.

Pursuant to EPA policy, the current letter of credit will be increased to an amount of $6,454,080, which multiplies the P&A cost by a factor of three (3). Attached please find a revised Schedule A and the updated letter of credit.

PGV has also revised Exhibit A to update the Authorized Persons.

Please signify your consent to the proposed amendment of the Agreement pursuant to Section 16 by signing below.

Thank you for your consideration of this matter.

Connie Stechman

Connie Stechman
Vice President of Finance
Ormat Technologies, Inc.

Approved By:

GRANTOR:

By: Connie Stechman

Connie Stechman

Its: Assistant Secretary

TRUSTEE

By: ______________________

____

Its: ______________________

U.S. ENVIRONMENTAL PROTECTION AGENCY

By: ______________________

____

Its: ______________________

EXHIBIT A

AUTHORIZED PERSONS FOR STANDBY TRUST AGREEMENT

Name	Title
Isaac Angel	**CEO**
Doron Blachar	**CFO**
Connie Stechman	**Assistant Secretary**

SCHEDULE A

Identification of Facilities and Cost Estimates

Schedule A is referenced in the Standby Trust Agreement dated November 3, 2009, by and between Puna Geothermal Venture, the "Grantor" and MUFG Union Bank, N.A. (f/k/a Union Bank, N.A.), the "Trustee".

EPA Identification Number	100000091599
Name of Facility	Puna Geothermal Venture
Address of Facility	P.O. Box 30 14-3860 Kapoho Pahoa Rd.
Current Plugging and Abandonment Cost Estimate	$2,151,360
Date of Estimate	July, 1 2015

בנק הפועלים bank hapoalim

המרכז לסחר בינלאומי   תאריך: 10.07.15

לכבוד
אורמת תעשיות בע"מ
ת.ד. 68
יבנה 81100

סניף מרכזי-עסקים 600
(תיבת דואר בסניף מספר: 000019)

הנדון: ערבות מס. 600-02-001885-0

```
************************************************************
* להלן נוסח תיקון הערבות שנשלחה לבקשתכם לחו"ל בהודעה אלקטרונית*
*          אנו,בבנק הפועלים,נשמח לעמוד לשרותכם בכל עת.          *
*          המחלקה לעסקי סחר חוץ-מדור ערבויות:03-7146507          *
************************************************************
```

{2:I767 SCBLUS33 N}
{3:{108: 600-02-001885-0 }}
{4:
TO: STANDARD CHARTERED BANK
1095 AVENUE OF THE AMERICAS
NEW YORK, NY 10036
U.S.A.

SENDER: BANK HAPOALIM B.M.
:27: SEQUENCE OF TOTAL DATE: 10 JULY,2015
1/1
:20: TRANSACTION REFERENCE NUMBER
600-02-001885-0
:21: RELATED REFERENCE NUMBER
777520069275
:23: FURTHER IDENTIFICATION
REQUEST
:31C: DATE OF ISSUE OR REQUEST TO ISSUE
040714
:77C: AMENDMENT DETAILS
VERY URGENT

ATT: GUARANTEE DEPT.

YR REF: 777020010882

RE: OUR STANDBY L/C NO. 600-02-001885/0
FOR THE BALANCED AMOUNT OF USD 1,761,000.-
ISSUED ON JULY 14, 2004
COVERING YOUR STANDBY L/C IN FAVOUR OF
U.S. ENVIRONMENTAL PROTECTION AGENCY

AT THE REQUEST OF OUR CUSTOMER,
WE HEREBY REQUEST YOU TO INCREASE THE AMOUNT OF
YOUR A.M. STANDBY L/C BY THE AMOUNT OF
USD 4,693,080.- (US DOLLARS FOUR MILLION SIX
HUNDRED NINETY THREE THOUSAND AND EIGHTY)

ט.ל.ח.

DEAL NUMBER : 600-02-001885-0

TO A NEW TOTAL AMOUNT OF USD 6,454,080.-
(US DOLLARS SIX MILLION FOUR HUNDRED FIFTY FOUR
THOUSAND EIGHTY).

ACCORDINGLY, WE HEREBY INCREASE THE AMOUNT OF
OUR A.M. STANDBY L/C ISSUED IN YOUR FAVOUR BY
THE AMOUNT OF USD 4,693,080.- (US DOLLARS
FOUR MILLION SIX HUNDRED NINETY THREE THOUSAND
AND EIGHTY) TO A NEW TOTAL INCREASED AMOUNT OF
USD 6,454,080.- (US DOLLARS SIX MILLION FOUR
HUNDRED FIFTY FOUR THOUSAND EIGHTY).

ALL OTHER TERMS AND CONDITIONS OF YOUR STANDBY L/C
AND OF OUR STANDBY L/C IN YOUR FAVOUR,
REMAIN VALID AND UNCHANGED.

BEST REGARDS,
BANK HAPOALIM B.M.
INTERNATIONAL TRADE CENTER

מספרכם 48895

בכבוד רב,
בנק הפועלים בע"מ
המרכז לסחר בינלאומי

ט.ל.ח.
המרכז לסחר בינלאומי ת.ד: 27 תל אביב טלפון: 03-7146300 פקס:
037146367 (טופס מס. AMD018 A1 BV28 MT767)

Detailed Plan of Procedure for Plugging and Abandoning Injection Wells at the Puna Geothermal Venture Facility
JFH 28Aug19

Assumptions:

- All five (5) injection wells would be abandoned at the same time. Work would be performed in series, one well at a time.
- Work would be accomplished utilizing PGV Rig 1.

Procedure for each individual well:

1. Mobilize rig to location, in parallel with site preparation.
2. Nipple up Blow Out prevention Equipment.
3. If needed, kill well with plant water.
4. Pull and remove hang down liner.
5. Pick up drill pipe and run in hole to set bottom plug.
6. Set plugs as per EPA Plugging and Abandonment Plan Form 7520-14.
7. Salvage surface equipment, primarily wellhead components.
8. Cut off casing.
9. Reclaim and restore location
10. Move to next well.
11. De-mob Rig after completion of last well to be plugged and abandoned.

OMB No. 2040-0042 Approval Expires 12/31/2011

EPA

United States Environmental Protection Agency
Washington, DC 20460

PLUGGING AND ABANDONMENT PLAN

Name and Address of Facility	Name and Address of Owner/Operator
Puna Geothermal Venture 14-3860 Kapoho Pahoa Road, Pahoa, HI 96778	Puna Geothermal Venture PO Box 30, Pahoa, HI 96778

Locate Well and Outline Unit on Section Plat - 640 Acres

N

W E

S

State	County	Permit Number
HI	Hawaii	

Surface Location Description

n/a 1/4 of n/a 1/4 of n/a 1/4 of n/a 1/4 of Section n/a Township n/a Range n/a

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface 8902.9 ft. N and 9919.0 ft E of Kaliu Benchmark

Location ___ ft. frm (N/S) ___ Line of quarter section

and ___ ft. from (E/W) ___ Line of quarter section.

TYPE OF AUTHORIZATION

- [ ] Individual Permit
- [x] Area Permit
- [ ] Rule

Number of Wells 1

Lease Name Kapoho State

WELL ACTIVITY

- [ ] CLASS I
- [ ] CLASS II
  - [x] Brine Disposal
  - [ ] Enhanced Recovery
  - [ ] Hydrocarbon Storage
- [ ] CLASS III

Well Number 1A

CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT (LB/FT)	TO BE PUT IN WELL (FT)	TO BE LEFT IN WELL (FT)	HOLE SIZE
20	94'		0-1376	26"
13 3/8	61		0-2200	17 1/2"
9 5/8	47		0-4061	12 1/4
7	26 & 29	3895-6505	0-3510	8 1/2

METHOD OF EMPLACEMENT OF CEMENT PLUGS

- [x] The Balance Method
- [ ] The Dump Bailer Method
- [ ] The Two-Plug Method
- [ ] Other

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7
Size of Hole or Pipe in which Plug Will Be Placed (inche	6.2/8.6	8.6	6.184	6.184	6.184	6.184	
Depth to Bottom of Tubing or Drill Pipe (ft	4000	3750	3500	2500	1500	Redimix	
Sacks of Cement To Be Used (each plug)	61	63	128	128	160	32	
Slurry Volume To Be Pumped (cu. ft.)	100	103	208	208	260	52	
Calculated Top of Plug (ft.)	3750	3500	2500	1500	250	0	
Measured Top of Plug (if tagged ft.)							
Slurry Wt. (Lb./Gal.)	15.5	15.5	15.5	15.5	15.5	15.5	
Type Cement or Other Material (Class III)							

LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS AND INTERVALS WHERE CASING WILL BE VARIED (if any)

From	To	From	To
4061	6505	Slotted liner	
0	3318	Hang down liner (removing)	

Estimated Cost to Plug Wells

$373,000.00

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title *(Please type or print)*	Signature	Date Signed
Jordan Hara, Plant Manager		08/28/2019

EPA Form 7520-14 (Rev. 12-08)

*Depth of first plug may be revised if wellbore is obstructed
**Range of costs is a function of rig usage

Paperwork Reduction Act Notice

The public reporting and record keeping burden for this collection of information is estimated to average 4.5 hours for operators of Class I hazardous wells, 1.5 hours for operators of Class I non-hazardous wells, 3 hours for operators of Class II wells, and 1.5 hours for operators of Class III wells.
Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to the collection of information; search data sources; complete and review the collection of information; and, transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR Part 9 and 48 CFR Chapter 15.
Please send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques to Director, Office of Environmental Information, Collection Strategies Division, U.S. Environmental Protection Agency (2822), Ariel Rios Building, 1200 Pennsylvania Ave., NW., Washington, DC 20460; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, Attention: Desk Officer for EPA. Please include the EPA ICR number and OMB control number in any correspondence.

OMB No. 2040-0042 Approval Expires 12/31/2011

EPA

United States Environmental Protection Agency
Washington, DC 20460

PLUGGING AND ABANDONMENT PLAN

Name and Address of Facility	Name and Address of Owner/Operator
Puna Geothermal Venture 14-3860 Kapoho Pahoa Road, Pahoa, HI 96778	Puna Geothermal Venture PO Box 30, Pahoa, HI 96778

Locate Well and Outline Unit on Section Plat - 640 Acres

N W E S

State	County	Permit Number
HI	Hawaii	

Surface Location Description

n/a 1/4 of n/a 1/4 of n/a 1/4 of n/a 1/4 of Section n/a Township n/a Range n/a

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface 8317.9 ft. N and 9430.2 ft E of Kaliu Benchmark

Location ___ ft. frm (N/S) ___ Line of quarter section

and ___ ft. from (E/W) ___ Line of quarter section.

TYPE OF AUTHORIZATION

- [ ] Individual Permit
- [x] Area Permit
- [ ] Rule

Number of Wells 1

Lease Name Kapoho State

WELL ACTIVITY

- [ ] CLASS I
- [ ] CLASS II
  - [x] Brine Disposal
  - [ ] Enhanced Recovery
  - [ ] Hydrocarbon Storage
- [ ] CLASS III

Well Number 3

CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT (LB/FT)	TO BE PUT IN WELL (FT)	TO BE LEFT IN WELL (FT)	HOLE SIZE
20	94		0-1030	26"
13 3/8	61		0-2209	17 1/2
9 5/8	47		0-3897	12/1/4
7	29	3767-6835	0-3704	8 1/2

METHOD OF EMPLACEMENT OF CEMENT PLUGS

- [x] The Balance Method
- [ ] The Dump Bailer Method
- [ ] The Two-Plug Method
- [ ] Other

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7
Size of Hole or Pipe in which Plug Will Be Placed (inche	6.2/8.6	6.184	6.184	6.184	6.184	6.184	
Depth to Bottom of Tubing or Drill Pipe (ft	3850	3600	3350	2350	1350	Redimix	
Sacks of Cement To Be Used (each plug)	37	32	129	129	142	32	
Slurry Volume To Be Pumped (cu. ft.)	61	52	210	210	230	52	
Calculated Top of Plug (ft.)	3600	3350	2350	1350	250	0	
Measured Top of Plug (if tagged ft.)							
Slurry Wt. (Lb./Gal.)							
Type Cement or Other Material (Class III)							

LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS AND INTERVALS WHERE CASING WILL BE VARIED (if any)

From	To	From	To
6835	7406	Open Hole	
3897	6835	Slotted liner	
0	3321	Hang down(removing)	

Estimated Cost to Plug Wells

$373,000.00

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title *(Please type or print)*	Signature	Date Signed
Jordan Hara, Plant Manager	[signature]	08/28/2019

EPA Form 7520-14 (Rev. 12-08)

*Depth of first plug may be revised if wellbore is obstructed
**Range of costs is a function of rig usage

Paperwork Reduction Act Notice

The public reporting and record keeping burden for this collection of information is estimated to average 4.5 hours for operators of Class I hazardous wells, 1.5 hours for operators of Class I non-hazardous wells, 3 hours for operators of Class II wells, and 1.5 hours for operators of Class III wells.
Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to the collection of information; search data sources; complete and review the collection of information; and, transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR Part 9 and 48 CFR Chapter 15.
Please send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques to Director, Office of Environmental Information, Collection Strategies Division, U.S. Environmental Protection Agency (2822), Ariel Rios Building, 1200 Pennsylvania Ave., NW., Washington, DC 20460; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, Attention: Desk Officer for EPA. Please include the EPA ICR number and OMB control number in any correspondence.

OMB No. 2040-0042 Approval Expires 12/31/2011

EPA

United States Environmental Protection Agency
Washington, DC 20460

PLUGGING AND ABANDONMENT PLAN

Name and Address of Facility
Puna Geothermal Venture
14-3860 Kapoho Pahoa Road, Pahoa, HI 96778

Name and Address of Owner/Operator
Puna Geothermal Venture
PO Box 30, Pahoa, HI 96778

Locate Well and Outline Unit on Section Plat - 640 Acres

N / W / E / S

State: HI
County: Hawaii
Permit Number:

Surface Location Descriptior
n/a 1/4 of n/a 1/4 of n/a 1/4 of n/a 1/4 of Section n/a Township n/a Range n/a

Locate well in two directions from nearest lines of quarter section and drilling unit
Surface 8879.72 ft. N and 9601.32 ft E of Kaliu Benchmark
Location ___ ft. frm (N/S) ___ Line of quarter section
and ___ ft. from (E/W) ___ Line of quarter section.

TYPE OF AUTHORIZATION
- [ ] Individual Permit
- [x] Area Permit
- [ ] Rule

Number of Wells 1

Lease Name Kapoho State

WELL ACTIVITY
- [ ] CLASS I
- [ ] CLASS II
  - [x] Brine Disposal
  - [ ] Enhanced Recovery
  - [ ] Hydrocarbon Storage
- [ ] CLASS III

Well Number 11

CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT (LB/FT)	TO BE PUT IN WELL (FT)	TO BE LEFT IN WELL (FT)	HOLE SIZE
22	106.5		0-1002	26"
16	97		0-2102	20"
11 3/4	65		0-4367	14 3/4"
9 5/8	47		0-3290	10 5/8"

METHOD OF EMPLACEMENT OF CEMENT PLUGS
- [x] The Balance Method
- [ ] The Dump Bailer Method
- [ ] The Two-Plug Method
- [ ] Other

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7
Size of Hole or Pipe in which Plug Will Be Placed (inche	6.366	6.366	6.36/8.6	8.68	8.68	8.68	8.68
Depth to Bottom of Tubing or Drill Pipe (ft	4500	4300	4000	3000	2000	1000	Redimix
Sacks of Cement To Be Used (each plug)	27	41	156	252	252	190	65
Slurry Volume To Be Pumped (cu. ft.)	44	66	255	411	411	308	103
Calculated Top of Plug (ft.)	4300	4000	3000	2000	1000	250	0
Measured Top of Plug (if tagged ft.)							
Slurry Wt. (Lb./Gal.)							
Type Cement or Other Material (Class III)							Neat

LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS AND INTERVALS WHERE CASING WILL BE VARIED (if any)

From	To	From	To
4873	5861	Perforated liner	
5861	6872	Open hole	
0	3142	Hang down (removing)	

Estimated Cost to Plug Wells
$393,000

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title *(Please type or print)*	Signature	Date Signed
Jordan Hara, Plant Manager		08/28/2019

EPA Form 7520-14 (Rev. 12-08)

*Depth of first plug may be revised if wellbore is obstructed
**Range of costs is a function of rig usage

Paperwork Reduction Act Notice

The public reporting and record keeping burden for this collection of information is estimated to average 4.5 hours for operators of Class I hazardous wells, 1.5 hours for operators of Class I non-hazardous wells, 3 hours for operators of Class II wells, and 1.5 hours for operators of Class III wells.
Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to the collection of information; search data sources; complete and review the collection of information; and, transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR Part 9 and 48 CFR Chapter 15.
Please send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques to Director, Office of Environmental Information, Collection Strategies Division, U.S. Environmental Protection Agency (2822), Ariel Rios Building, 1200 Pennsylvania Ave., NW., Washington, DC 20460; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, Attention: Desk Officer for EPA. Please include the EPA ICR number and OMB control number in any correspondence.

OMB No. 2040-0042 Approval Expires 12/31/2011

EPA

United States Environmental Protection Agency
Washington, DC 20460

PLUGGING AND ABANDONMENT PLAN

Name and Address of Facility	Name and Address of Owner/Operator
Puna Geothermal Venture 14-3860 Kapoho Pahoa Road, Pahoa, HI 96778	Puna Geothermal Venture PO Box 30, Pahoa, HI 96778

Locate Well and Outline Unit on Section Plat - 640 Acres

N / W / E / S

State: HI

County: Hawaii

Permit Number:

Surface Location Description

n/a 1/4 of n/a 1/4 of n/a 1/4 of n/a 1/4 of Section n/a Township n/a Range n/a

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location ___ ft. frm (N/S) ___ Line of quarter section and ___ ft. from (E/W) ___ Line of quarter section.

9029.2 E and 9854.6 N of Kaliu Benchmark

TYPE OF AUTHORIZATION

- [ ] Individual Permit
- [x] Area Permit
- [ ] Rule

Number of Wells: 1

Lease Name: Kapoho State

WELL ACTIVITY

- [ ] CLASS I
- [ ] CLASS II
  - [x] Brine Disposal
  - [ ] Enhanced Recovery
  - [ ] Hydrocarbon Storage
- [ ] CLASS V

Well Number: 13

CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT (LB/FT)	TO BE PUT IN WELL (FT)	TO BE LEFT IN WELL (FT)	HOLE SIZE
22	106.5		0-954	26"
16	97		0-2076	20"
11 3/4	65		0-4885	14 3/4"
8 5/8	44		4647-6970	10 5/8"

METHOD OF EMPLACEMENT OF CEMENT PLUGS

- [x] The Balance Method
- [ ] The Dump Bailer Method
- [ ] The Two-Plug Method
- [ ] Other

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7
Size of Hole or Pipe in which Plug Will Be Placed (inche	10.682	10.682	10.682	10.682	10.682	10.682	10.682
Depth to Bottom of Tubing or Drill Pipe (ft	4300	4100	3900	2900	1900	900	Redimix
Sacks of Cement To Be Used (each plug)	76	76	382	382	382	248	96
Slurry Volume To Be Pumped (cu. ft.)	125	125	622	622	622	405	156
Calculated Top of Plug (ft.)	4100	3900	2900	1900	900	250	0
Measured Top of Plug (if tagged ft.)							
Slurry Wt. (Lb./Gal.)							
Type Cement or Other Material (Class III)							Neat

LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS AND INTERVALS WHERE CASING WILL BE VARIED (if any)

From	To	From	To
4454	8000	Perforated liner	
4885	8263	Open hole	
4615	4721	Dropped Hang down	
0	3375	9 5/8 Hang down (removing)	

Estimated Cost to Plug Wells

$424,000.00

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title (Please type or print)	Signature	Date Signed
Jordan Hara, Plant Manager		08/28/2019

EPA Form 7520-14 (Rev. 12-08)

*Depth of first plug may be revised if wellbore is obstructed
**Range of costs is a function of rig usage

Paperwork Reduction Act Notice

The public reporting and record keeping burden for this collection of information is estimated to average 4.5 hours for operators of Class I hazardous wells, 1.5 hours for operators of Class I non-hazardous wells, 3 hours for operators of Class II wells, and 1.5 hours for operators of Class III wells.
Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to the collection of information; search data sources; complete and review the collection of information; and, transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR Part 9 and 48 CFR Chapter 15.
Please send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques to Director, Office of Environmental Information, Collection Strategies Division, U.S. Environmental Protection Agency (2822), Ariel Rios Building, 1200 Pennsylvania Ave., NW., Washington, DC 20460; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, Attention: Desk Officer for EPA. Please include the EPA ICR number and OMB control number in any correspondence.

OMB No. 2040-0042 Approval Expires 12/31/2011

EPA

United States Environmental Protection Agency
Washington, DC 20460

PLUGGING AND ABANDONMENT PLAN

Name and Address of Facility	Name and Address of Owner/Operator
Puna Geothermal Venture 14-3860 Kapoho Pahoa Road, Pahoa, HI 96778	Puna Geothermal Venture PO Box 30, Pahoa, HI 96778

Locate Well and Outline Unit on Section Plat - 640 Acres

N W E S

State	County	Permit Number
HI	Hawaii	

Surface Location Description

n/a 1/4 of n/a 1/4 of n/a 1/4 of n/a 1/4 of Section n/a Township n/a Range n/a

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface 9638N and 1106E of Kaliu Benchmark

Location ___ ft. frm (N/S) ___ Line of quarter section

and ___ ft. from (E/W) ___ Line of quarter section.

TYPE OF AUTHORIZATION

- [ ] Individual Permit
- [x] Area Permit
- [ ] Rule

Number of Wells 1

Lease Name Kapoho State

WELL ACTIVITY

- [ ] CLASS I
- [ ] CLASS II
  - [x] Brine Disposal
  - [ ] Enhanced Recovery
  - [ ] Hydrocarbon Storage
- [ ] CLASS III

Well Number 15RD

CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT (LB/FT)	TO BE PUT IN WELL (FT)	TO BE LEFT IN WELL (FT)	HOLE SIZE
22	114.8		0-1042	26"
16	84		0-2292	20"
11 3/4	65		0-2992 (milled window)	14 3/4"
8 5/8	36		2789-3901	10 5/8"

METHOD OF EMPLACEMENT OF CEMENT PLUGS

- [x] The Balance Method
- [ ] The Dump Bailer Method
- [ ] The Two-Plug Method
- [ ] Other

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7
Size of Hole or Pipe in which Plug Will Be Placed (inche	5.675	5.675	5.67/7.8	7.8/10.6	10.682	10.682	10.682
Depth to Bottom of Tubing or Drill Pipe (ft	4400	4200	4000	3000	2000	1000	Redimix
Sacks of Cement To Be Used (each plug)	22	22	195	345	382	286	96
Slurry Volume To Be Pumped (cu. ft.	35	35	318	562	622	467	156
Calculated Top of Plug (ft.)	4200	4000	3000	2000	1000	250	0
Measured Top of Plug (if tagged ft.							
Slurry Wt. (Lb./Gal.)							
Type Cement or Other Material (Class III)							Neat

LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS AND INTERVALS WHERE CASING WILL BE VARIED (if any)

From	To	From	To
3756	4460	Blank 6 5/8 liner	
4460	5155	Perforated 6 5/8 liner	
0	2908	Hang down liner (removing)	

Estimated Cost to Plug Wells

$408,825.00

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title *(Please type or print)*	Signature	Date Signed
Jordan Hara, Plant Manager		08/28/2019

EPA Form 7520-14 (Rev. 12-08)

*Depth of first plug may be revised if wellbore is obstructed

**Range of costs is a function of rig usage

Paperwork Reduction Act Notice

The public reporting and record keeping burden for this collection of information is estimated to average 4.5 hours for operators of Class I hazardous wells, 1.5 hours for operators of Class I non-hazardous wells, 3 hours for operators of Class II wells, and 1.5 hours for operators of Class III wells.
Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to the collection of information; search data sources; complete and review the collection of information; and, transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR Part 9 and 48 CFR Chapter 15.
Please send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques to Director, Office of Environmental Information, Collection Strategies Division, U.S. Environmental Protection Agency (2822), Ariel Rios Building, 1200 Pennsylvania Ave., NW., Washington, DC 20460; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, Attention: Desk Officer for EPA. Please include the EPA ICR number and OMB control number in any correspondence.

ATTACHMENT Q-1 – PLUGGING AND ABANDONMENT PLAN (EPA FORM 7520-19)

OMB No. 2040-0042 Approval Expires 4/30/2022

United States Environmental Protection Agency

EPA

WELL REWORK RECORD, PLUGGING AND ABANDONMENT PLAN, OR PLUGGING AND ABANDONMENT AFFIDAVIT

Name and Address, Phone Number and/or Email of Permittee

Puna Geothermal Venture
14-3860 Kapoho Pahoa Road, Pahoa, HI 96778
Jordan Hara jhara@ormat.com 808-896-8551

Permit or EPA ID Number	API Number	Full Well Name
HI596002		Kapoho State (KS) 1A

State	County
Hawaii	Hawaii

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location

____ 1/4 of ____ 1/4 of Section ____ Township ____ Range ____

____ ft. from (N/S) ____ Line of quarter section
____ ft. from (E/W) ____ Line of quarter section.

Latitude N 19° 28' 37.3"

Longitude W 154° 53' 23.9"

Well Class	Timing of Action (pick one)	Type of Action (pick one)
☐ Class I	☑ Notice Prior to Work Date Expected to Commence: TBD	☐ Well Rework
☐ Class II		☑ Plugging and Abandonment
☐ Class III	☐ Report After Work Date Work Ended:	☐ Conversion to a Non-Injection Well
☑ Class V		

Provide a narrative description of the work planned to be performed, or that was performed. Use additional pages as necessary. See instructions.

Plug and Abandonment Plan.

1. Move in suitable rig and associated equipment.
2. Install BOPE suitable for maximum expected pressures.
3. Remove any tubing or hang-down liner.
4. Fill high permeability injection zone with rocks, gravel and sand.
5. Place 200 linear feet of 15 ppg geothermal cement on top of sand. Wait on cement, tag cement, and place more cement if necessary for 200 foot cement plug.
6. Fill hole with 9 ppg bentonite mud from top of cement to next casing shoe.
7. Place 200 linear feet of 15 ppg geothermal cement across each casing shoe with 9 ppg bentonite mud between cement plugs.
8. Place 15 ppg geothermal cement from 170 feet to surface.
9. Remove BOPE.
10. Cut off casing below casing head.
11. Weld plate on casing with well name and date.
12. Rig down.

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR § 144.32)

Name and Official Title *(Please type or print)*	Signature	Date Signed
Jordan Hara, Plant Manager	Jordan L Hara	1-16-2020

OMB No. 2040-0042 Approval Expires 4/30/2022

United States Environmental Protection Agency

EPA

WELL REWORK RECORD, PLUGGING AND ABANDONMENT PLAN, OR PLUGGING AND ABANDONMENT AFFIDAVIT

Name and Address, Phone Number and/or Email of Permittee

Puna Geothermal Venture
14-3860 Kapoho Pahoa Road, Pahoa, HI 96778
Jordan Hara jhara@ormat.com 808-896-8551

Permit or EPA ID Number	API Number	Full Well Name
HI596002		Kapoho State (KS) 3

State	County
Hawaii	Hawaii

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location
____ 1/4 of ____ 1/4 of Section ____ Township ____ Range ____

____ ft. from (N/S) ____ Line of quarter section
____ ft. from (E/W) ____ Line of quarter section.

Latitude N 19° 28' 31.4"

Longitude W 154° 53' 29.3"

Well Class	Timing of Action (pick one)	Type of Action (pick one)
☐ Class I ☐ Class II ☐ Class III ☑ Class V	☑ Notice Prior to Work Date Expected to Commence: TBD ☐ Report After Work Date Work Ended:	☐ Well Rework ☑ Plugging and Abandonment ☐ Conversion to a Non-Injection Well

Provide a narrative description of the work planned to be performed, or that was performed. Use additional pages as necessary. See instructions.

Plug and Abandonment Plan.

1. Move in suitable rig and associated equipment.
2. Install BOPE suitable for maximum expected pressures.
3. Remove any tubing or hang-down liner.
4. Fill high permeability injection zone with rocks, gravel and sand.
5. Place 200 linear feet of 15 ppg geothermal cement on top of sand. Wait on cement, tag cement, and place more cement if necessary for 200 foot cement plug.
6. Fill hole with 9 ppg bentonite mud from top of cement to next casing shoe.
7. Place 200 linear feet of 15 ppg geothermal cement across each casing shoe with 9 ppg bentonite mud between cement plugs.
8. Place 15 ppg geothermal cement from 170 feet to surface.
9. Remove BOPE.
10. Cut off casing below casing head.
11. Weld plate on casing with well name and date.
12. Rig down.

Certification

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Name and Official Title *(Please type or print)*	Signature	Date Signed
Jordan Hara, Plant Manager	Jordan L Hara	1-16-2020

OMB No. 2040-0042 Approval Expires 4/30/2022

United States Environmental Protection Agency

EPA

WELL REWORK RECORD, PLUGGING AND ABANDONMENT PLAN, OR PLUGGING AND ABANDONMENT AFFIDAVIT

Name and Address, Phone Number and/or Email of Permittee

Puna Geothermal Venture
14-3860 Kapoho Pahoa Road, Pahoa, HI 96778
Jordan Hara jhara@ormat.com 808-896-8551

Permit or EPA ID Number	API Number	Full Well Name
HI596002		Kapoho State (KS) 11

State	County
Hawaii	Hawaii

Locate well in two directions from nearest lines of quarter section and drilling unit

Latitude N 19° 28' 37.1"

Longitude W 154° 53' 27.4"

Surface Location

___ 1/4 of ___ 1/4 of Section ___ Township ___ Range ___

___ ft. from (N/S) ___ Line of quarter section
___ ft. from (E/W) ___ Line of quarter section.

Well Class	Timing of Action (pick one)	Type of Action (pick one)
☐ Class I ☐ Class II ☐ Class III ☑ Class V	☑ Notice Prior to Work Date Expected to Commence: TBD ☐ Report After Work Date Work Ended:	☐ Well Rework ☑ Plugging and Abandonment ☐ Conversion to a Non-Injection Well

Provide a narrative description of the work planned to be performed, or that was performed. Use additional pages as necessary. See instructions.

Plug and Abandonment Plan.

1. Move in suitable rig and associated equipment.
2. Install BOPE suitable for maximum expected pressures.
3. Remove any tubing or hang-down liner.
4. Fill high permeability injection zone with rocks, gravel and sand.
5. Place 200 linear feet of 15 ppg geothermal cement on top of sand. Wait on cement, tag cement, and place more cement if necessary for 200 foot cement plug.
6. Fill hole with 9 ppg bentonite mud from top of cement to next casing shoe.
7. Place 200 linear feet of 15 ppg geothermal cement across each casing shoe with 9 ppg bentonite mud between cement plugs.
8. Place 15 ppg geothermal cement from 170 feet to surface.
9. Remove BOPE.
10. Cut off casing below casing head.
11. Weld plate on casing with well name and date.
12. Rig down.

Certification

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Name and Official Title *(Please type or print)*	Signature	Date Signed
Jordan Hara, Plant Manager	Jordan L Hara	1-16-2020

OMB No. 2040-0042 Approval Expires 4/30/2022

United States Environmental Protection Agency

EPA

WELL REWORK RECORD, PLUGGING AND ABANDONMENT PLAN, OR PLUGGING AND ABANDONMENT AFFIDAVIT

Name and Address, Phone Number and/or Email of Permittee

Puna Geothermal Venture
14-3860 Kapoho Pahoa Road, Pahoa, HI 96778
Jordan Hara jhara@ormat.com 808-896-8551

Permit or EPA ID Number	API Number	Full Well Name
HI596002		Kapoho State (KS) 13

State	County
Hawaii	Hawaii

Locate well in two directions from nearest lines of quarter section and drilling unit

Latitude N 19° 28' 38.5"

Longitude W 154° 53' 24.7"

Surface Location

____ 1/4 of ____ 1/4 of Section ____ Township ____ Range ____

____ ft. from (N/S) ____ Line of quarter section

____ ft. from (E/W) ____ Line of quarter section.

Well Class	Timing of Action (pick one)	Type of Action (pick one)
☐ Class I	☑ Notice Prior to Work	☐ Well Rework
☐ Class II	Date Expected to Commence: TBD	☑ Plugging and Abandonment
☐ Class III	☐ Report After Work	☐ Conversion to a Non-Injection Well
☑ Class V	Date Work Ended:	

Provide a narrative description of the work planned to be performed, or that was performed. Use additional pages as necessary. See instructions.

Plug and Abandonment Plan.

1. Move in suitable rig and associated equipment.
2. Install BOPE suitable for maximum expected pressures.
3. Remove any tubing or hang-down liner.
4. Fill high permeability injection zone with rocks, gravel and sand.
5. Place 200 linear feet of 15 ppg geothermal cement on top of sand. Wait on cement, tag cement, and place more cement if necessary for 200 foot cement plug.
6. Fill hole with 9 ppg bentonite mud from top of cement to next casing shoe.
7. Place 200 linear feet of 15 ppg geothermal cement across each casing shoe with 9 ppg bentonite mud between cement plugs.
8. Place 15 ppg geothermal cement from 170 feet to surface.
9. Remove BOPE.
10. Cut off casing below casing head.
11. Weld plate on casing with well name and date.
12. Rig down.

Certification

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Name and Official Title *(Please type or print)*	Signature	Date Signed
Jordan Hara, Plant Manager	Jordan J. Hara	1-16-2020

OMB No. 2040-0042 Approval Expires 4/30/2022

United States Environmental Protection Agency

EPA

WELL REWORK RECORD, PLUGGING AND ABANDONMENT PLAN, OR PLUGGING AND ABANDONMENT AFFIDAVIT

Name and Address, Phone Number and/or Email of Permittee

Puna Geothermal Venture
14-3860 Kapoho Pahoa Road, Pahoa, HI 96778
Jordan Hara jhara@ormat.com 808-896-8551

Permit or EPA ID Number	API Number	Full Well Name
HI596002		Kapoho State (KS) 15

State	County
Hawaii	Hawaii

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location

____ 1/4 of ____ 1/4 of Section ____ Township ____ Range ____

____ ft. from (N/S) ____ Line of quarter section

____ ft. from (E/W) ____ Line of quarter section.

Latitude N 19° 28' 44.7"

Longitude W 154° 53' 12.7"

Well Class	Timing of Action (pick one)	Type of Action (pick one)
☐ Class I	☑ Notice Prior to Work	☐ Well Rework
☐ Class II	Date Expected to Commence: TBD	☑ Plugging and Abandonment
☐ Class III	☐ Report After Work	☐ Conversion to a Non-Injection Well
☑ Class V	Date Work Ended:	

Provide a narrative description of the work planned to be performed, or that was performed. Use additional pages as necessary. See instructions.

Plug and Abandonment Plan.

1. Move in suitable rig and associated equipment.
2. Install BOPE suitable for maximum expected pressures.
3. Remove any tubing or hang-down liner.
4. Fill high permeability injection zone with rocks, gravel and sand.
5. Place 200 linear feet of 15 ppg geothermal cement on top of sand. Wait on cement, tag cement, and place more cement if necessary for 200 foot cement plug.
6. Fill hole with 9 ppg bentonite mud from top of cement to next casing shoe.
7. Place 200 linear feet of 15 ppg geothermal cement across each casing shoe with 9 ppg bentonite mud between cement plugs.
8. Place 15 ppg geothermal cement from 170 feet to surface.
9. Remove BOPE.
10. Cut off casing below casing head.
11. Weld plate on casing with well name and date.
12. Rig down.

Certification

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Name and Official Title *(Please type or print)*	Signature	Date Signed
Jordan Hara, Plant Manager	Jordan L Hara	1-16-2020

OMB No. 2040-0042 Approval Expires 4/30/2022

United States Environmental Protection Agency

EPA

WELL REWORK RECORD, PLUGGING AND ABANDONMENT PLAN, OR PLUGGING AND ABANDONMENT AFFIDAVIT

Name and Address, Phone Number and/or Email of Permittee

Puna Geothermal Venture
14-3860 Kapoho Pahoa Road, Pahoa, HI 96778
Jordan Hara jhara@ormat.com 808-896-8551

Permit or EPA ID Number	API Number	Full Well Name
HI596002		Kapoho State (KS) 17

State	County
Hawaii	Hawaii

Locate well in two directions from nearest lines of quarter section and drilling unit

Latitude: N 19° 28' 36.478"

Longitude: W 154° 53' 27.599"

Surface Location

____ 1/4 of ____ 1/4 of Section ____ Township ____ Range ____

____ ft. from (N/S) ____ Line of quarter section

____ ft. from (E/W) ____ Line of quarter section.

Well Class	Timing of Action (pick one)	Type of Action (pick one)
☐ Class I	☑ Notice Prior to Work	☐ Well Rework
☐ Class II	Date Expected to Commence: TBD	☑ Plugging and Abandonment
☐ Class III	☐ Report After Work	☐ Conversion to a Non-Injection Well
☑ Class V	Date Work Ended:	

Provide a narrative description of the work planned to be performed, or that was performed. Use additional pages as necessary. See instructions.

Plug and Abandonment Plan.

1. Move in suitable rig and associated equipment.
2. Install BOPE suitable for maximum expected pressures.
3. Remove any tubing or hang-down liner.
4. Fill high permeability injection zone with rocks, gravel and sand.
5. Place 200 linear feet of 15 ppg geothermal cement on top of sand. Wait on cement, tag cement, and place more cement if necessary for 200 foot cement plug.
6. Fill hole with 9 ppg bentonite mud from top of cement to next casing shoe.
7. Place 200 linear feet of 15 ppg geothermal cement across each casing shoe with 9 ppg bentonite mud between cement plugs.
8. Place 15 ppg geothermal cement from 170 feet to surface.
9. Remove BOPE.
10. Cut off casing below casing head.
11. Weld plate on casing with well name and date.
12. Rig down.

Certification

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Name and Official Title (Please type or print)	Signature	Date Signed
Jordan Hara, Plant Manager	Jordan L Hara	1-16-2020

OMB No. 2040-0042 Approval Expires 4/30/2022

United States Environmental Protection Agency

EPA

WELL REWORK RECORD, PLUGGING AND ABANDONMENT PLAN, OR PLUGGING AND ABANDONMENT AFFIDAVIT

Name and Address, Phone Number and/or Email of Permittee

Puna Geothermal Venture
14-3860 Kapoho Pahoa Road, Pahoa, HI 96778
Jordan Hara jhara@ormat.com 808-896-8551

Permit or EPA ID Number	API Number	Full Well Name
HI596002		Kapoho State (KS) 18

State	County
Hawaii	Hawaii

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location

____ 1/4 of ____ 1/4 of Section ____ Township ____ Range ____

____ ft. from (N/S) ____ Line of quarter section

____ ft. from (E/W) ____ Line of quarter section.

Latitude N 19° 28' 32.087"

Longitude W 154° 53' 27.651"

Well Class	Timing of Action (pick one)	Type of Action (pick one)
☐ Class I ☐ Class II ☐ Class III ☑ Class V	☑ Notice Prior to Work Date Expected to Commence: TBD ☐ Report After Work Date Work Ended:	☐ Well Rework ☑ Plugging and Abandonment ☐ Conversion to a Non-Injection Well

Provide a narrative description of the work planned to be performed, or that was performed. Use additional pages as necessary. See instructions.

Plug and Abandonment Plan.

1. Move in suitable rig and associated equipment.
2. Install BOPE suitable for maximum expected pressures.
3. Remove any tubing or hang-down liner.
4. Fill high permeability injection zone with rocks, gravel and sand.
5. Place 200 linear feet of 15 ppg geothermal cement on top of sand. Wait on cement, tag cement, and place more cement if necessary for 200 foot cement plug.
6. Fill hole with 9 ppg bentonite mud from top of cement to next casing shoe.
7. Place 200 linear feet of 15 ppg geothermal cement across each casing shoe with 9 ppg bentonite mud between cement plugs.
8. Place 15 ppg geothermal cement from 170 feet to surface.
9. Remove BOPE.
10. Cut off casing below casing head.
11. Weld plate on casing with well name and date.
12. Rig down.

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR § 144.32)

Name and Official Title *(Please type or print)*	Signature	Date Signed
Jordan Hara, Plant Manager	Jordan L Hara	1-16-2020

OMB No. 2040-0042 Approval Expires 4/30/2022

United States Environmental Protection Agency

EPA

WELL REWORK RECORD, PLUGGING AND ABANDONMENT PLAN, OR PLUGGING AND ABANDONMENT AFFIDAVIT

Name and Address, Phone Number and/or Email of Permittee

Puna Geothermal Venture
14-3860 Kapoho Pahoa Road, Pahoa, HI 96778
Jordan Hara jhara@ormat.com 808-896-8551

Permit or EPA ID Number	API Number	Full Well Name
HI596002		Kapoho State (KS) 19

State	County
Hawaii	Hawaii

Locate well in two directions from nearest lines of quarter section and drilling unit

Latitude: TBD

Longitude: TBD

Surface Location

____ 1/4 of ____ 1/4 of Section ____ Township ____ Range ____

____ ft. from (N/S) ____ Line of quarter section

____ ft. from (E/W) ____ Line of quarter section.

Well Class	Timing of Action (pick one)	Type of Action (pick one)
☐ Class I	☑ Notice Prior to Work	☐ Well Rework
☐ Class II	Date Expected to Commence: TBD	☑ Plugging and Abandonment
☐ Class III	☐ Report After Work	☐ Conversion to a Non-Injection Well
☑ Class V	Date Work Ended:	

Provide a narrative description of the work planned to be performed, or that was performed. Use additional pages as necessary. See instructions.

Plug and Abandonment Plan.

1. Move in suitable rig and associated equipment.
2. Install BOPE suitable for maximum expected pressures.
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6. Fill hole with 9 ppg bentonite mud from top of cement to next casing shoe.
7. Place 200 linear feet of 15 ppg geothermal cement across each casing shoe with 9 ppg bentonite mud between cement plugs.
8. Place 15 ppg geothermal cement from 170 feet to surface.
9. Remove BOPE.
10. Cut off casing below casing head.
11. Weld plate on casing with well name and date.
12. Rig down.

Certification

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Name and Official Title *(Please type or print)*	Signature	Date Signed
Jordan Hara, Plant Manager	Jordan L Hara	1-16-2020

OMB No. 2040-0042 Approval Expires 4/30/2022

United States Environmental Protection Agency

EPA

WELL REWORK RECORD, PLUGGING AND ABANDONMENT PLAN, OR PLUGGING AND ABANDONMENT AFFIDAVIT

Name and Address, Phone Number and/or Email of Permittee

Puna Geothermal Venture
14-3860 Kapoho Pahoa Road, Pahoa, HI 96778
Jordan Hara jhara@ormat.com 808-896-8551

Permit or EPA ID Number	API Number	Full Well Name
HI596002		Kapoho State (KS) 20

State	County
Hawaii	Hawaii

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location

____ 1/4 of ____ 1/4 of Section ____ Township ____ Range ____

____ ft. from (N/S) ____ Line of quarter section
____ ft. from (E/W) ____ Line of quarter section.

Latitude: TBD
Longitude: TBD

Well Class	Timing of Action (pick one)	Type of Action (pick one)
☐ Class I	☑ Notice Prior to Work	☐ Well Rework
☐ Class II	Date Expected to Commence: TBD	☑ Plugging and Abandonment
☐ Class III	☐ Report After Work	☐ Conversion to a Non-Injection Well
☑ Class V	Date Work Ended:	

Provide a narrative description of the work planned to be performed, or that was performed. Use additional pages as necessary. See instructions.

Plug and Abandonment Plan.

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Jordan Hara, Plant Manager	Jordan L Hara	1-16-2020

EPA Form 7520-19 (Rev. 4-19)

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14-3860 Kapoho Pahoa Road, Pahoa, HI 96778
Jordan Hara jhara@ormat.com 808-896-8551

Permit or EPA ID Number	API Number	Full Well Name
HI596002		Kapoho State (KS) 21

State	County
Hawaii	Hawaii

Locate well in two directions from nearest lines of quarter section and drilling unit

Latitude TBD

Longitude TBD

Surface Location

____ 1/4 of ____ 1/4 of Section ____ Township ____ Range ____

____ ft. from (N/S) ____ Line of quarter section

____ ft. from (E/W) ____ Line of quarter section.

Well Class	Timing of Action (pick one)	Type of Action (pick one)
☐ Class I	☑ Notice Prior to Work	☐ Well Rework
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Jordan Hara, Plant Manager	Jordan L Hara	1-16-2020

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Jordan Hara jhara@ormat.com 808-896-8551

Permit or EPA ID Number	API Number	Full Well Name
HI596002		Kapoho State (KS) 22

State	County
Hawaii	Hawaii

Locate well in two directions from nearest lines of quarter section and drilling unit

Latitude TBD

Longitude TBD

Surface Location

____ 1/4 of ____ 1/4 of Section ____ Township ____ Range ____

____ ft. from (N/S) ____ Line of quarter section

____ ft. from (E/W) ____ Line of quarter section.

Well Class	Timing of Action (pick one)	Type of Action (pick one)
☐ Class I	☑ Notice Prior to Work	☐ Well Rework
☐ Class II	Date Expected to Commence: TBD	☑ Plugging and Abandonment
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Jordan Hara, Plant Manager	Jordan f. Hara	1-16-2020

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Jordan Hara jhara@ormat.com 808-896-8551

Permit or EPA ID Number	API Number	Full Well Name
HI596002		Kapoho State (KS) 23

State	County
Hawaii	Hawaii

Locate well in two directions from nearest lines of quarter section and drilling unit

Latitude TBD

Longitude TBD

Surface Location

___ 1/4 of ___ 1/4 of Section ___ Township ___ Range ___

___ ft. from (N/S) ___ Line of quarter section

___ ft. from (E/W) ___ Line of quarter section.

Well Class	Timing of Action (pick one)	Type of Action (pick one)
☐ Class I ☐ Class II ☐ Class III ☑ Class V	☑ Notice Prior to Work Date Expected to Commence: TBD ☐ Report After Work Date Work Ended:	☐ Well Rework ☑ Plugging and Abandonment ☐ Conversion to a Non-Injection Well

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Permit or EPA ID Number	API Number	Full Well Name
HI596002		Kapoho State (KS) 24

State	County
Hawaii	Hawaii

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location

____ 1/4 of ____ 1/4 of Section ____ Township ____ Range ____

____ ft. from (N/S) ____ Line of quarter section
____ ft. from (E/W) ____ Line of quarter section.

Latitude TBD
Longitude TBD

Well Class	Timing of Action (pick one)	Type of Action (pick one)
☐ Class I	☑ Notice Prior to Work	☐ Well Rework
☐ Class II	Date Expected to Commence: TBD	☑ Plugging and Abandonment
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Permit or EPA ID Number	API Number	Full Well Name
HI596002		Kapoho State (KS) 25

State	County
Hawaii	Hawaii

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location

____ 1/4 of ____ 1/4 of Section ____ Township ____ Range ____

____ ft. from (N/S) ____ Line of quarter section
____ ft. from (E/W) ____ Line of quarter section.

Latitude TBD
Longitude TBD

Well Class	Timing of Action (pick one)	Type of Action (pick one)
☐ Class I ☐ Class II ☐ Class III ☑ Class V	☑ Notice Prior to Work Date Expected to Commence TBD ☐ Report After Work Date Work Ended	☐ Well Rework ☑ Plugging and Abandonment ☐ Conversion to a Non-Injection Well

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Jordan Hara jhara@ormat.com 808-896-8551

Permit or EPA ID Number	API Number	Full Well Name
HI596002		Kapoho State (KS) 26

State	County
Hawaii	Hawaii

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location

___ 1/4 of ___ 1/4 of Section ___ Township ___ Range ___

___ ft. from (N/S) ___ Line of quarter section

___ ft. from (E/W) ___ Line of quarter section.

Latitude TBD

Longitude TBD

Well Class	Timing of Action (pick one)	Type of Action (pick one)
☐ Class I	☑ Notice Prior to Work	☐ Well Rework
☐ Class II	Date Expected to Commence TBD	☑ Plugging and Abandonment
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Permit or EPA ID Number	API Number	Full Well Name
HI596002		Kapoho State (KS) 27

State	County
Hawaii	Hawaii

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location

____ 1/4 of ____ 1/4 of Section ____ Township ____ Range ____

____ ft. from (N/S) ____ Line of quarter section

____ ft. from (E/W) ____ Line of quarter section.

Latitude TBD

Longitude TBD

Well Class	Timing of Action (pick one)	Type of Action (pick one)
☐ Class I	✔ Notice Prior to Work	☐ Well Rework
☐ Class II	Date Expected to Commence: TBD	✔ Plugging and Abandonment
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Name and Official Title *(Please type or print)*	Signature	Date Signed
Jordan Hara, Plant Manager	Jordan L Hara	1-16-2020

ATTACHMENT R – NECESSARY RESOURCES

PGV currently maintains an Irrevocable Standby Letter of Credit in the amount of $4,693,080.00 that covers the plugging and abandonment of all geothermal injection wells operated and maintained by PGV in the State of Hawaii. The amount of the bond is substantially in excess of bond amounts required by federal and state agencies for operators of geothermal injection wells in California, Nevada, and Utah. A summary of these requirements is provided in Table R-1 and Table R-2.

Table R-1 IRREVOCABLE STANDBY LETTER OF CREDIT

Table R-2 STANDBY TRUST AGREEMENT

******************** SCRAP ********************

FOREIGN TRADE DEP. DATE: 20,APRIL,2020

TO: STANDARD CHARTERED BANK
1095 AVENUE OF THE AMERICAS
NEW YORK, NY 10036
U.S.A.

:27: SEQUENCE OF TOTAL DATE: 20,APRIL,2020
1/1
:20: TRANSACTION REFERENCE NUMBER
343-02782/20
:23: FURTHER IDENTIFICATION
ISSUE
:77C: DETAILS OF GUARANTEE

40A: /FORM OF DOCUMENTARY CREDIT:
IRREVOCABLE STANDBY

20: /DOCUMENTARY CREDIT NUMBER: 600-02-001885/0

31C: /DATE OF ISSUE:
DATE: JULY 14, 2004

31D: /DATE AND PLACE OF EXPIRY:
DATE: JULY 29, 2005 PLACE: AEIBUS33

50: /ORDERING CUSTOMER/APPLICANT:
PUNA GEOTHERMAL VENTURE
14-3860, KAPOHO-PAHOA RD. PAHOA HI 96778

59: /BENEFICIARY:
AEIBUS33
AMERICAN EXPRESS BANK LTD.
3 WORLD FINANCIAL CENTER 23RD FLOOR,
200 VESEY STREET,
NEW YORK, NY 10285

32B: /CURENCY CODE, AMOUNT:
USD 800,000.- (US DOLLARS EIGHT HUNDRED THOUSAND)

41A: /AVAILABLE WITH....BY..:
S/AEIBUS33
AMERICAN EXPRESS BANK NY
3 WORLD FINANCIAL CENTER, 23RD FLOOR
200 VESEY STREET
NEW YORK, NY 10285
BY: NEGOTIATION

42C: /DRAFTS AT:
NOT REQUIRED

42A: /DRAWEE:
NOT REQUIRED

46A: DOCUMENTS REQUIRED:
A DEMAND FOR PAYMENT FROM AMERICAN EXPRESS BANK LTD,
NEW YORK BY A TESTED TELEX/AUTHENTICATED SWIFT
MESSAGE SENT TO US AT OUR SWIFT CODE (TO: POALILIT)
TO OUR OFFICE LOCATED AT 40 HAMASGER ST., TEL AVIV,
ISRAEL, ON OR BEFORE JULY 29, 2005 OR ANY
AUTOMATICALLY EXTENDED EXPIRATION DATE
STATING THE FOLLOWING:
''WE HEREBY DEMAND PAYMENT OF USD ....(INSERT NUMERALS
AND WORDS) UNDER BANK HAPOALIM B.M. IRREVOCABLE STANDBY

******************** SCRAP ********************

LETTER OF CREDIT NO.600-02-001885/0 AND HEREBY REPRESENT AND WARRANT THAT WE HAVE RECEIVED A DRAWING UNDER OUR STANDY LETTER OF CREDIT NO............ A STANDBY ISSUED IN FAVOR OF U.S. ENVIRONMENTAL PROTECTION AGENCY

47A: ADDITIONAL CONDITIONS:
PLEASE REGARD THIS STANDBY LETTER OF CREDIT ISSUED IN YOUR FAVOR AS AN INDUCEMENT TO ISSUE YOUR STANDBY LETTER OF CREDIT/GUARANTEE IN THE FOLLOWING FORMAT:

QUOTE

BENEFICIARY:
U.S. ENVIRONMENTAL PROTECTION AGENCY
REGION 9, GROUNDWATER OFFICE WTR-9
75 HAWTHRONE STREET
SAN FRANCISCO, CA 94105

ATTN: REGIONAL ADMINISTRATOR

RE: IRREVOCABLE STANDBY LETTER OF CREDIT

DEAR SIR OR MADAM,

WE HEREBY ESTABLISH OUR IRREVOCABLE STANDBY LETTER OF CREDIT NO......... IN YOUR FAVOR, AT THE REQUEST AND FOR THE ACCOUNT OF PUNA GEOTHERMAL VENTURE
14-3860, KAPOHO-PAHOA RD. PAHOA HI 96778
UP TO THE AGGREGATE AMOUNT OF EIGHT HUNDRED THOUSAND U.S. DOLLARS, USD 800,000.- AVAILABLE UPON PRESENTATION OF

1.
YOUR SIGHT DRAFT, BEARING REFERENCE TO THIS LETTER OF CREDIT NO......
AND

2.
YOUR SIGNED STATEMENT READING AS FOLLOWS: ''I CERTIFY THAT THE AMOUNT OF THE DRAFT IS PAYABLE PURSUANT TO REGULATIONS ISSUED UNDER AUTHORITY OF THE SAFE DRINKING WATER ACT.''

THIS LETTER OF CREDIT IS EFFECTIVE AS OF .....(INSERT HERE DATE OF ISSUE)..... AND SHALL EXPIRE ON JULY 14, 2005 BUT SUCH EXPIRATION DATE SHALL BE AUTOMATICALLY EXTENDED FOR A PERIOD OF 1 YEAR ON (DATE) AND ON EACH SUCCESSIVE EXPIRATION DATE, UNLESS, AT LEAST 120 DAYS BEFORE THE CURRENT EXPIRATION DATE, WE NOTIFY BOTH YOU AND PUNA GEOTHERMAL VENTURE BY CERTIFIED MAIL THAT WE HAVE DECIDED NOT TO EXTEND THIS LETTER OF CREDIT BEYOND THE CURRENT EXPIRATION DATE. IN THE EVENT YOU ARE SO NOTIFIED, ANY UNUSED PORTION OF THE CREDIT SHALL BE AVAILABLE UPON PRESENTATION OF YOUR SIGHT DRAFT FOR 120 DAYS AFTER THE DATE OF RECIPT BY BOTH YOU AND PUNA GEOTHERMAL VENTURE, AS SHOWN ON THE SIGNED RETURN RECEIPT.

WHENEVER THIS LETTER OF CREDIT IS DRAWN ON UNDER AND IN COMPLIANCE WITH THE TERMS OF THIS CREDIT, WE SHALL DULY HONOR SUCH DRAFT UPON PRESENTATION TO US, AND WE SHALL DEPOSIT THE AMOUNT OF THE DRAFT DIRECTLY INTO THE STANDBY TRUST FUND OF PUNA GEOTHERMAL VENTURE IN ACCORDANCE WITH YOUR INSTRUCTIONS.

WE CERTIFY THAT THE WORDING OF THIS LETTER OF CREDIT IS IDENTICAL TO THE WORDING SPECIFIED IN 40CFR 144.70(D) AS SUCH REGULATIONS WERE CONSTITUTED ON THE DATE SHOWN IMMEDIATELY BELOW.

THIS CREDIT IS SUBJECT TO (INSERT ''THE MOST RECENT EDITION OF THE UNIFORM CUSTOMS AND PRACTICE FOR DOCUMENTARY CREDITS PUBLISHED AND COPYRIGHTED BY THE INTERNATIONAL CHAMBER OF COMMERCE'', OR ''THE UNIFORM CODE'').

******************** SCRAP ********************

(SIGNATURE(S) AND TITLE(S)OF OFFICIAL(S) OF ISSUING INSTITUTION)

(DATE)

UNQUOTE

PARTIAL DRAWINGS ARE PERMITTED.

IT IS A CONDITION OF THIS STANDBY LC THAT THE EXPIRATION DATE SHALL BE AUTOMATICALLY EXTENDED WITHOUT AMENDMENT, FOR A PERIOD OF ONE YEAR FROM THE EXPIRATION DATE HEREOF OR ANY SUCH AUTOMATICALLY EXTENDED EXPIRATION DATE UNLESS NO LESS THAN 150 DAYS BEFORE ANY SUCH EXPIRATION DATE HEREOF. WE NOTIFY AEB NEW YORK THAT THIS STANDBY LC WILL NOT BE EXTENDED BEYOND THE THEN CURRENT EXPIRATION DATE. ANY SUCH NOTICE OF NON-EXTENSION SHALL BE IN WRITING SENT BY TESTED TELEX/ AUTHENTICATED SWIFT TO SWIFT AEIBUS33 AND SHALL BE DEEMED RECEIVED ON THE DATE OF RECEIPT.

AFTER AEB NEW YORK'S RECEIPT OF SUCH NOTICE OF NON-EXTENSION, AEB, NEW YORK MAY DRAW HEREUNDER, BUT NO LATER THAN THE THEN CURRENT EXPIRATION DATE, BY PRESENTATION OF A DEMAND FOR PAYMENT VIA TESTED TELEX/AUTHENTICATED SWIFT STATING ''WE ARE IN RECEIPT A NOTICE FROM BANK HAPOALIM B.M., TEL AVIV INFORMING OF THEIR ELECTION NOT TO RENEW THIS STANDBY LC NUMBER 600-02-001885/0 FOR AN ADDITIONAL PERIOD OF ONE YEAR AND AS OF THE DATE OF THIS DRAWING WE HAVE NOT RECEIVED FROM THE ISSUING BANK AN ACCEPTABLE REPLACEMENT LETTER OF CREDIT OR ANY OTHER FORM OF ACCEPTABLE SECURITY. AS SUCH WE NOW DRAW AN AMOUNT OF USD .... UNDER THIS STANDBY LC''.

THIS LETTER OF CREDIT IS SUBJECT TO THE UNIFORM CUSTOMS AND PRACTICE FOR DOCUMENTARY CREDITS (1993 REVISION) INTERNATIONAL CHAMBER OF COMMERCE PUBLICATION NO. 500 (''UCP 500'') AND, TO THE EXTENT NOT ADDRESSED BY UCP 500, TO THE LAWS OF THE STATE OF NEW YORK.

71B: /FEE:
APPLICANT

49: /CONFIRMATION INSTRUCTIONS:
CONFIRM

53A: /REIMBURSEMENT BANK:
/ACCOUNT
S/AEIBUS33
AMERICAN EXPRESS BANK, 3 WORLD FINANCIAL CENTER,
23RD FLOOR
200 VESEY STREET,
NEW YORK, NY 10285

78: /INSTRUCTIONS TO PAYING BANK:
AMERICAN EXPRESS BANK LTD., NEW YORK IS AUTHORIZED TO DEBIT OUR ACCOUNT WITH BANK OF NEW YORK, NEW YORK, ON THE DATE OF THEIR TESTED TELEX/AUTHENTICATED SWIFT ADVICE TO US.

72: /SENDER TO RECEIVER INFORMATION:

REGARDS,
BANK HAPOALIM B.M.
FOREIGN TRADE OPERATIONS CENTER
TEL AVIV

בנק הפועלים bank hapoalim

המרכז לסחר בינלאומי תאריך: 10.07.15

לכבוד
אורמת תעשיות בע"מ
ת.ד. 68
יבנה 81100

סניף מרכזי-עסקים 600
(תיבת דואר בסניף מספר: 000019)

הנדון: ערבות מס. 600-02-001885-0

****
* להלן נוסח תיקון הערבות שנשלחה לבקשתכם לחו"ל בהודעה אלקטרונית*
* אנו,בבנק הפועלים,נשמח לעמוד לשרותכם בכל עת. *
* המחלקה לעסקי סחר חוץ-מדור ערבויות:03-7146507 *
****

{2:I767 SCBLUS33 N}
{3:{108: 600-02-001885-0 }}
{4:
TO: STANDARD CHARTERED BANK
1095 AVENUE OF THE AMERICAS
NEW YORK, NY 10036
U.S.A.

SENDER: BANK HAPOALIM B.M.
:27: SEQUENCE OF TOTAL DATE: 10 JULY,2015
1/1
:20: TRANSACTION REFERENCE NUMBER
600-02-001885-0
:21: RELATED REFERENCE NUMBER
777520069275
:23: FURTHER IDENTIFICATION
REQUEST
:31C: DATE OF ISSUE OR REQUEST TO ISSUE
040714
:77C: AMENDMENT DETAILS
VERY URGENT

ATT: GUARANTEE DEPT.

YR REF: 777020010882

RE: OUR STANDBY L/C NO. 600-02-001885/0
FOR THE BALANCED AMOUNT OF USD 1,761,000.-
ISSUED ON JULY 14, 2004
COVERING YOUR STANDBY L/C IN FAVOUR OF
U.S. ENVIRONMENTAL PROTECTION AGENCY

AT THE REQUEST OF OUR CUSTOMER,
WE HEREBY REQUEST YOU TO INCREASE THE AMOUNT OF
YOUR A.M. STANDBY L/C BY THE AMOUNT OF
USD 4,693,080.- (US DOLLARS FOUR MILLION SIX
HUNDRED NINETY THREE THOUSAND AND EIGHTY)

ט.ל.ח.

DEAL NUMBER : 600-02-001885-0

TO A NEW TOTAL AMOUNT OF USD 6,454,080.-
(US DOLLARS SIX MILLION FOUR HUNDRED FIFTY FOUR
THOUSAND EIGHTY).

ACCORDINGLY, WE HEREBY INCREASE THE AMOUNT OF
OUR A.M. STANDBY L/C ISSUED IN YOUR FAVOUR BY
THE AMOUNT OF USD 4,693,080.- (US DOLLARS
FOUR MILLION SIX HUNDRED NINETY THREE THOUSAND
AND EIGHTY) TO A NEW TOTAL INCREASED AMOUNT OF
USD 6,454,080.- (US DOLLARS SIX MILLION FOUR
HUNDRED FIFTY FOUR THOUSAND EIGHTY).

ALL OTHER TERMS AND CONDITIONS OF YOUR STANDBY L/C
AND OF OUR STANDBY L/C IN YOUR FAVOUR,
REMAIN VALID AND UNCHANGED.

BEST REGARDS,
BANK HAPOALIM B.M.
INTERNATIONAL TRADE CENTER

מספרכם 48895

בכבוד רב,
בנק הפועלים בע"מ
המרכז לסחר בינלאומי

ט.ל.ח.
המרכז לסחר בינלאומי ת.ד: 27 תל אביב טלפון: 03-7146300 פקס:
037146367 (טופס מס. AMD018 A1 BV28 MT767)

July 13, 2015

Via Electronic Mail

Sonia Flores
MUFG Union Bank, N.A.
475 Sansome Street, 12^{th} Floor
San Francisco, CA 94111

David Albright
U.S. Environmental Protection Agency, Region 9
Ground Water Office (WTR-9)
75 Hawthorne Street
San Francisco, CA 94105

RE: Amendment to Standby Trust Agreement dated November 3, 2009

Dear All,

Puna Geothermal Venture (PGV) desires to amend the Standby Trust Agreement dated as of November 3, 2009 (the "Agreement"), by and between PGV, the "Grantor", and Union Bank of California (UBOC), the "Trustee".

This letter serves under Section 16 of the Agreement as the written consent of the Grantor, the Trustee, and the EPA Regional Administrator to amend the Agreement.

PGV has recently converted a production well, designated KS-15, into an injection well, and pursuant to EPA requirements the cost to plug and abandon (P&A) must be covered under the existing Fund. PGV has submitted a detailed P&A plan with and updated cost estimate of $2,151,360 to the EPA, which has been accepted.

Pursuant to EPA policy, the current letter of credit will be increased to an amount of $6,454,080, which multiplies the P&A cost by a factor of three (3). Attached please find a revised Schedule A and the updated letter of credit.

PGV has also revised Exhibit A to update the Authorized Persons.

Please signify your consent to the proposed amendment of the Agreement pursuant to Section 16 by signing below.

Thank you for your consideration of this matter.

Connie Stechman

Connie Stechman
Vice President of Finance
Ormat Technologies, Inc.

Approved By:

GRANTOR:

By: Connie Stechman

Connie Stechman

Its: Assistant Secretary

TRUSTEE

By: ______________________

____

Its: ______________________

U.S. ENVIRONMENTAL PROTECTION AGENCY

By: ______________________

____

Its: ______________________

EXHIBIT A

AUTHORIZED PERSONS FOR STANDBY TRUST AGREEMENT

Name	Title
Isaac Angel	**CEO**
Doron Blachar	**CFO**
Connie Stechman	**Assistant Secretary**

SCHEDULE A

Identification of Facilities and Cost Estimates

Schedule A is referenced in the Standby Trust Agreement dated November 3, 2009, by and between Puna Geothermal Venture, the "Grantor" and MUFG Union Bank, N.A. (f/k/a Union Bank, N.A.), the "Trustee".

EPA Identification Number	100000091599
Name of Facility	Puna Geothermal Venture
Address of Facility	P.O. Box 30 14-3860 Kapoho Pahoa Rd.
Current Plugging and Abandonment Cost Estimate	$2,151,360
Date of Estimate	July, 1 2015

ATTACHMENT S

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ATTACHMENT T – EXISTING STATE AND FEDERAL PERMITS

Issuing Agency	Contact	Permit
Department of Health, State of Hawaii	Norris Uehara (808) 586-4273	Under Ground Injection Control (UIC) UH-1529
Environmental Protection Agency	David Albright (415) 972-3971	Under Ground Injection Control (UIC) HI596002
Department of Health, State of Hawaii	Norris Uehara (808) 586-4273	Authority to Construct 7 Geothermal Wells (UIC)
Department of Health, State of Hawaii	Marianne Rossio (808) 586-4273	Non Covered Source Permit No. 0008-02-N
Hawaii County Planning Commission	Michael Yee (808) 961-8125	Geothermal Resource Permit (GRP)
Department of Land and Natural Resources, State of Hawaii	Suzanne Case (808) 587-0400	Plan of Operation
Noise and Radiation Branch, Department of Health, State of Hawaii	James Toma (808) 586-4700	Title 11, Administrative Rules, Department of Health, Chapter 46, Community Noise Control Standards
Department of Labor, State of Hawaii, Boiler Inspection Bureau	Darwin Ching (808) 586-8844	Permit to Operate (PTO) Vent. Air Tk./Melben HPV No. 750-91
Department of Labor, State of Hawaii, Boiler Inspection Bureau	Darwin Ching (808) 586-8844	Permit to Operate (PTO) Air Tank/Hansen HPV 749-91
Department of Labor, State of Hawaii, Boiler Inspection Bureau	Darwin Ching (808) 586-8844	Permit to Operate (PTO) Air Tank/Hansen HPV 748-91
Department of Labor, State of Hawaii, Boiler Inspection Bureau	Darwin Ching (808) 586-8844	Permit to Operate (PTO) Flash Separator/Ormat HPV No. 745-91
Department of Labor, State of Hawaii, Boiler Inspection Bureau	Darwin Ching (808) 586-8844	Permit to Operate (PTO) Flash Separator/Ormat HPV No. 744-91
Department of Labor, State of Hawaii, Boiler Inspection Bureau	Darwin Ching (808) 586-8844	Permit to Operate (PTO) Brine Accumulator HPV No. 743-91
Department of Labor, State of Hawaii, Boiler Inspection Bureau	Darwin Ching (808) 586-8844	Permit to Operate (PTO) Brine Accumulator HPV No. 742-91
Department of Labor, State of Hawaii, Boiler Inspection Bureau	Darwin Ching (808) 586-8844	Permit to Operate (PTO) ESRF Accumulator (Abatement Redundancy) HPV No. 613-96
Department of Labor, State of Hawaii, Boiler Inspection Bureau	Darwin Ching (808) 586-8844	Permit to Operate (PTO) ESRF Accumulator (Abatement Redundancy) HPV No. 613-96
Department of Public Works, County of Hawaii Building Division	James Kurata (808) 961-8321	Certificate of Occupancy: Control House
Department of Public Works, County of Hawaii Building Division	James Kurata (808) 586-8844	Certificate of Occupancy: Control House

ATTACHMENT U – DESCRIPTION OF BUSINESS

Puna Geothermal Venture owns and operates the Puna Geothermal Venture (PGV) Project. The PGV Project is designed to generate electrical energy from geothermal fluids produced from the Kapoho Field. The project delivers its electrical energy to the HELCO energy grid system. The project is planned for an operating life of 35 years.

Type or print all information. See reverse for instructions. OMB No. 2040-0042 Approval Expires 1/31/05

INVENTORY OF INJECTION WELLS

EPA

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
OFFICE OF GROUND WATER AND DRINKING WATER

(This information is collected under the authority of the Safe Drinking Water Act)

1. DATE PREPARED *(Year, Month, Day)*: 19-11-07

2. FACILITY ID NUMBER:

PAPERWORK REDUCTION ACT NOTICE

3. TRANSACTION TYPE *(Please mark one of the following)*

- [ ] Deletion
- [ ] First Time Entry
- [x] Entry Change
- [ ] Replacement

4. FACILITY NAME AND LOCATION

A. NAME *(last, first, and middle initial)*: PUNA GEOTHERMAL VENTURE

B. STREET ADDRESS/ROUTE NUMBER: 14-3860 Kapoho-Pahoa Road / P.O. Box 30

C. LATITUDE

DEG	MIN	SEC
19	28	49N

D. LONGITUDE

DEG	MIN	SEC
154	53	35W

E. TOWNSHIP/RANGE

TOWNSHIP	RANGE	SECT	1/4 SECT

F. CITY/TOWN: Pahoa

G. STATE: HI

H. ZIP CODE: 96778

I. NUMERIC COUNTY CODE:

J. INDIAN LAND *(mark "x")*: [ ] Yes [x] No

5. LEGAL CONTACT:

A. TYPE *(mark "x")*: [x] Owner [x] Operator

B. NAME *(last, first, and middle initial)*: Hara, Jordan

C. PHONE *(area code and number)*: (808) 965-6233

D. ORGANIZATION: Puna Geothermal Venture

E. STREET/P.O. BOX: 14-3860 Kapoho-Pahoa Road / P.O. Box 30

F. CITY/TOWN: Pahoa

G. STATE: HI

H. ZIP CODE: 96778

I. OWNERSHIP *(mark "x")*

- [x] PRIVATE
- [ ] PUBLIC
- [ ] SPECIFY OTHER
- [ ] STATE
- [ ] FEDERAL

6. WELL INFORMATION:

A. CLASS AND TYPE		B. NUMBER OF WELLS		C. TOTAL NUMBER OF WELLS	D. WELL OPERATION STATUS				
		COMM	NON-COMM		UC	AC	TA	PA	AN
3	T	11		11		4	1		
				0					
				0					
				0					
				0					
				0					
				0					

COMMENTS *(Optional)*:

KEY:

DEG = Degree
MIN = Minute
SEC = Second

SECT = Section
1/4 SECT = Quarter Section

COMM = Commercial
NON-COMM = Non-Commercial

AC = Active
UC = Under Construction
TA = Temporarily Abandoned
PA = Permanently Abandoned and Approved by State
AN = Permanently Abandoned and not Approved by State

SECTION 1. DATE PREPARED: Enter date in order of year, month, and day.

SECTION 2. FACILITY ID NUMBER: In the first two spaces, insert the appropriate U.S. Postal Service State Code. In the third space, insert one of the following one letter alphabetic identifiers:

- D - DUNS Number,
- G - GSA Number, or
- S - State Facility Number.

In the remaining spaces, insert the appropriate nine digit DUNS, GSA, or State Facility Number. For example, A Federal facility (GSA - 123456789) located in Virginia would be entered as : VAG123456789.

SECTION 3. TRANSACTION TYPE: Place an "x" in the applicable box. See below for further instructions.

Deletion. Fill in the Facility ID Number.
First Time Entry. Fill in all the appropriate information.
Entry Change. Fill in the Facility ID Number and the information that has changed.
Replacement.

SECTION 4. FACILITY NAME AND LOCATION:

- **A. Name.** Fill in the facility's official or legal name.
- **B. Street Address.** Self Explanatory.
- **C. Latitude.** Enter the facility's latitude (all latitudes assume North Except for American Samoa).
- **D. Longitude.** Enter the facility's longitude (all longitudes assume West except Guam).
- **E. Township/Range.** Fill in the complete township and range. The first 3 spaces are numerical and the fourth is a letter (N,S,E,W) specifying a compass direction. A township is North or South of the baseline, and a range is East or West of the principal meridian (e.g., 132N, 343W).
- **F. City/Town.** Self Explanatory.
- **G. State.** Insert the U.S. Postal Service State abbreviation.
- **H. Zip Code.** Insert the five digit zip code plus any extension.

SECTION 4. FACILITY NAME & LOCATION (CONT'D.):

- **I. Numeric County Code.** Insert the numeric county code from the Federal Information Processing Standards Publication (FIPS Pub 6-1) June 15, 1970, U.S. Department of Commerce, National Bureau of Standards. For Alaska, use the Census Division Code developed by the U.S. Census Bureau.
- **J. Indian Land.** Mark an "x" in the appropriate box (Yes or No) to indicate if the facility is located on Indian land.

SECTION 5. LEGAL CONTACT:

- **A. Type.** Mark an "x" in the appropriate box to indicate the type of legal contact (Owner or Operator). For wells operated by lease, the operator is the legal contact.
- **B. Name.** Self Explanatory.
- **C. Phone.** Self Explanatory.
- **D. Organization.** If the legal contact is an individual, give the name of the business organization to expedite mail distribution.
- **E. Street/P.O. Box.** Self Explanatory.
- **F. City/Town.** Self Explanatory.
- **G. State.** Insert the U.S. Postal Service State abbreviation.
- **H. Zip Code.** Insert the five digit zip code plus any extension.
- **I. Ownership.** Place an "x" in the appropriate box to indicate ownership status.

SECTION 6. WELL INFORMATION:

- **A. Class and Type.** Fill in the Class and Type of injection wells located at the listed facility. Use the most pertinent code (specified below) to accurately describe each type of injection well. For example, 2R for a Class II Enhanced Recovery Well, or 3M for a Class III Solution Mining Well, etc.
- **B. Number of Commercial and Non-Commercial Wells.** Enter the total number of commercial and non-commercial wells for each Class/Type, as applicable.
- **C. Total Number of Wells.** Enter the total number of injection wells for each specified Class/Type.
- **D. Well Operation Status.** Enter the number of wells for each Class/Type under each operation status (see key on other side).

CLASS I Industrial, Municipal, and Radioactive Waste Disposal Wells used to inject waste below the lowermost Underground Source of Drinking Water (USDW).

TYPE
- **1I** Non-Hazardous Industrial Disposal Well.
- **1M** Non-Hazardous Municipal Disposal Well.
- **1H** Hazardous Waste Disposal Well injecting below the lowermost USDW.
- **1R** Radioactive Waste Disposal Well.
- **1X** Other Class I Wells.

CLASS II Oil and Gas Production and Storage Related Injection Wells.

TYPE
- **2A** Annular Disposal Well.
- **2D** Produced Fluid Disposal Well.
- **2H** Hydrocarbon Storage Well.
- **2R** Enhanced Recovery Well.
- **2X** Other Class II Wells.

CLASS III Special Process Injection Wells.

TYPE
- **3G** *In Situ* Gassification Well
- **3M** Solution Mining Well.

CLASS III (CONT'D.)

TYPE
- **3S** Sulfur Mining Well by Frasch Process.
- **3T** Geothermal Well.
- **3U** Uranium Mining Well.
- **3X** Other Class III Wells.

CLASS IV Wells that inject hazardous waste into/above USDWs.

TYPE
- **4H** Hazardous Facility Injection Well.
- **4R** Remediation Well at RCRA or CERCLA site.

CLASS V Any Underground Injection Well not included in Classes I through IV.

TYPE
- **5A** Industrial Well.
- **5B** Beneficial Use Well.
- **5C** Fluid Return Well.
- **5D** Sewage Treatment Effluent Well.
- **5E** Cesspools (non-domestic).
- **5F** Septic Systems.
- **5G** Experimental Technology Well.
- **5H** Drainage Well.
- **5I** Mine Backfill Well.
- **5J** Waste Discharge Well.

PAPERWORK REDUCTION ACT The public reporting and record keeping burden for this collection of information is estimated to average 0.5 hours per response. Burden means the total time, effort, or financial resource expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal Agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to the collection of information; search data sources; complete and review the collection of information; and, transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques to Director, Collection Strategies Division, U.S. Environmental Protection Agency (2822), 1200 Pennsylvania Ave., NW., Washington, D.C. 20460. Include the OMB control number in any correspondence. Do not send the completed forms to this address.

PUNA GEOTHERMAL VENTURE

Well Status

Year	Well Name	Status	Spud Date	Comp Date	Depth	~ Capacity	temp	psig	Comments
1981	KS-1	Production	9/1/1981	11/12/1981	7290	72,000		120	Plugged and Abandoned
	KS-1A	Production	11/15/1981	1/15/1982	6505				Dates Estimated, Plugged
1982	KS-2	Production	1/19/1982	4/2/1982	8005	33,000		173	Plugged
1990	MW-1	Water		12/29/1990	731	260 gpm	112		Inundated by lava on 5/29/2019
1991	MW-2	Monitor		1/23/1991	646	NA	140	0	Inundated by lava on 5/18/2019
	MW-3	Water		8/23/1991	720	1200 gpm	112	60	Inundated by lava on 5/29/2019
	KS-7	Production	1/30/1991	2/28/1991	1678				Plugged and Abandoned
	KS-1A	INJ	3/20/1991	4/23/1991	5745				Workover
1992	KS-8	Production	5/2/1991	8/23/1992	3488				New Well
	KS-3	INJ	8/27/1992	10/3/1992	7406	319gpm	310	354	New Well
	KS-4	INJ	9/13/1992	11/25/1992	6796	450gpm	310	354	New Well
	KS-1A	INJ	10/28/1992	10/29/1992	3743	210gpm	310	356	Run Liner With Crane
1993	KS-9	Production	12/6/1992	1/25/1993	4564				New Well
	KS-10	Production	2/1/1993	4/6/1993	5083				New Well
	KS-8	P&A	4/12/1993	4/30/1993	0				Plugged and Abandoned
	KS-1	P&A	5/7/1993	5/17/1993	0				Plugged and Abandoned
	KS-2	P&A	5/17/1993	5/27/1993	0				Plugged and Abandoned
1999	KS-3	INJ	8/17/1999	8/18/1999	3767	319gpm	310	354	Replace Liner
	KS-4	INJ	8/30/1999	9/6/1999		450gpm	310	354	Coiled Tubing Well Clean Out
	KS-11	Production	9/18/1999	11/22/1999	7951				New Well
2001	KS-1A	INJ	3/1/2001	3/1/2001	3776	210gpm	310	356	Replace Liner
2003	KS-5	Production	8/23/2002	1/12/2003	6418				New Well
	KS-11	INJ	1/23/2003	3/3/2003	6400	3010gpm	310	354	Redrill, Convert to Injection
	KS-10	Production	6/26/2003	7/1/2003	5070				Well Clean out
2004	KS-11	INJ	5/19/2004	5/26/1999	3200				Replace liner
2005	KS-10	Production	5/22/2005	6/11/2005	5210				Redrill
	KS-6	Production	6/26/2005	7/16/2005	6584				New Well
	KS-13	INJ	7/26/2005	12/12/2005	6970	2450gpm	300	165	New Well
2006	KS-6	Production	9/6/2006	9/15/2006	6887				Rework
	KS-5	Production	9/19/2006	10/18/2006	6403				Rework
	KS-4	Production	10/23/2006	11/30/2006	6767				Convert to Production
2009	KS-6	Production	6/13/2009	7/7/2009	6644				Rework
	KS-5	Production	7/12/2009	10/9/2009	6484				Rework
	KS-4	Production	7/15/2009	7/27/2009	6757	183,000	620		Rework
	KS-14	Production	9/12/2009	1/10/2010	5717	1,134,000	600	488	New Well
2010	KS-5	Production	5/2/2010	5/10/2010	6456	95,000	500	480	Rework
	KS-6	Production	5/12/2010	5/18/2010	6605	125,000	500	475	Rework
	KS-4	P&A	5/19/2010		0				Plugged and Abandoned
2012	KS-15	INJ	2/1/2012	7/5/2012					New Well
2015	KS-16	Production	2/16/2015	5/7/2015					New Well
2019	MW-4	Water	1/14/2019	6/172019					New Well
2020	MW-5	Water							TBD

2010 Flow Rates

Well	KS-9	KS-10
WHP	296	390
MW	7	3.2
Brine	152	449
Steam	147	67
Enthalpy	1170	492

ATTACHMENT V - WELL HISTORY

STATUS OF PREVIOUSLY CONSTRUCTED WELLS AND POST LAVA EVENT RECOVERY

The following is a summary of the status of all previously constructed wells at the Puna Geothermal Venture (PGV) project as of October 2019:

1. **KS-1**

   Well KS-1 has been plugged and abandoned in 1993. The program was approved by the DLNR.

2. **KS-2**

   Well KS-2 has been plugged and abandoned in 1993. The program was approved by the DLNR.

3. **KS-1A**

   Injection well KS-1A is completed to a depth of 6,505 feet. This well is currently one of five (5) injection wells in operation at the project. Drilling originally commenced on July 8, 1985 and was completed on September 3, 1985. This well was originally drilled by Diamond Shamrock / Thermal Power Company.

   In May of 1991, PGV completed a workover of the well. A 7" liner was installed and cemented in the well to achieve mechanical integrity, and a 5" hang down liner was then used to inject fluids into the well. The 5" hang down liner has been replaced in 2001 and again with a 4 ½" liner in 2014. KS-1A is currently accepting ~44 thousand pounds of geothermal fluid per hour at ~210ºF and 230 psig under normal operating conditions.

4. **KS-3**

   Injection well KS-3 is completed to a depth of 7,406 feet. This well is currently one of five (5) injection wells at the project. PGV commenced drilling of this well on August 27, 1992 and completed the well on October 3, 1992. KS-3 utilizes a 5" hang down liner, which has been replaced in 1999 and again in 2014. KS-3 is currently accepting ~235 thousand pounds of geothermal fluid per hour at 200ºF and 234 psig under normal operating conditions.

5. **KS-4**

   Injection well KS-4 is completed to a depth of 6,796 feet. This well is now longer in service. PGV commenced drilling of this well on September 13, 1992 and completed the well on November 25, 1992. The well was redrilled to a depth of 6767' and converted to production in 2006. Work commenced on October 23, 2006 and was completed on November 30, 2006. KS-4 was plugged and abandoned in 2010. The program was approved by the DLNR

6. **KS-5**

Production well KS-5 is completed to a depth of 6,350 feet. This well is currently being used to supply geothermal steam to the power plant. PGV commenced drilling of this well on August 23, 2002 and completed the well on January 12, 2003. The well was redrilled in 2009, with work commencing on September 3 and completed on October 10, to a depth of 6484’ and a 4 ½” liner was installed. As of latest testing on March 23, 2015, at ~490 psig well head pressure and ~400º F, KS-5 produces a total mass flow of ~73 thousand pounds per hour at ~40% steam ratio. This flow rate equates to ~1.9 MW.

PRE MAY 2018 LAVA EVENT

Prior to lava inundation, mechanical bridge plug was installed with cement on top in wellbore on 5/24/2018. The well is covered by 15’ of lava, no plans are in place yet to recover or P&A the well.

7. **KS-6**

Production well KS-6 is completed to a depth of 6,584 feet. This well is currently being used to supply geothermal steam to the power plant. PGV commenced drilling of this well on June 26, 2005 and completed the well on August 12, 2005. In 2009, the well was redrilled to a depth of 6644’ and a 7” liner was installed. Redrilling commenced on June 14 and was completed on July 7. As of latest testing on March 23, 2015, at ~300 psig well head pressure and ~405º F, KS-6 produces a total mass flow of ~1.1 million pounds per hour at ~30% steam ratio. This flow rate equates to ~2.4 MW.

PRE MAY 2018 LAVA EVENT

Prior to lava inundation, mechanical bridge plug was installed with cement on top in wellbore on 5/26/2018. The well is covered by 15’ of lava, no plans are in place yet to recover or P&A the well.

8. **KS-7**

Well KS-7 has been plugged and abandoned in 1991. The program was approved by the DLNR.

9. **KS-8**

Well KS-8 has been plugged and abandoned in 1992. The program was approved by the DLNR.

10. **KS-9**

Production well KS-9 is completed to a depth of 4,564 feet. This well is currently being used to supply geothermal steam to the power plant. PGV commenced drilling of this well on December 6, 1992 and completed the well on January 25, 1993. As of latest testing on March 23, 2015, at ~270 psig wellhead pressure and ~400ºF, KS-9 produces a total mass flow of ~455 thousand pounds per hour at ~17% steam ratio. This flow rate equates to ~6.4 MW.

10. **KS-10**

Production well KS-10 is completed to a depth of 5,083 feet. This well is currently being used to supply geothermal steam to the power plant. PGV commenced drilling of this well on February 1, 1993 and completed the well on April 6, 1993. The wellbore of KS-10 was cleaned out in September 2003. The well was then redrilled in 2005, with work commencing on May 22 and completed on June 11, to a depth of 5061'. As of its latest testing in September 2013, at ~390 psig wellhead pressure and ~400ºF, KS-10 produces a total mass flow of ~246 thousand pounds per hour at an estimated ~10% steam ratio. This flow rate equates to ~3.3 MW. KS-10 was out of service and in a static condition during the 2015 testing and remains in a static condition to date.

11. **KS-11**

Injection well KS-11 is completed to a depth of 7,951 feet. This well is currently one of five (5) injection wells in operation at the project. PGV originally commenced drilling of this well on September 18, 1999 and completed the well on November 22, 1999 as a production well. In 2003, PGV converted KS-11 to an injection well. The conversion work commenced on January 22 and was completed on March 3. KS-11 utilized a 9-5/8" hang down liner. The well was redrilled in 2009, with work commencing on November 21 and completed on December 8, to a depth of 6872'. A 7" hang down liner was installed. This liner was replaced in 2013. This well is currently accepting ~48 thousand pounds per hour at ~200º F and 220 psig under normal operating conditions.

PRE MAY 2018 LAVA EVENT

No exact date on when the well inundated by lava, plant personnel were evacuated at the time. Lava was removed from the wellhead, no plans are in place yet to recover or P&A the well.

12. **KS-13**

Injection well KS-13 is completed to a depth of 8297 feet. This well is currently one of five (5) injection wells in operation at the project. PGV originally commenced drilling of this well on August 26, 2005 and completed the well on November 10, 2005 as an injection well. KS-13 utilized an 8-5/8" hang down liner. The liner was replaced in 2013. This well is currently accepting ~600 thousand pounds per hour at ~210º F and 215 psig under normal operating conditions.

13. **KS-14**

Production well KS-14 is completed to a depth of 5717 feet. This well is currently being used to supply geothermal steam to the power plant. PGV originally commenced drilling of this well on February 7, 2010 and completed the well on April 2, 2010 as a production well. As of latest testing on March 23, 2015, at ~500 psig wellhead pressure and ~410ºF, KS-14 produces a total mass flow of ~952 thousand pounds per hour at ~23% steam ratio. This flow rate equates to ~16.3 MW.

14. **KS-15**

Injection well KS-15 is completed to a depth of 5182 feet. This well is currently one of five (5) injection wells in operation at the project. Originally drilled as a production well, it was converted into an injection well in 2015. PGV originally commenced drilling of this well on February 29, 2012 and completed the well on July 8, 2012 as a production well. The well was converted in 2015 with the work commenced on June 30 and was completed on July 3. KS-15 utilized a 7" hang down liner. This well is currently accepting ~ 1.06 million pounds per hour at ~195º F and 180 psig under normal operating conditions.

15. **KS-16**

Production well KS-16 is completed to a depth of 5762 feet. This well is currently being used to supply geothermal steam to the power plant. PGV originally commenced drilling of this well on February 16, 2015 and completed the well on May 5, 2015 as a production well. KS-15 was not yet in service during the latest testing on March 23, 2015.

PGV Water Wells

12. **MW-1**
Monitoring/water supply well MW-1 is completed to a depth of 731 feet. This well supplies water for the power plant operations. MW-1 is sampled in accordance with the Hydrologic Monitoring Program. It provides ~260 gpm.

DURING MAY 2018 LAVA EVENT

Monitoring well was inundated by lava on 5/29, covered under 20' of lava, no plans are in place yet to recover or P&A the well.

13. **MW-2**
Monitoring well MW-2 is completed to a depth of 646 feet. MW-2 is sampled in accordance with the Hydrologic Monitoring Program.

DURING MAY 2018 LAVA EVENT

Monitoring well was inundated by lava on 5/18, covered under 25' of lava, no plans are in place yet to recover or P&A the well.

14. **MW-3**

Monitoring/water supply well MW-3 is completed to a depth of 720 feet. This well supplies water for the power plant and drilling operations. It provides ~1200 gpm.

DURING MAY 2018 LAVA EVENT

Monitoring well was inundated by lava on 5/29, covered under 20' of lava, no plans are in place yet to recover or P&A the well.

POST MAY 2018 LAVA EVENT WELLFIELD STATUS

Production Well KS-14 well maintenance is currently in progress. P/T surveys are ongoing, once the resource has been recovered a final P/T will be performed and a report will be forwarded.

- Once a resource has been established, a minimal bleed (150-200gpm) will flow to KS-15 injection well.

Production Well KS-9 bridge plug was removed and well maintenance was performed. Well casing damage was identified. Well maintenance was suspended and bridge plug was reinstalled, wellhead master valves were isolated, no plans yet on recovery of the well.

Production Well KS-10 5/27 installed a bridge plug, wellhead master valves were isolated. No well maintenance has been performed.

Production Well KS-16 5/28 installed a bridge plug, wellhead master valves were isolated. No well maintenance has been performed.

Injection Well KS-3 wellhead master valves were isolated. No well maintenance has been performed.

Injection Well KS-1A wellhead master valves were isolated. No well maintenance has been performed.

Injection Well KS-13 well maintenance has been performed, MIT completed in March 2019, MIT report submitted to EPA and HDOH UIC in July 2019.

Injection Well KS-15 well maintenance has been performed, MIT completed in March 2019, MIT report submitted to EPA and HDOH UIC in July 2019

Monitoring Well (MW) 4- Commissioned in February 2019.

Monitoring Well (MW) 5- Drilling permit approved by DLNR CWRM, drilling in progress

GTW 3- possible off-site monitoring well.

PROPOSED GEOTHERMAL WELLS

KAPOHO STATE (KS) 18	**WELLPAD LOCATION**	**E**
KAPOHO STATE (KS) 17	**WELLPAD LOCATION**	**A**
KAPOHO STATE (KS) 19	**WELLPAD LOCATION**	**TBD**
KAPOHO STATE (KS) 20	**WELLPAD LOCATION**	**TBD**
KAPOHO STATE (KS) 21	**WELLPAD LOCATION**	**TBD**
KAPOHO STATE (KS) 22	**WELLPAD LOCATION**	**TBD**
KAPOHO STATE (KS) 23	**WELLPAD LOCATION**	**TBD**
KAPOHO STATE (KS) 24	**WELLPAD LOCATION**	**TBD**
KAPOHO STATE (KS) 25	**WELLPAD LOCATION**	**TBD**
KAPOHO STATE (KS) 26	**WELLPAD LOCATION**	**TBD**
KAPOHO STATE (KS) 27	**WELLPAD LOCATION**	**TBD**

Surface equipment locations have not changed for KS-17 and KS-18. KS-18 and KS-17 resource locations have not changed from pre 2018 lava event. If drilling plans are changed, regulatory agencies approval will be needed prior to implementation.

INSTALLATION OF MONITORING WELLS OUTSIDE OF PRODUCTION AND INJECTION ZONES

Monitoring Well (MW) 4 Commissioned in February 2019.
Monitoring Well (MW) 5 Drilling permit approved by DLNR CWRM, no date yet to commence the drilling.
GTW 3- possible off-site monitoring well.

Pre-lava, MW-1 and MW-3 source of water was the same. MW-2 was the only well offsite used for monitoring.

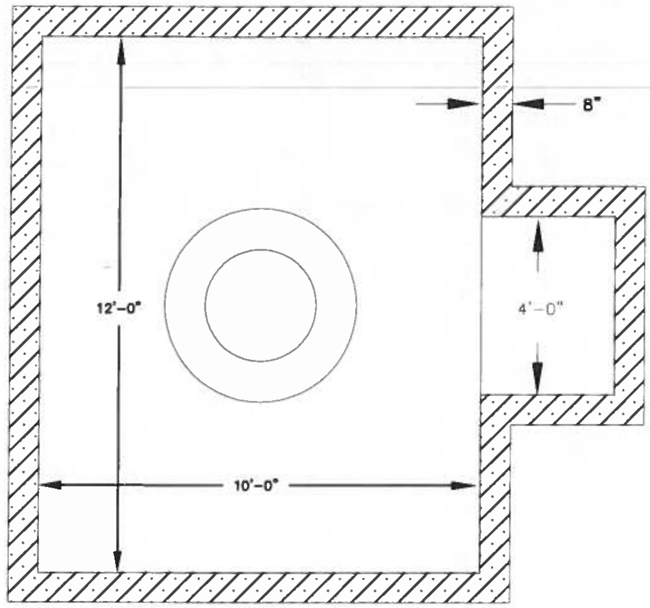
PLANT RECOVERY SCHEDULE

Tentative schedule for production well start up is scheduled in December 2019 with the plant startup, production well minimal bleeds need to be established. These minimal bleeds (150-200 gpm nominal) to an injection well keep the production well hot and prevents gasses from collecting in the wellbore.

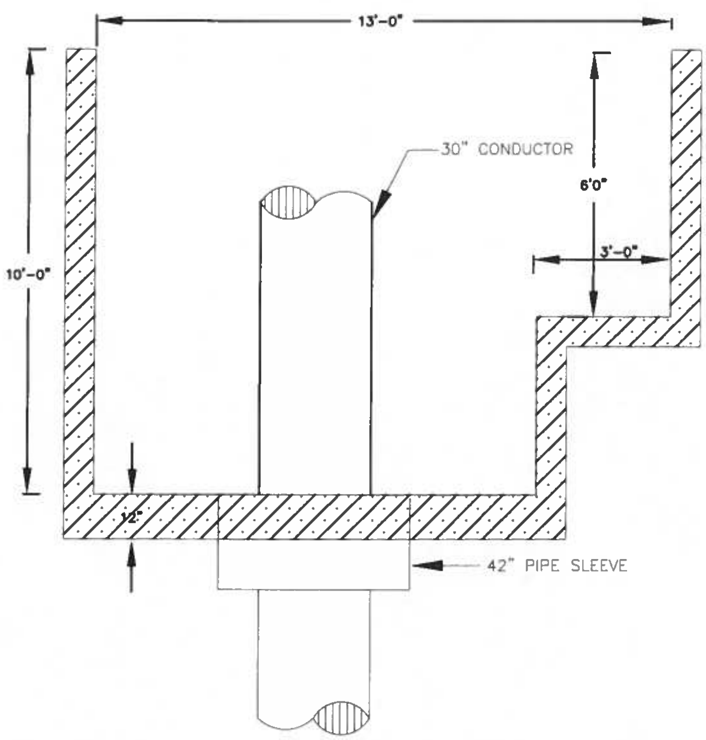
Injection Well KS-13 well maintenance/cleaning has been performed, MIT completed in March 2019, MIT report submitted to EPA and HDOH UIC in July 2019.

Injection Well KS-15 well maintenance/cleaning has been performed, MIT completed in March 2019, MIT report submitted to EPA and HDOH UIC in July 2019.

Injection Well KS-13, planned downhole work is tentatively planned to be performed, once there is a downhole work maintenance plan completed, PGV will forward this to EPA and HDOH to approve the work. MIT will be performed after the work is completed and the report forwarded.

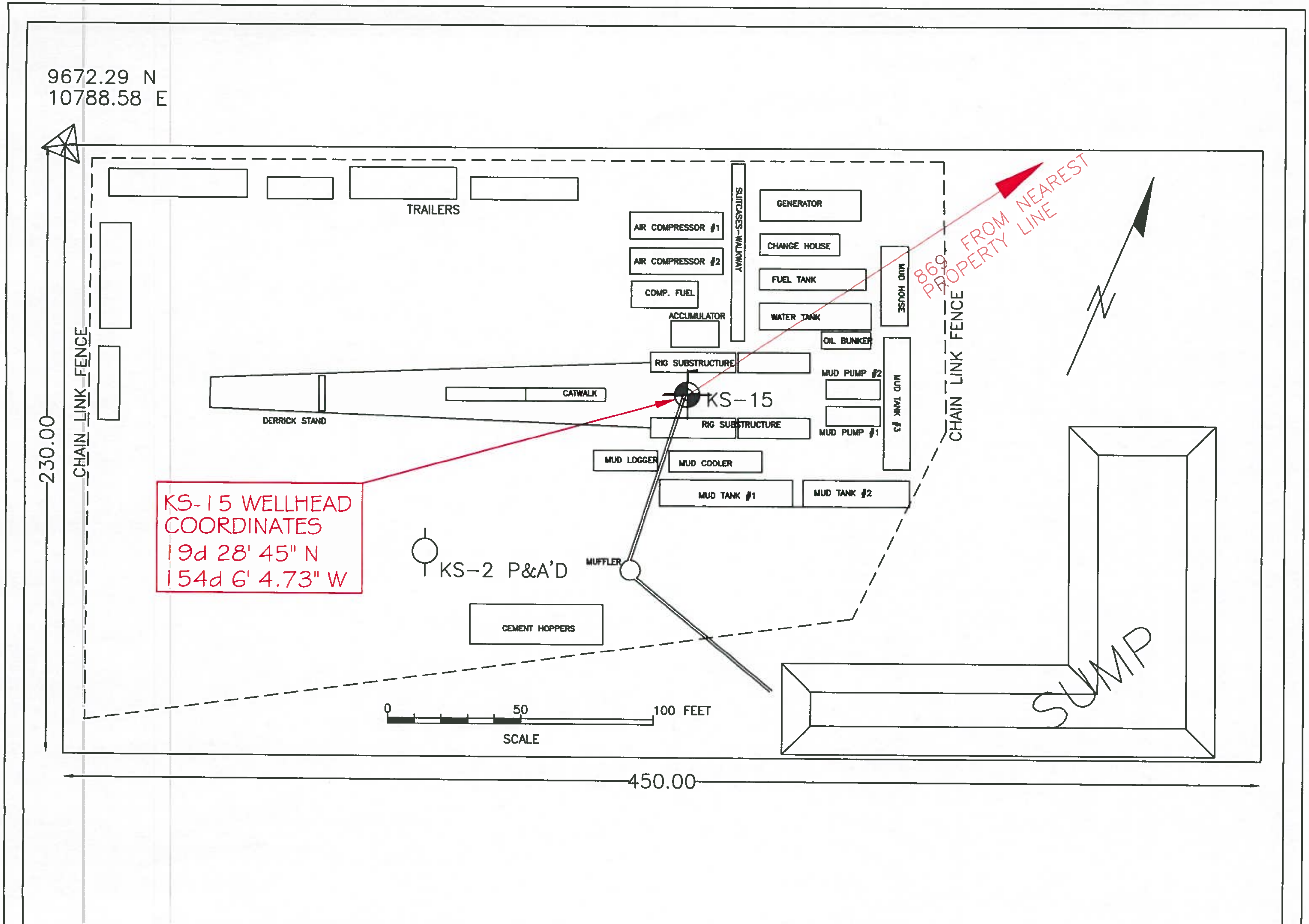


PLAN

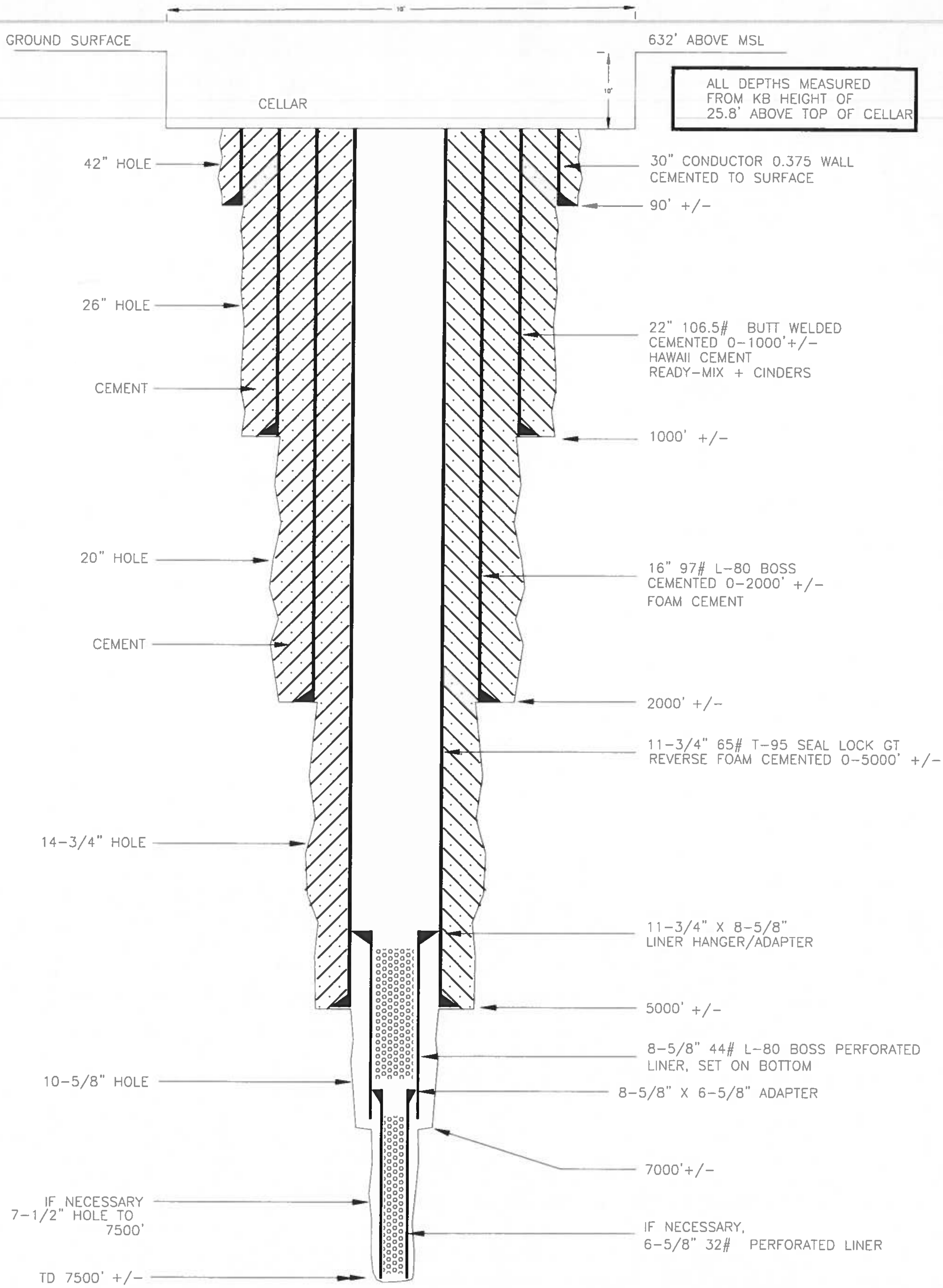


VERTICAL SECTION

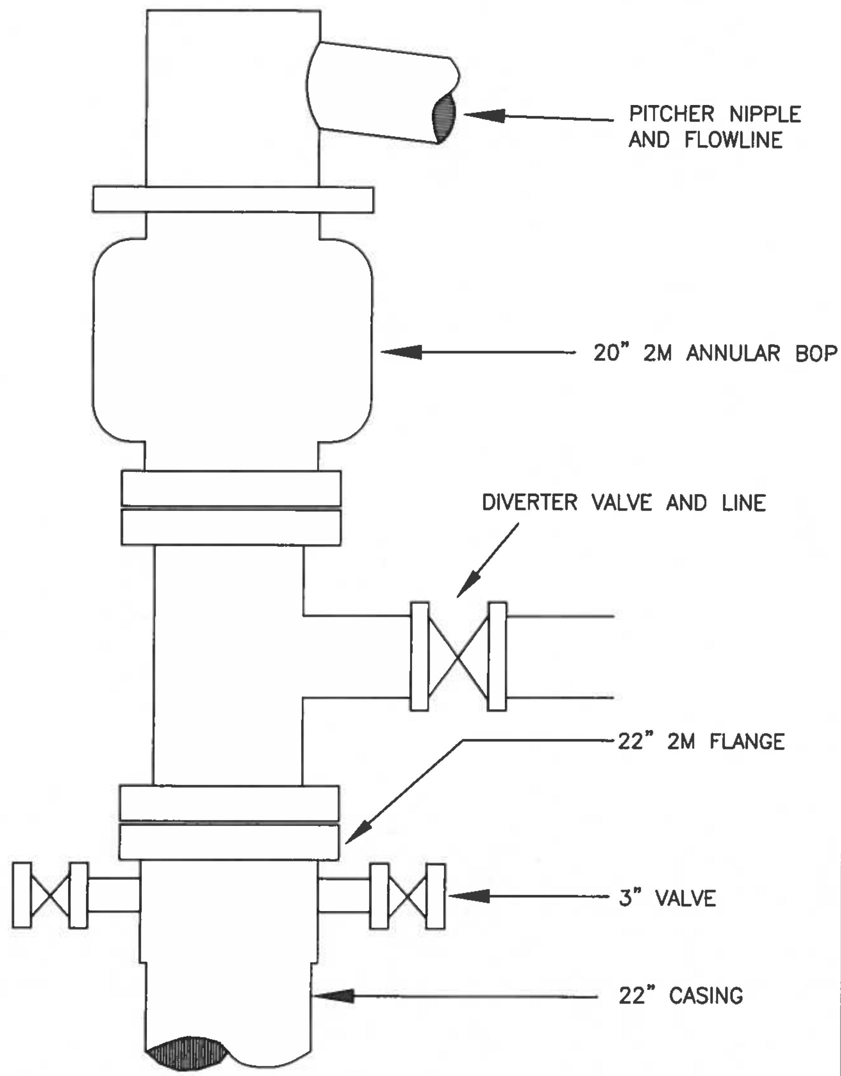
PUNA GEOTHERMAL VENTURE	GEOTHERMAL WELL KS-16 WELL CELLAR	DATE: 11/13/2014		FIGURE 3-1



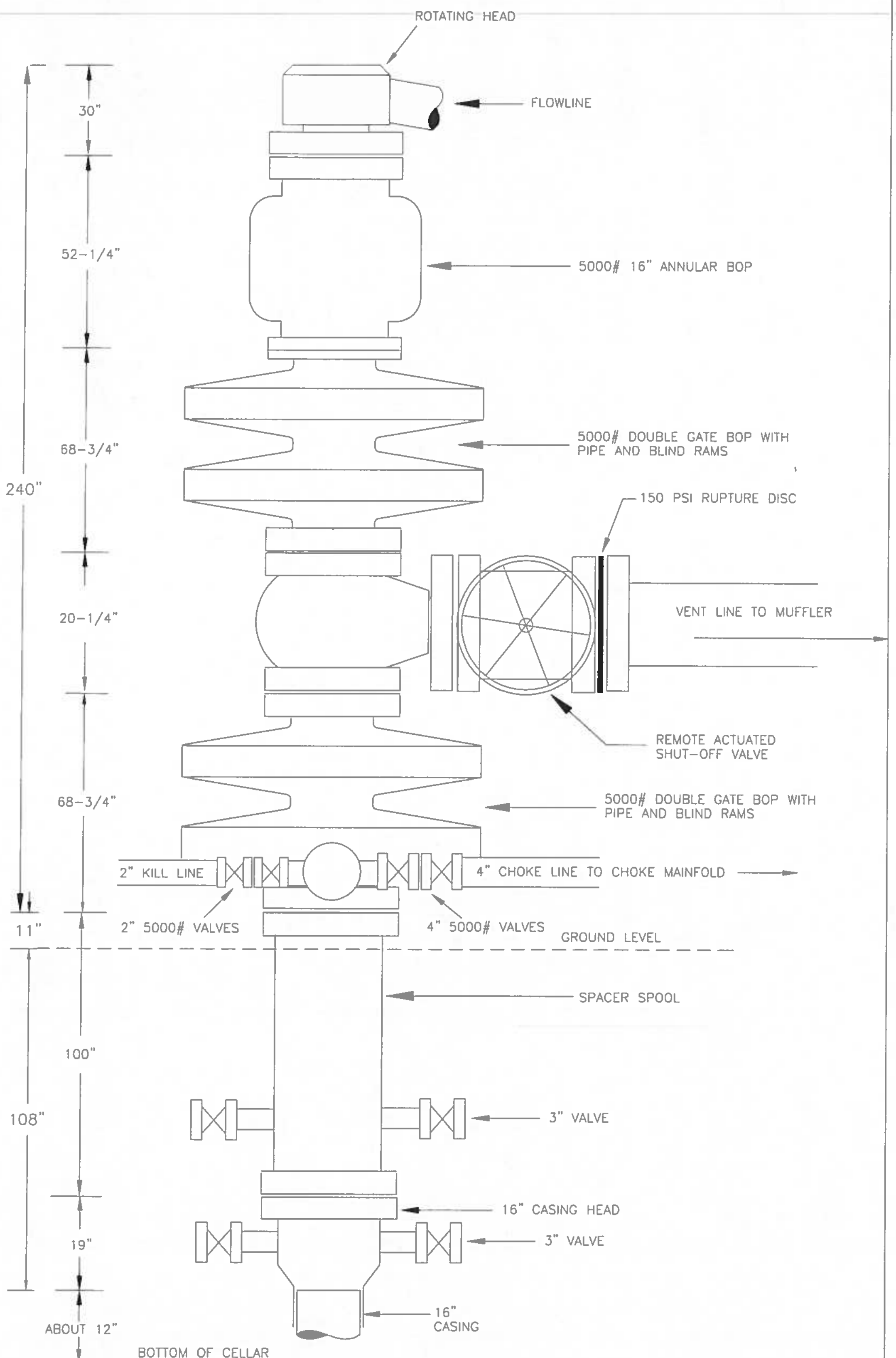
PUNA G THERMAL VENTURE | GEOTHER WELL KS—15 RIG LAYOUT | DATE: 5/10/2011 | BY: WM. TE | FIGUR —2



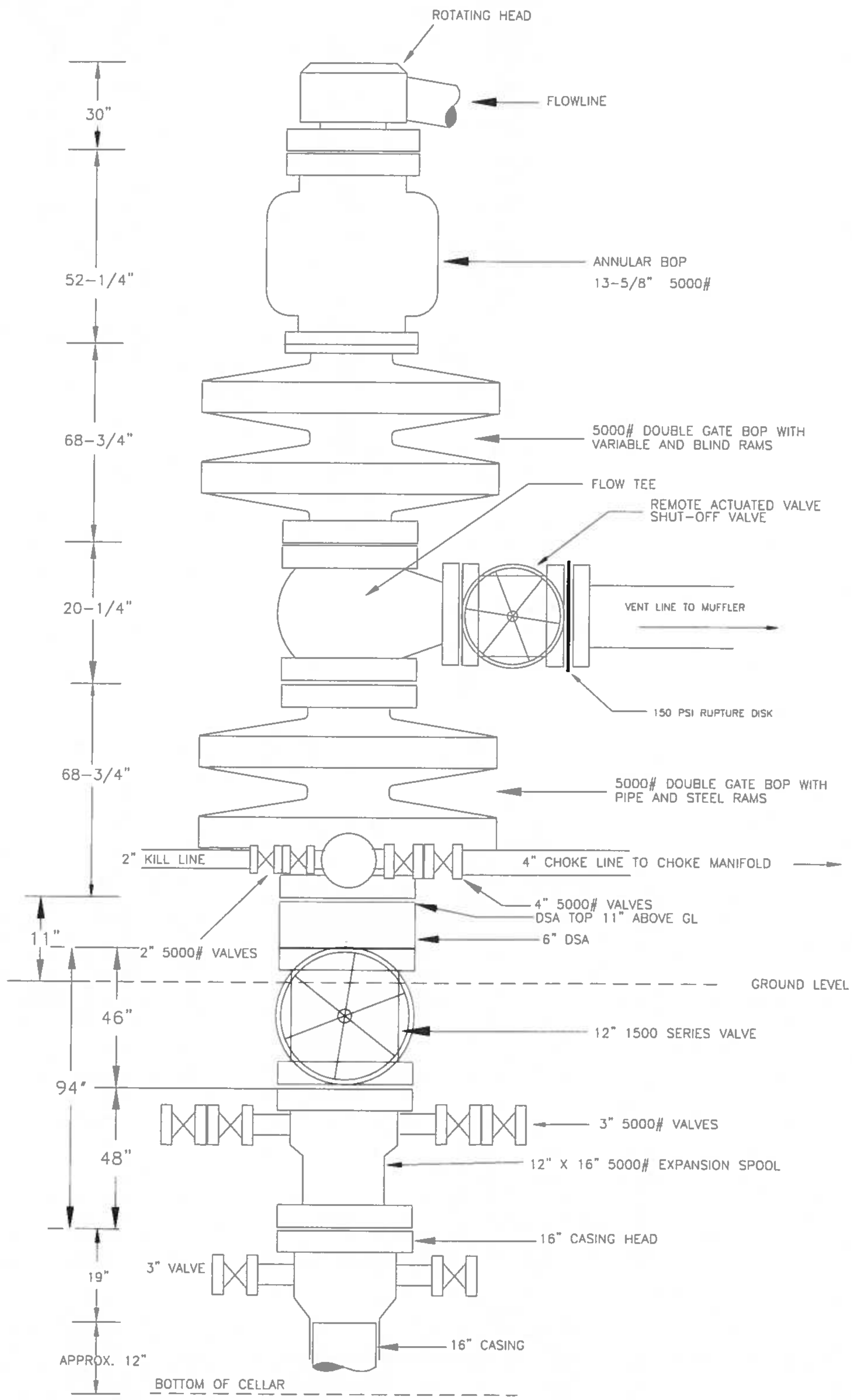
PUNA GEOTHERMAL VENTURE	GEOTHERMAL WELL KS- **16** WELL DESIGN AND CASING SCHEMATIC	REV. 0	NOT TO SCALE	
		DATE: **11/13/2014**		FIGURE 3-3



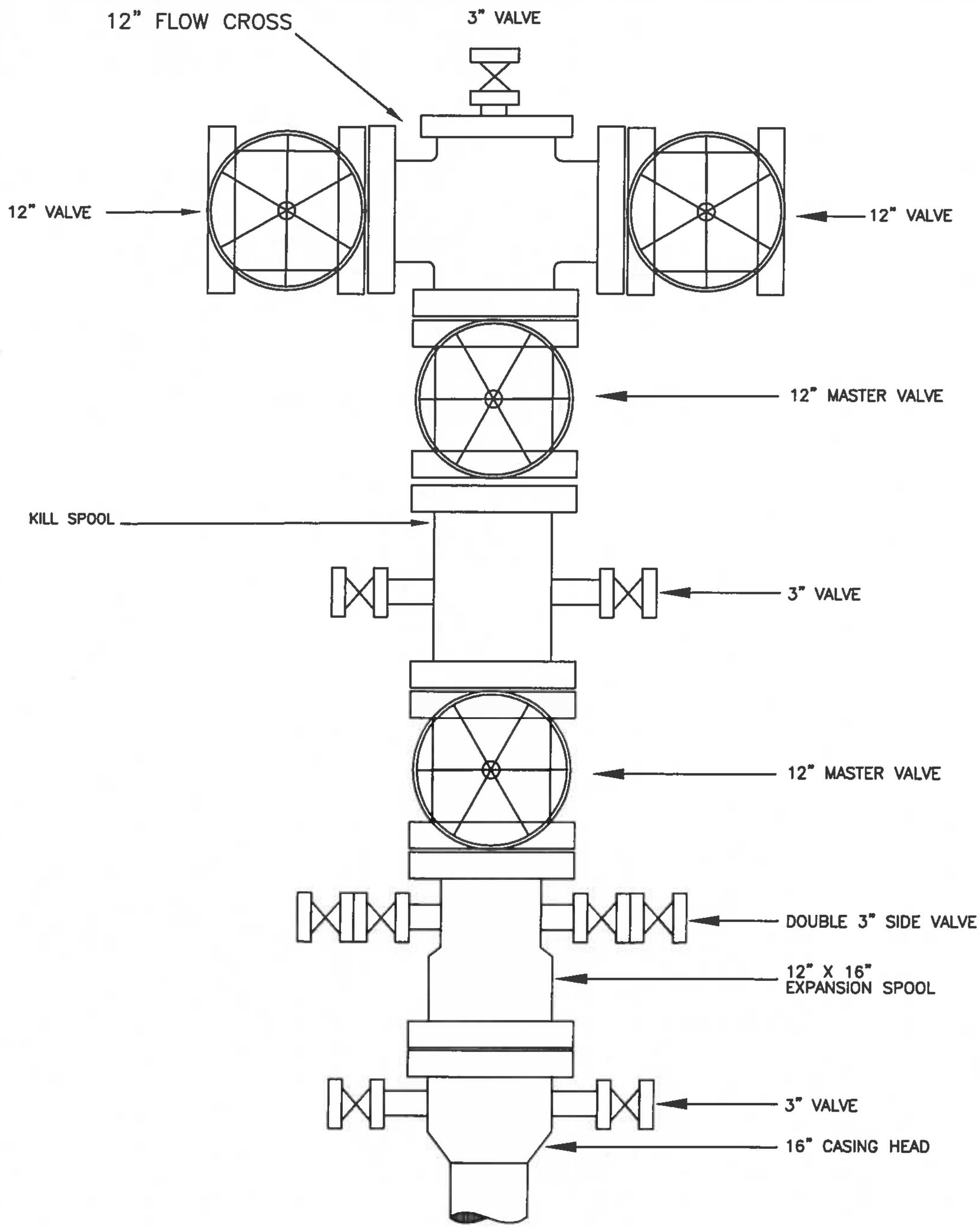
PUNA GEOTHERMAL VENTURE	GEOTHERMAL PRODUCTION WELL KS-16 20" BOP CONFIGURATION	DATE: 11/13/2014	BY:	FIGURE 3-4



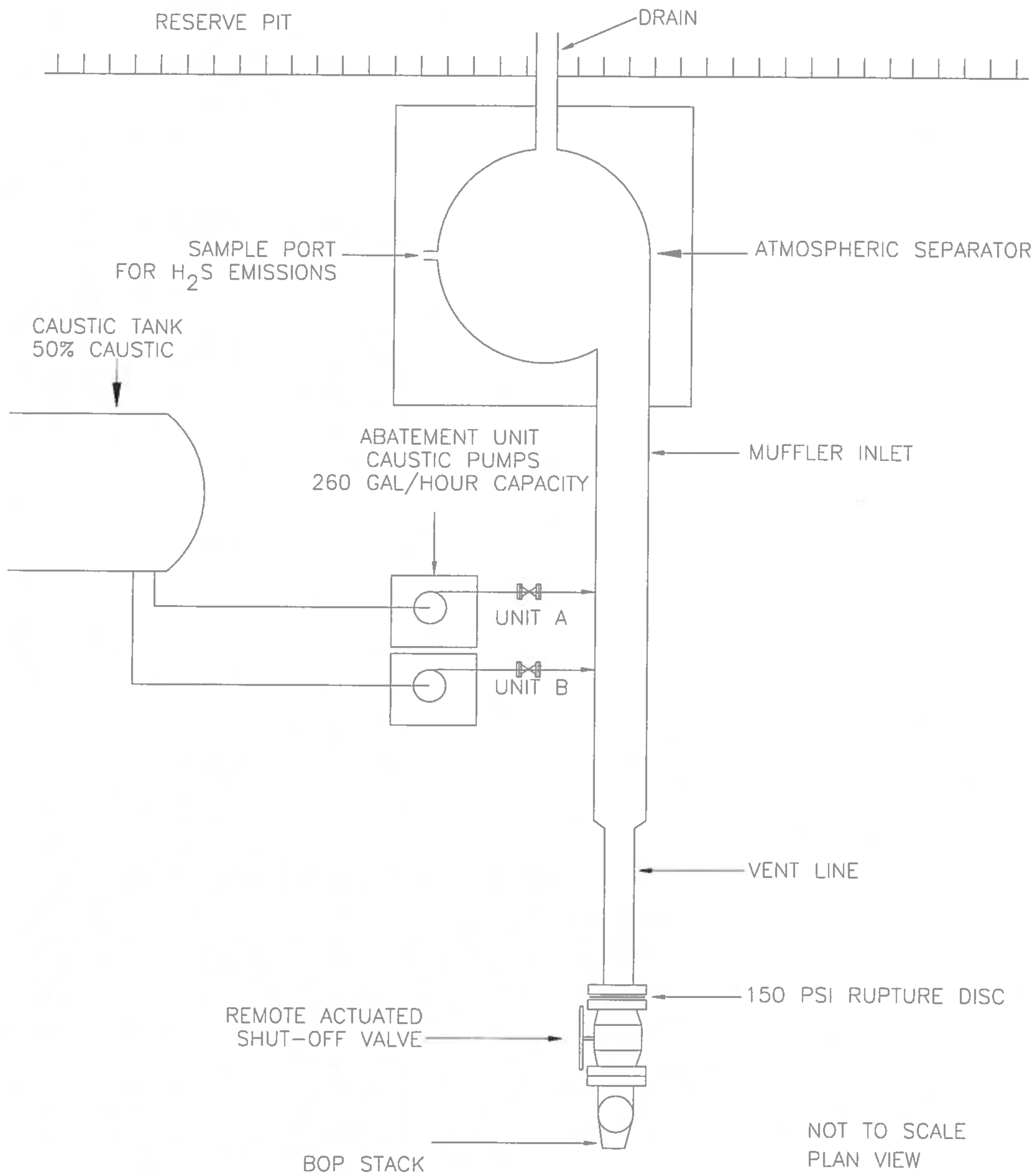
PUNA GEOTHERMAL VENTURE	GEOTHERMAL WELL KS-**16** 16" BOP CONFIGURATION	REV. 0	NOT TO SCALE	
		DATE: 11/13/2014		FIGURE 3-5



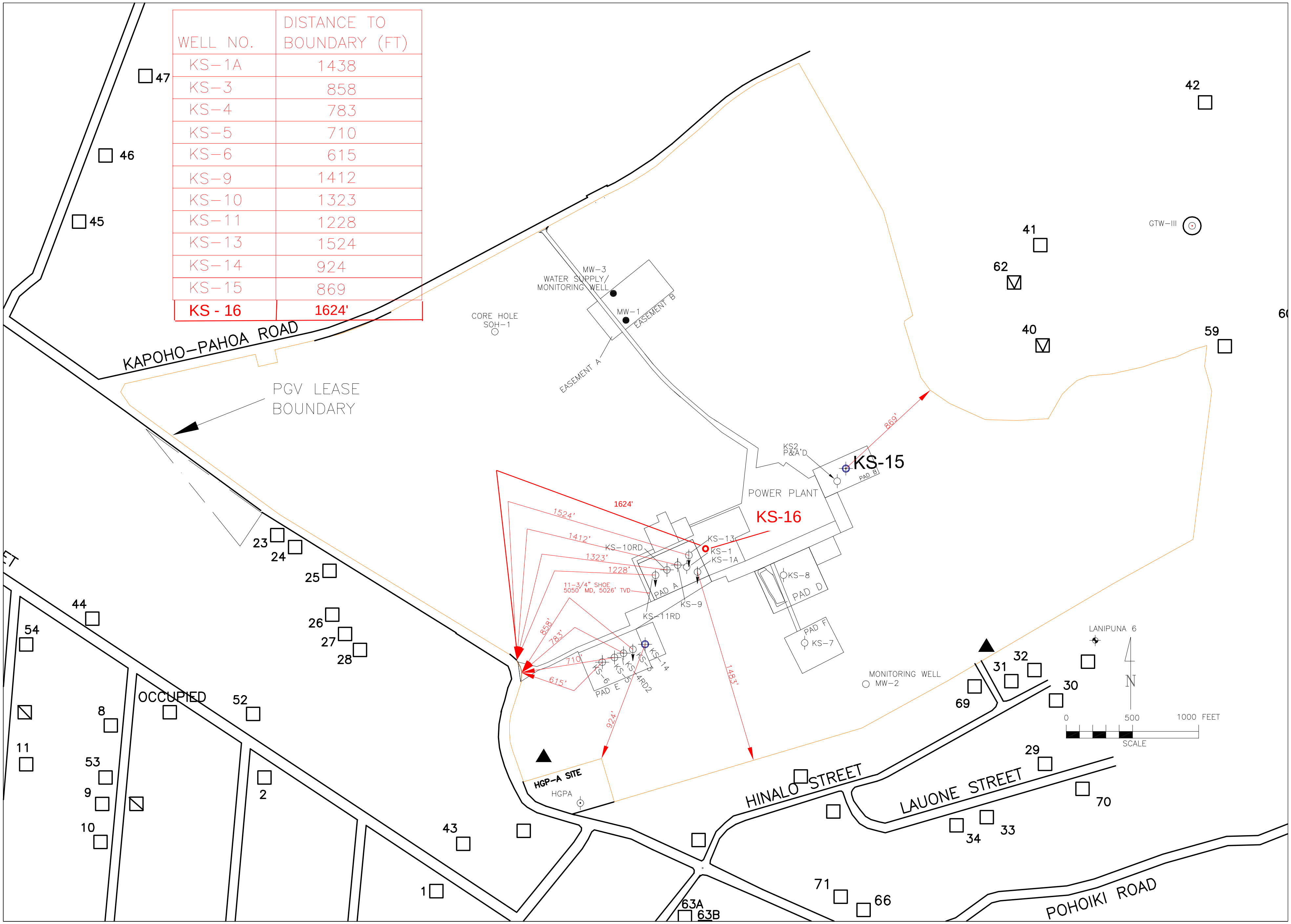
PUNA GEOTHERMAL VENTURE	GEOTHERMAL WELL KS- 16 11-3/4" BOP CONFIGURATION	REV. 0 DATE: 11/13/2014	NOT TO SCALE	FIGURE 3-6



PUNA GEOTHERMAL VENTURE	GEOTHERMAL WELL KS- 16 WELLHEAD CONFIGURATION	DATE: 11/13/2014	BY:	FIGURE 3-7



PUNA GEOTHERMAL VENTURE	GEOTHERMAL WELL KS-16 MUFFLER AND ABATEMENT SYSTEM DURING DRILLING	DATE: 11/13/2014		FIGURE 3-8



WELL NO.	DISTANCE TO BOUNDARY (FT)
KS–1A	1438
KS–3	858
KS–4	783
KS–5	710
KS–6	615
KS–9	1412
KS–10	1323
KS–11	1228
KS–13	1524
KS–14	924
KS–15	869
KS - 16	**1624'**

EXPLANATION

710' DISTANCE (FT) FROM WELLHEAD TO NEAREST PGV LEASE BOUNDARY

GEOTHERMAL WELL, PLUGGED AND ABANDONED

GEOTHERMAL PRODUCTION WELL

GEOTHERMAL INJECTION WELL

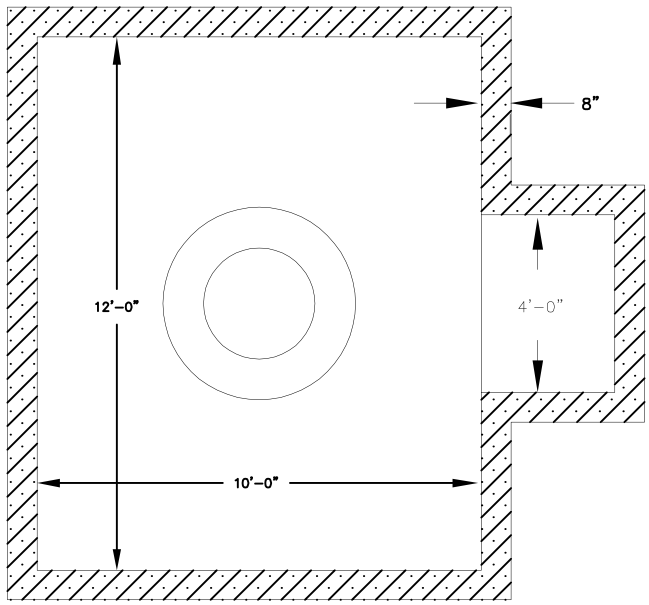
PUNA GEOTHERMAL VENTURE

DISTANCE FROM WELLHEADS TO NEAREST PGV LEASE BOUNDARY

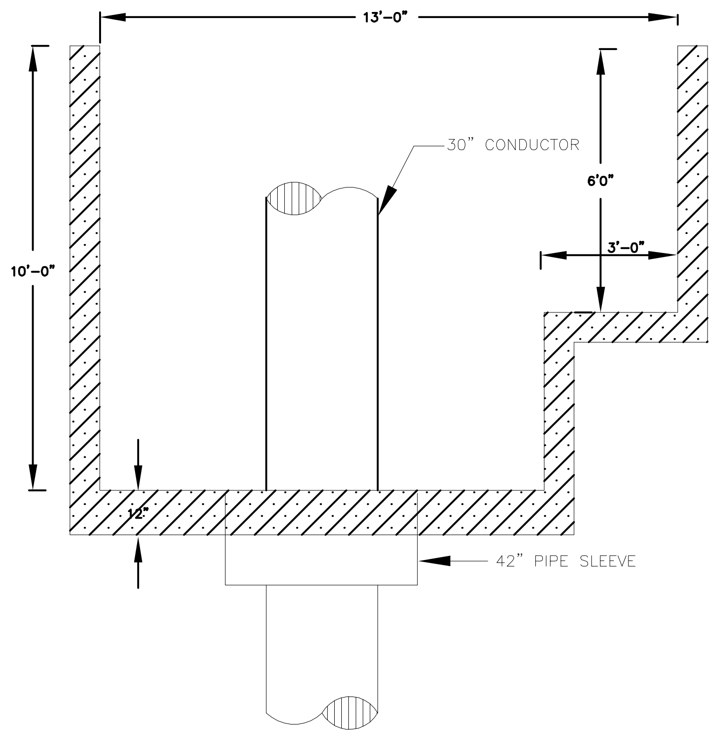
DATE: 12/7/2009

BY: WM. TEPLOW

FIGURE 1

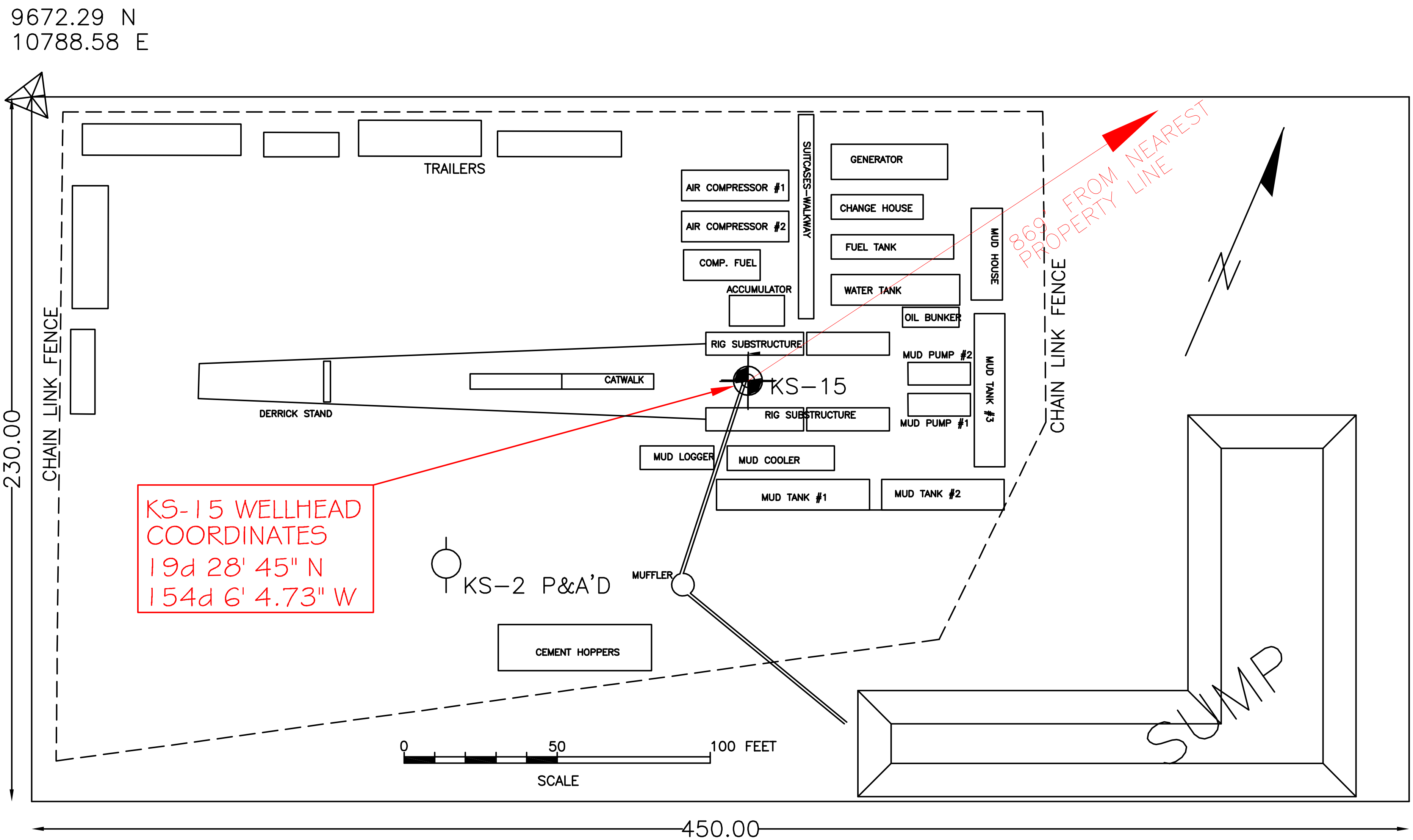


PLAN



VERTICAL SECTION

PUNA GEOTHERMAL VENTURE	GEOTHERMAL WELL KS–16 WELL CELLAR	DATE: 11/13/2014		FIGURE 3–1



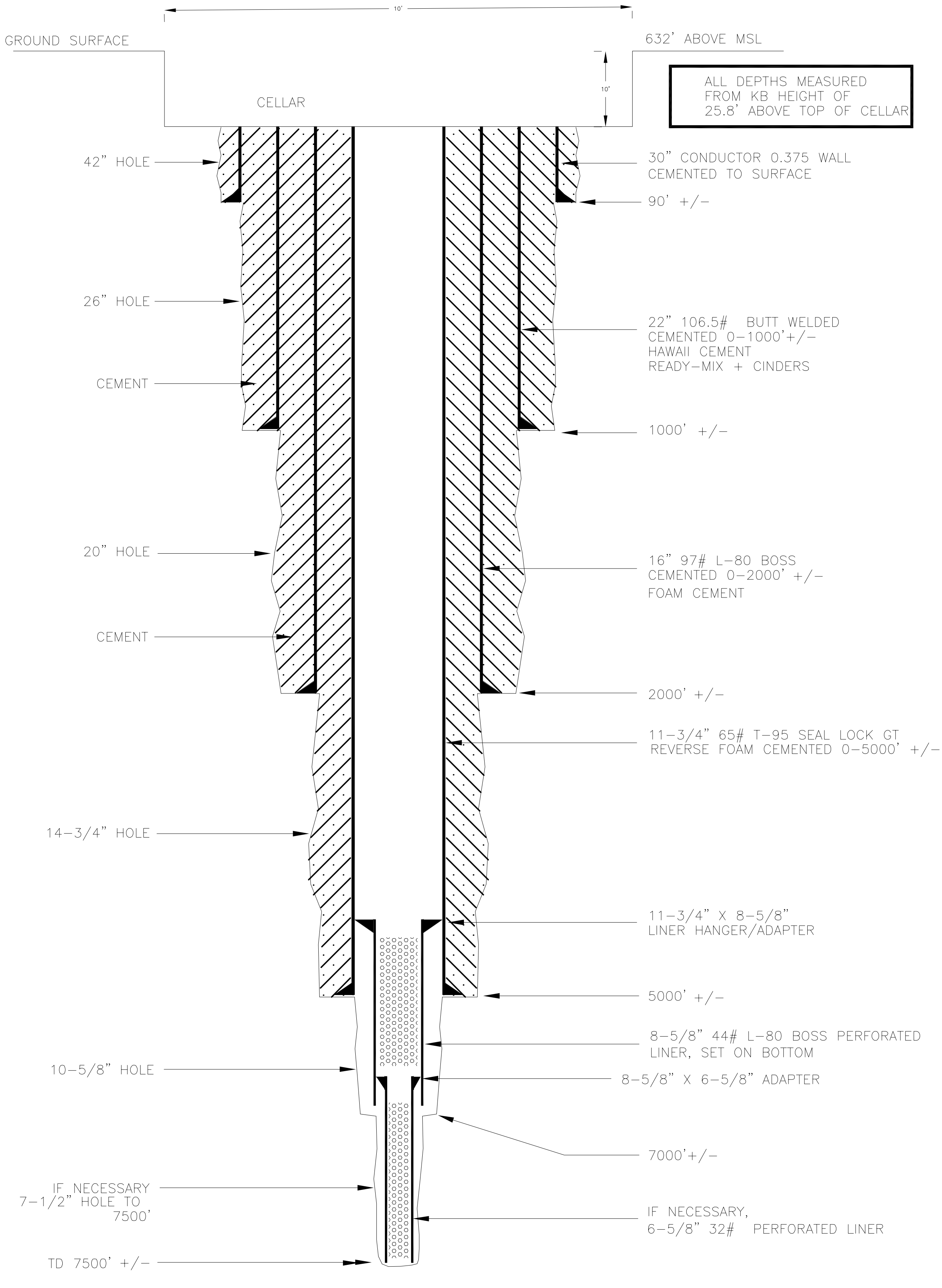
PUNA GEOTHERMAL VENTURE

GEOTHERMAL WELL KS-15
RIG LAYOUT

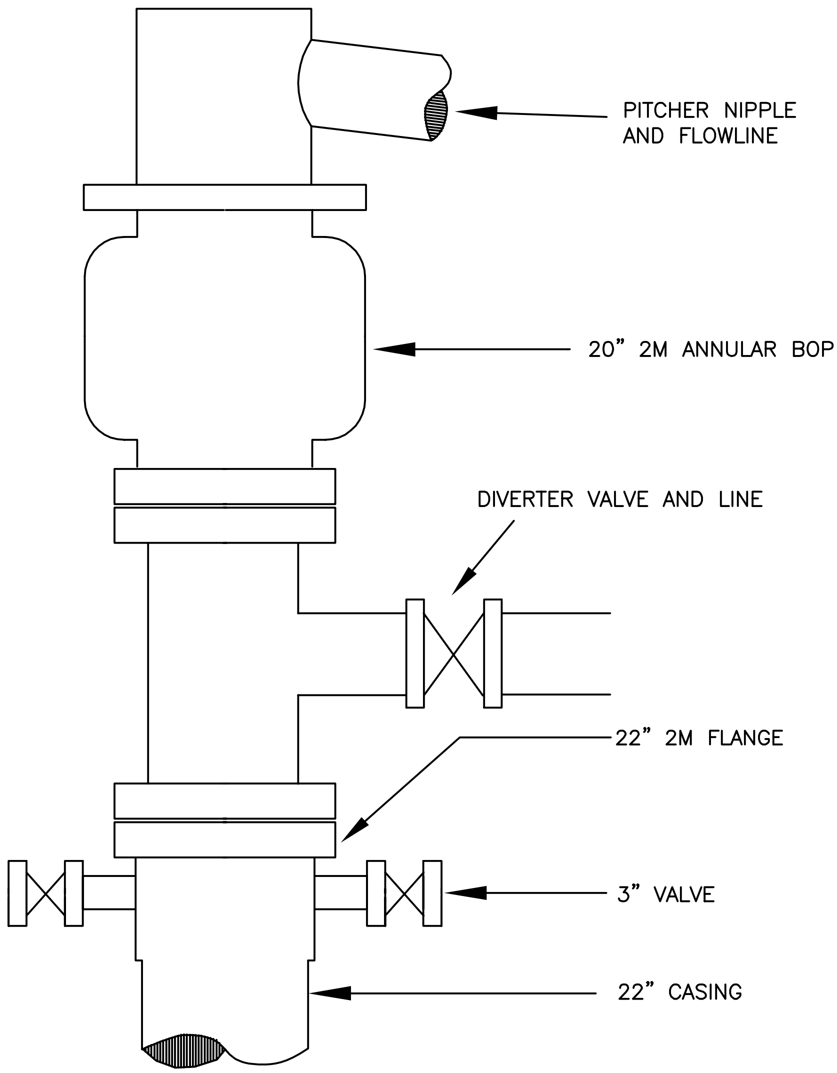
DATE: 5/10/2011

BY: WM. TEPLOW

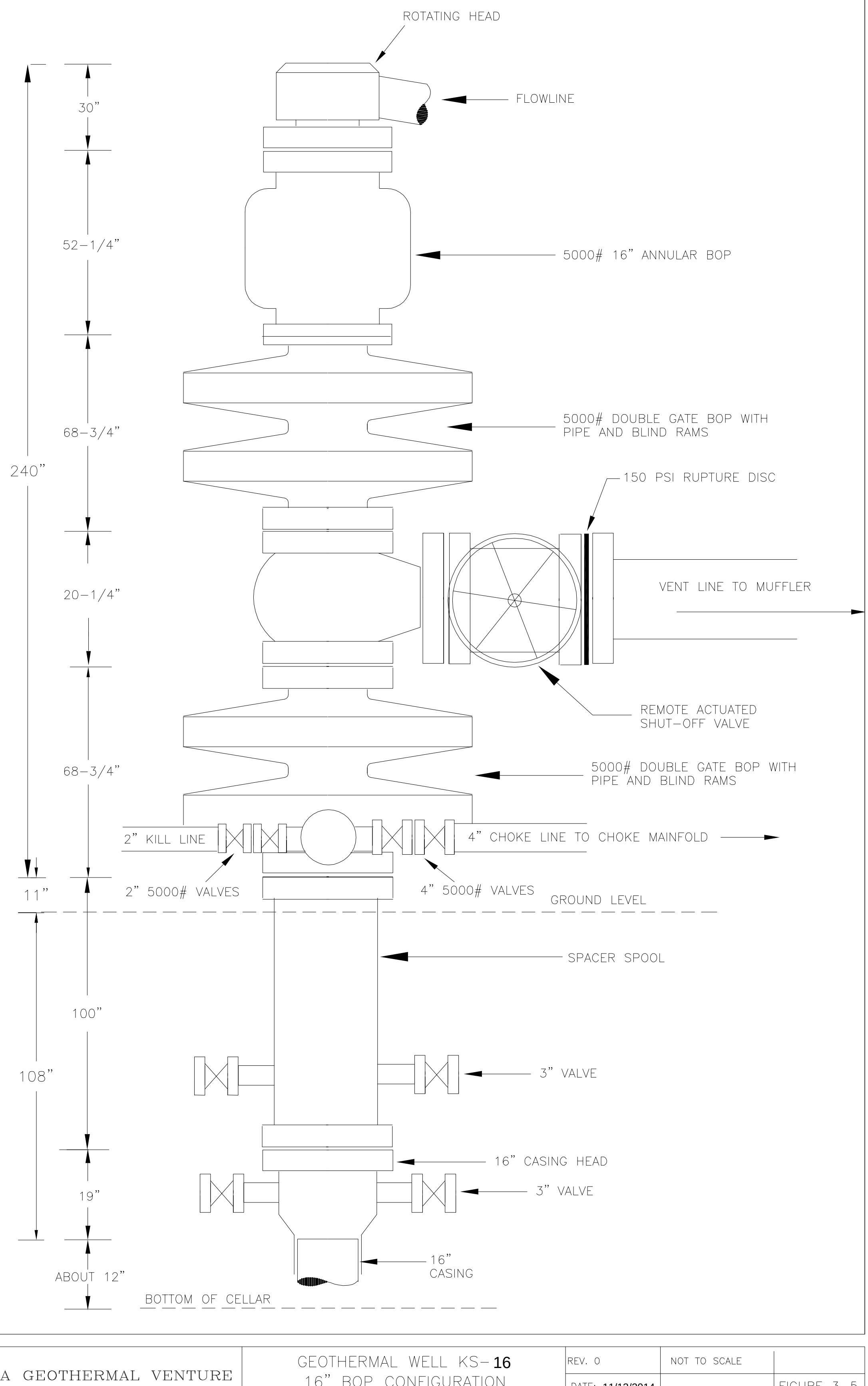
FIGURE 3-2



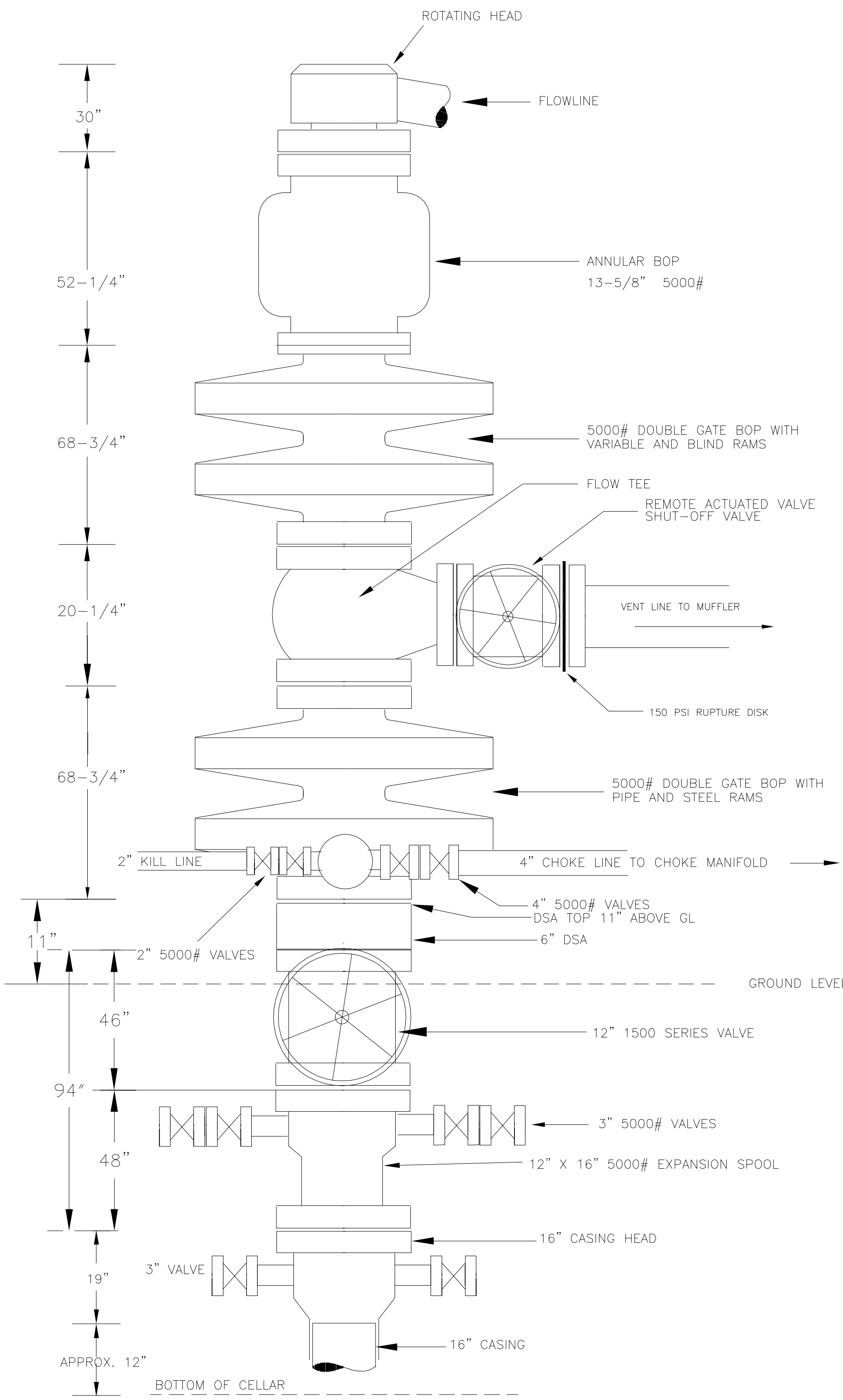
PUNA GEOTHERMAL VENTURE	GEOTHERMAL WELL KS-16 WELL DESIGN AND CASING SCHEMATIC	REV. 0	NOT TO SCALE	
		DATE: 11/13/2014		FIGURE 3-3



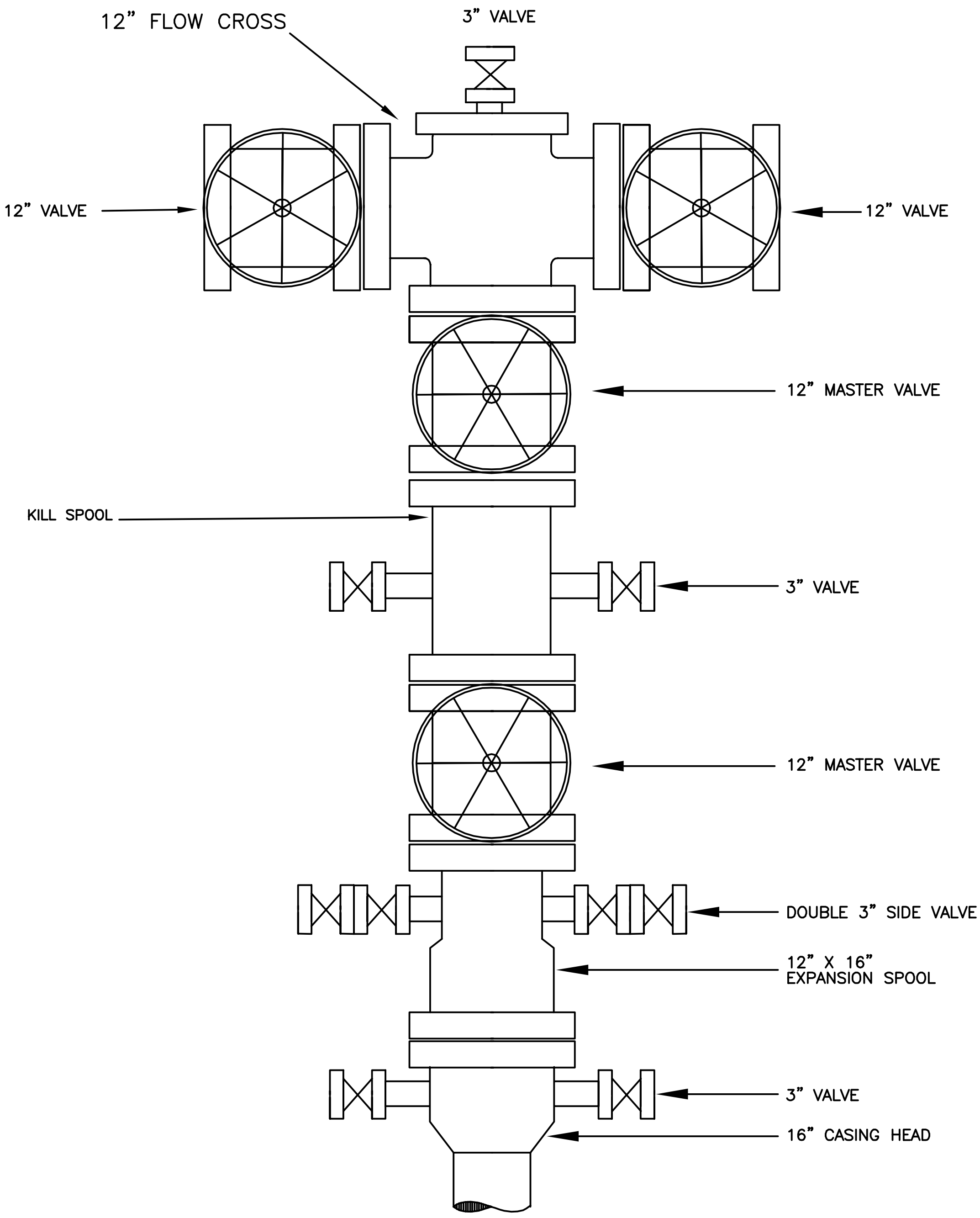
PUNA GEOTHERMAL VENTURE	GEOTHERMAL PRODUCTION WELL KS-16 20" BOP CONFIGURATION	DATE: 11/13/2014	BY:	FIGURE 3-4



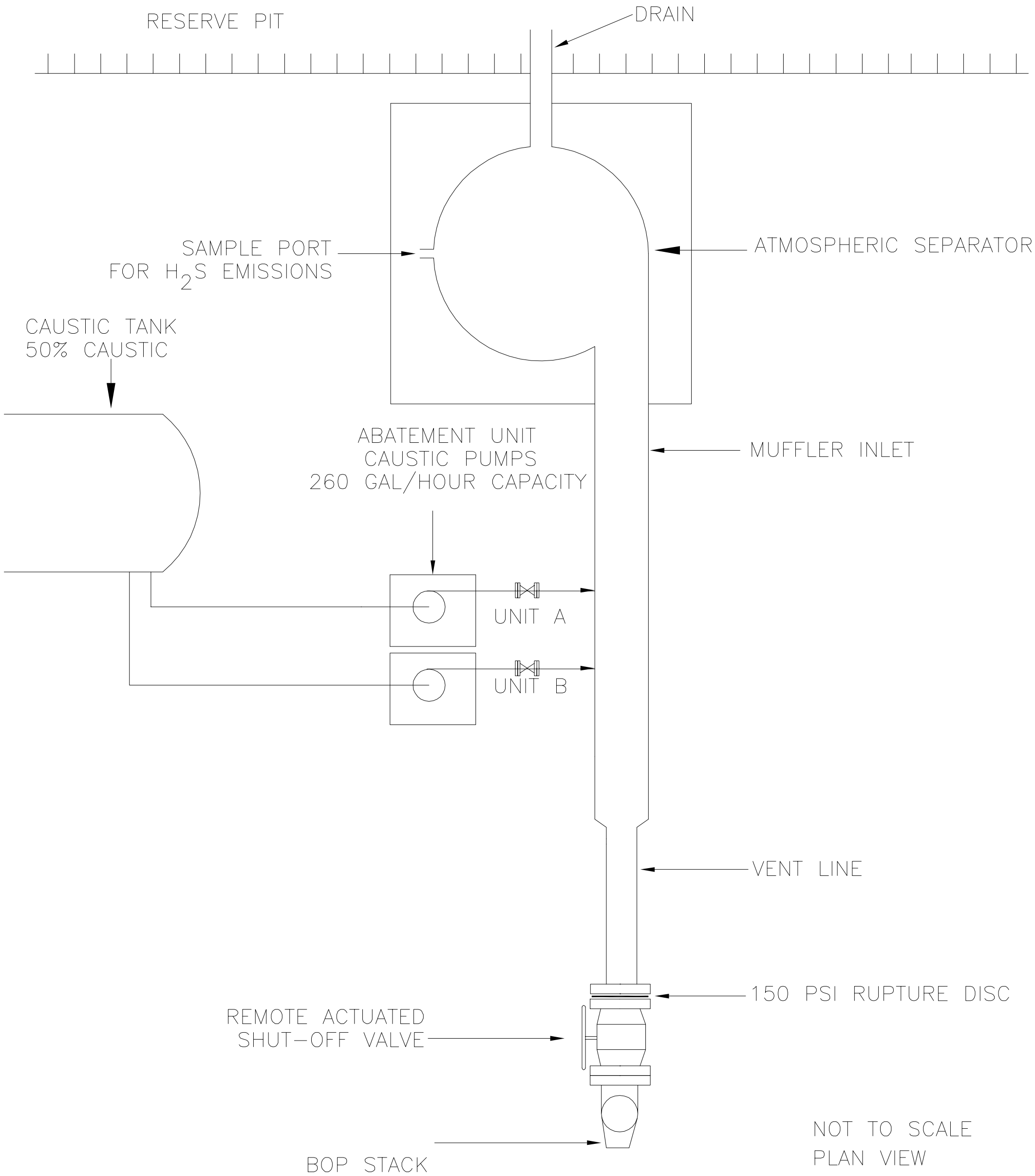
PUNA GEOTHERMAL VENTURE	GEOTHERMAL WELL KS-16 16" BOP CONFIGURATION	REV. 0	NOT TO SCALE	
		DATE: 11/13/2014		FIGURE 3-5



PUNA GEOTHERMAL VENTURE	GEOTHERMAL WELL KS- 16 11-3/4" BOP CONFIGURATION	REV. 0	NOT TO SCALE	
		DATE: 11/13/2014		FIGURE 3-6



PUNA GEOTHERMAL VENTURE	GEOTHERMAL WELL KS– 16 WELLHEAD CONFIGURATION	DATE: 11/13/2014	BY:	FIGURE 3–7



PUNA GEOTHERMAL VENTURE	GEOTHERMAL WELL KS– 16 MUFFLER AND ABATEMENT SYSTEM DURING DRILLING	DATE: 11/13/2014		FIGURE 3–8

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