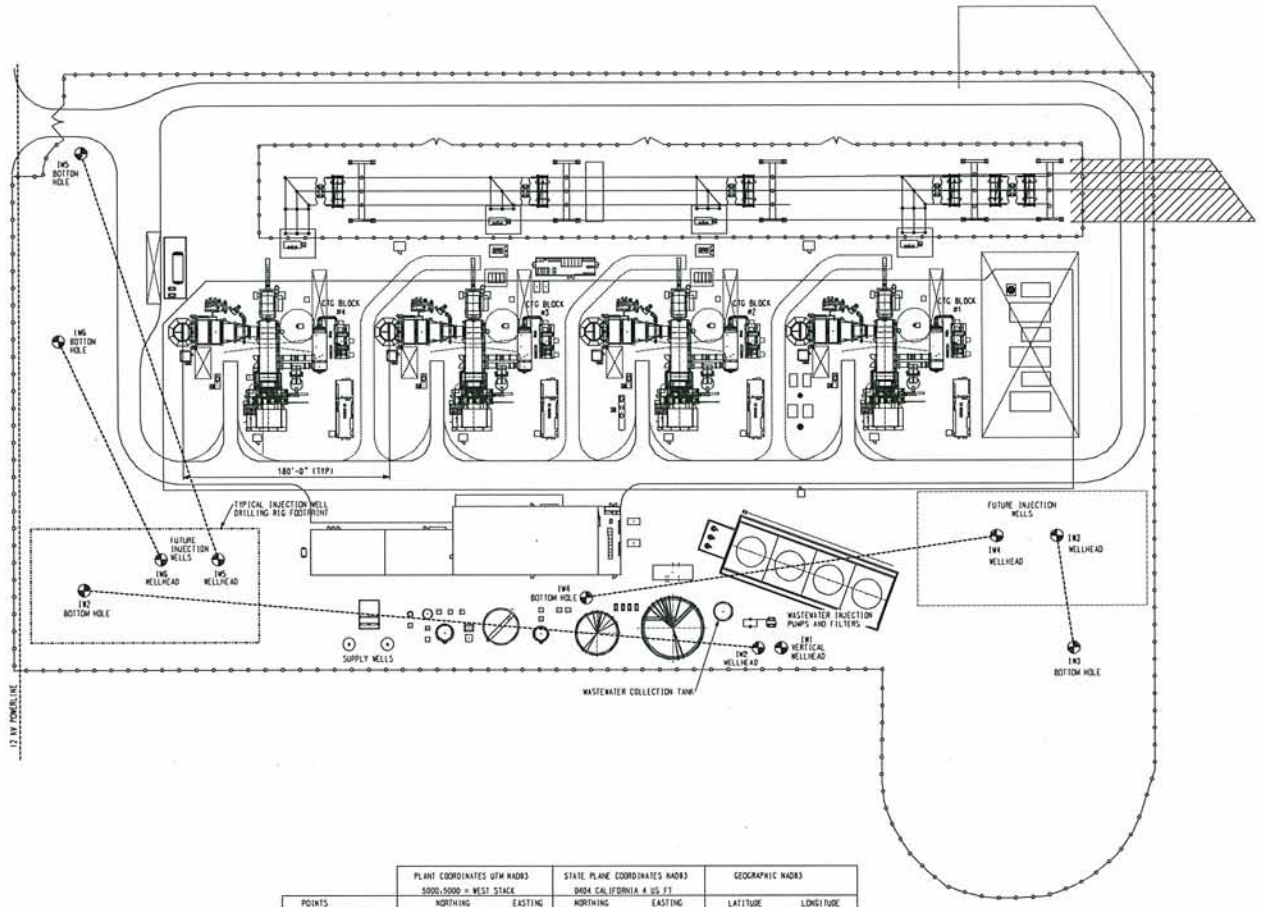
APPENDIX A - PROJECT MAPS

NOTES:

1. PROPOSED GENERAL LOCATIONS FOR THE INJECTION WELLS ARE SHOWN. THE WELLS MAY BE DRILLED IN ANY SEQUENCE AND WILL BE NUMBERED SERIALLY AS DRILLED. PERMITTEE MUST SUBMIT PROPOSED FIELD COORDINATES FOR APPROVAL PRIOR TO DRILLING ANY WELL.



	PLANT COORDINATES UTM NAD83 5000,5000 = WEST STACK		STATE PLANE COORDINATES NAD83 0404 CALIFORNIA # US FT		GEOGRAPHIC NAD83	
POINTS	NORTHING	EASTING	NORTHING	EASTING	LATITUDE	LONGITUDE
IW1 (Vertical)	4723.02	5522.79	2123809.58	6097078.53	36 39 02.3208	120 35 01.7812
IW2 WELLHEAD	4723.02	5502.79	2123809.58	6097056.53	36 39 02.3175	120 35 02.0266
IW2 BOTTOM HOLE	4774.19	4912.77	2123850.75	6096468.51	36 39 02.7272	120 35 09.2768
IW3 WELLHEAD	4820.72	5764.29	2123907.28	6097320.03	36 39 03.3252	120 34 58.8376
IW3 BOTTOM HOLE	4723.02	5778.84	2123809.58	6097334.58	36 39 02.3625	120 34 58.6393
IW4 WELLHEAD	4820.72	5711.57	2123907.28	6097267.31	36 39 03.3176	120 34 59.4846
IW4 BOTTOM HOLE	4767.28	5352.69	2123853.84	6096908.43	36 39 02.7307	120 35 03.8774
IW5 WELLHEAD	4800.88	5030.73	2123887.44	6096586.47	36 39 03.0104	120 35 07.8349
IW5 BOTTOM HOLE	5156.38	4911.31	2124242.94	6096467.05	36 39 06.5058	120 35 09.3722
IW6 WELLHEAD	4800.88	4980.73	2123887.44	6096536.47	36 39 03.0022	120 35 06.4484
IW6 BOTTOM HOLE	4951.76	4890.77	2124078.32	6096445.51	36 39 04.8748	120 35 09.5909
SUPPLY WELL WEST	4726.75	5143.95	2123813.31	6096699.89	36 39 02.2959	120 35 06.4305
SUPPLY WELL EAST	4726.75	5177.89	2123813.31	6096733.63	36 39 02.3014	120 35 06.0140

N

40 0 40 80
SCALE IN FEET
SCALE: 1" = 40'-0"

LEGEND

IW6 — WELLHEAD

IW6 — BOTTOM HOLE

IW2 — IW2 — DOTTED LINE REPRESENTS TYPICAL DIRECTIONAL DRILLING PATH.

- PRELIMINARY - NOT FOR CONSTRUCTION

CONFIDENTIAL

THESE DRAWINGS ARE CONFIDENTIAL IN NATURE, ANY METHOD OF UNAUTHORIZED DISTRIBUTION OF THE DRAWINGS CONTAINED HEREIN WILL BE A VIOLATION OF THIS CONFIDENTIALITY REQUIREMENT AND SUBJECT THE VIOLATOR TO LIABILITY. REVIEW OF THESE MATERIALS BY RECIPIENT SHALL CONSTITUTE AN ACCEPTANCE OF THESE TERMS AND THE TERMS OF ANY UNDERLYING CONFIDENTIALITY AGREEMENT. IF YOU HAVE RECEIVED IT DETACHED FROM A TRANSMITTAL LETTER, YOU ARE NOT AUTHORIZED TO USE THE DRAWINGS. UNDER THE CONFIDENTIALITY THEY THE DRAWINGS SHALL BE RETURNED TO KIEWIT POWER ENGINEERS.

REV	DESCRIPTION	DWN	CHK	APP	DATE
F	ISSUED FOR REVIEW	WFX			01-12-08
E	ISSUED FOR REVIEW	WFX			01-11-08
D	ISSUED FOR REVIEW	WFX			01-10-08
C	ISSUED FOR REVIEW	WFX			01-08-08
B	ISSUED FOR REVIEW	WFX			12-27-07
A	ISSUED FOR REVIEW	WFX			12-20-07

PANOCHE ENERGY CENTER, LLC

4 X GE LMS100 PEAKING FACILITY
FRESNO COUNTY, CALIFORNIA

Klewit

Kiewit Power
8555 Lenexa Drive
Lenexa, Kansas 66214

INJECTION WELL LOCATIONS AND DRILLING PLAN

	by	date
DESIGNED	WFX	12-20-07
DRAWN		
CHECKED		
APPROVED		

DRAWING NUMBER

SKM-200718-M-122007-1

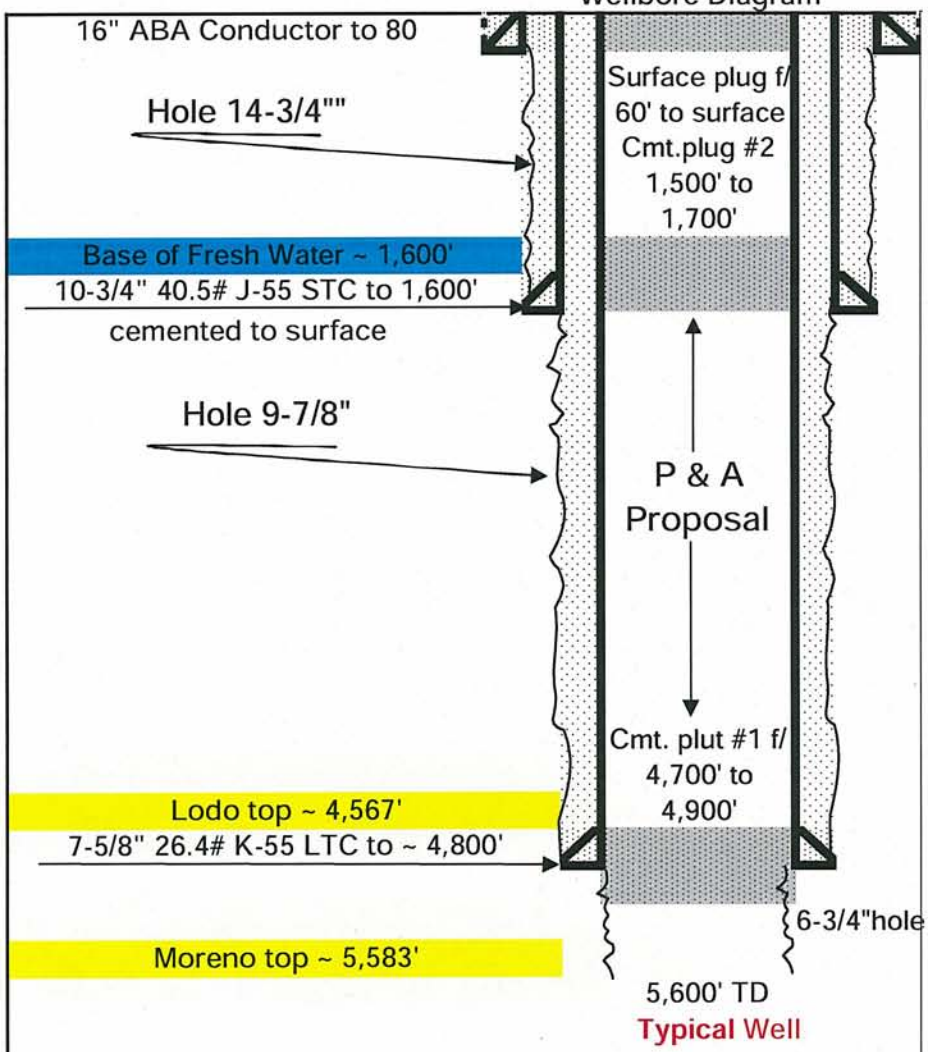
APPENDIX B – WELL SCHEMATICS

PLAN A

Well : IW1 - **IW6**

Surface Location: **See Plan**

Wellbore Diagram



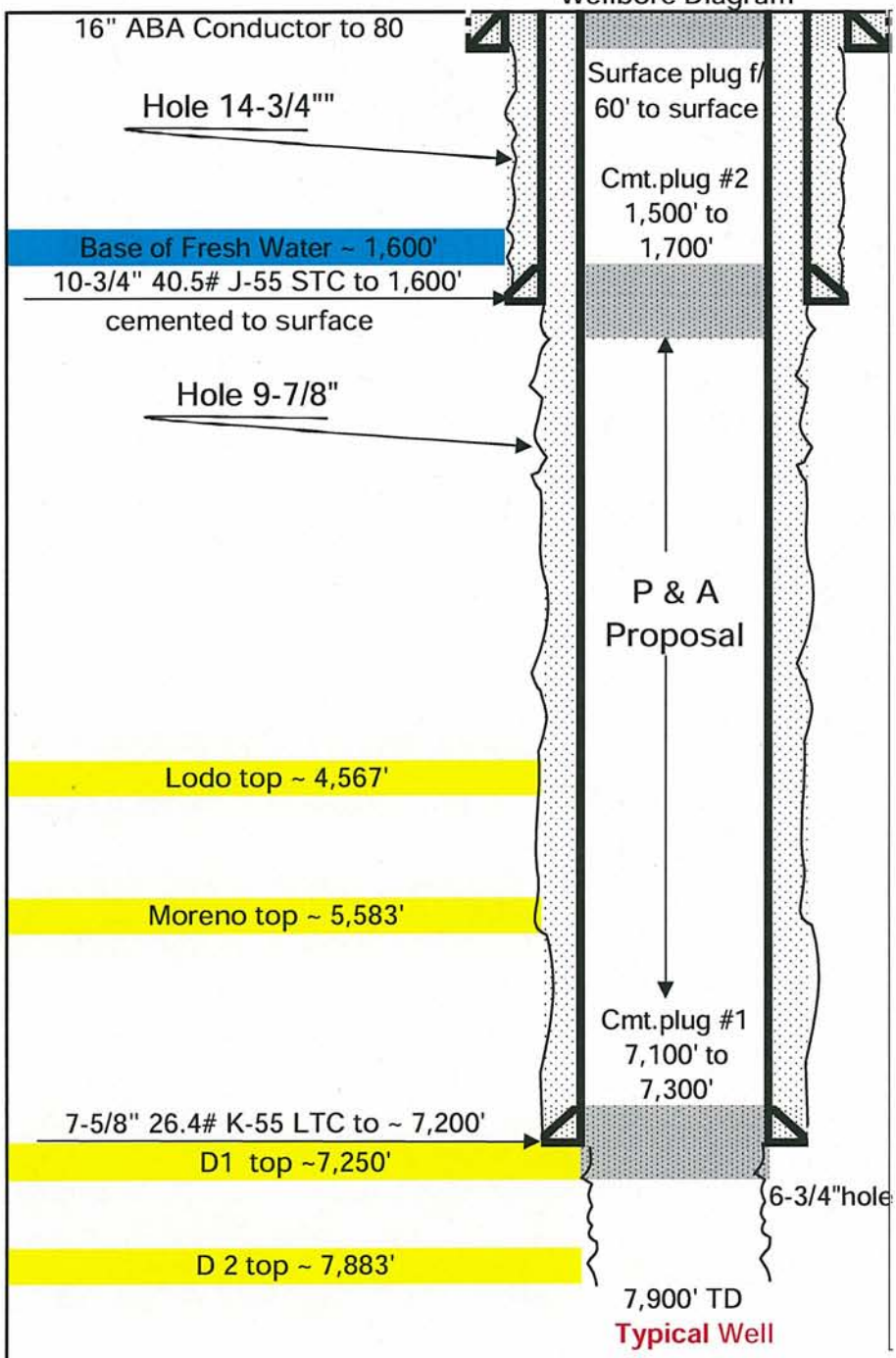
Hole Size	Depth	Casing
20"	80'	16" conductor
14-3/4"	1,600'	10-3/4", 40.5#, J-55, STC R3
9-7/8"	4,800'	7-5/8", 26.4#, K-55, LTC R3
6-3/4"	5,600'	5", 15#, K-55, LTC R3

PLAN B

Well : **IW1 - IW6**

Surface Location: **See Plan**

Wellbore Diagram



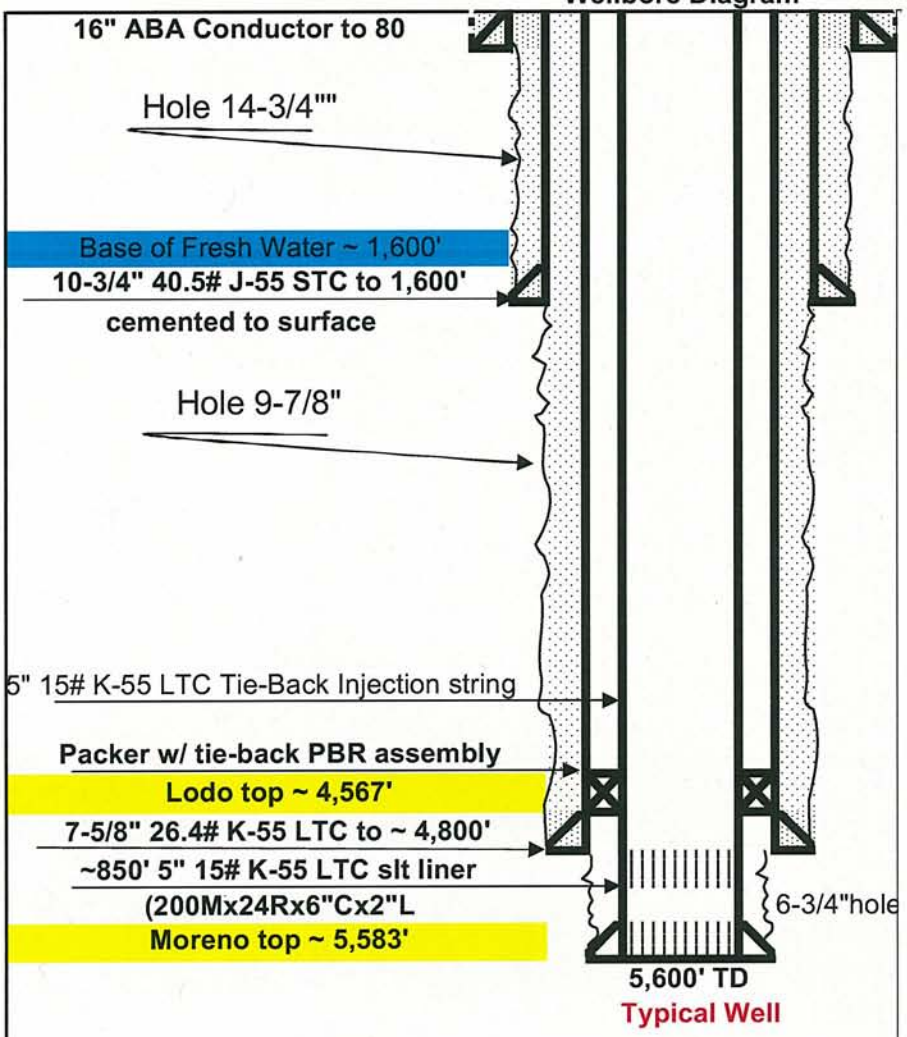
Hole Size	Depth	Casing
20"	80'	16" conductor
14-3/4"	1,600'	10-3/4", 40.5#, J-55, STC R3
9-7/8"	7,200'	7-5/8", 26.4#, K-55, LTC R3
6-3/4"	7,900'	5", 15#, K-55, LTC R3

PLAN A

Well : IW1 - IW6

Surface Location: See Plan

Wellbore Diagram



D1 top ~7,250'

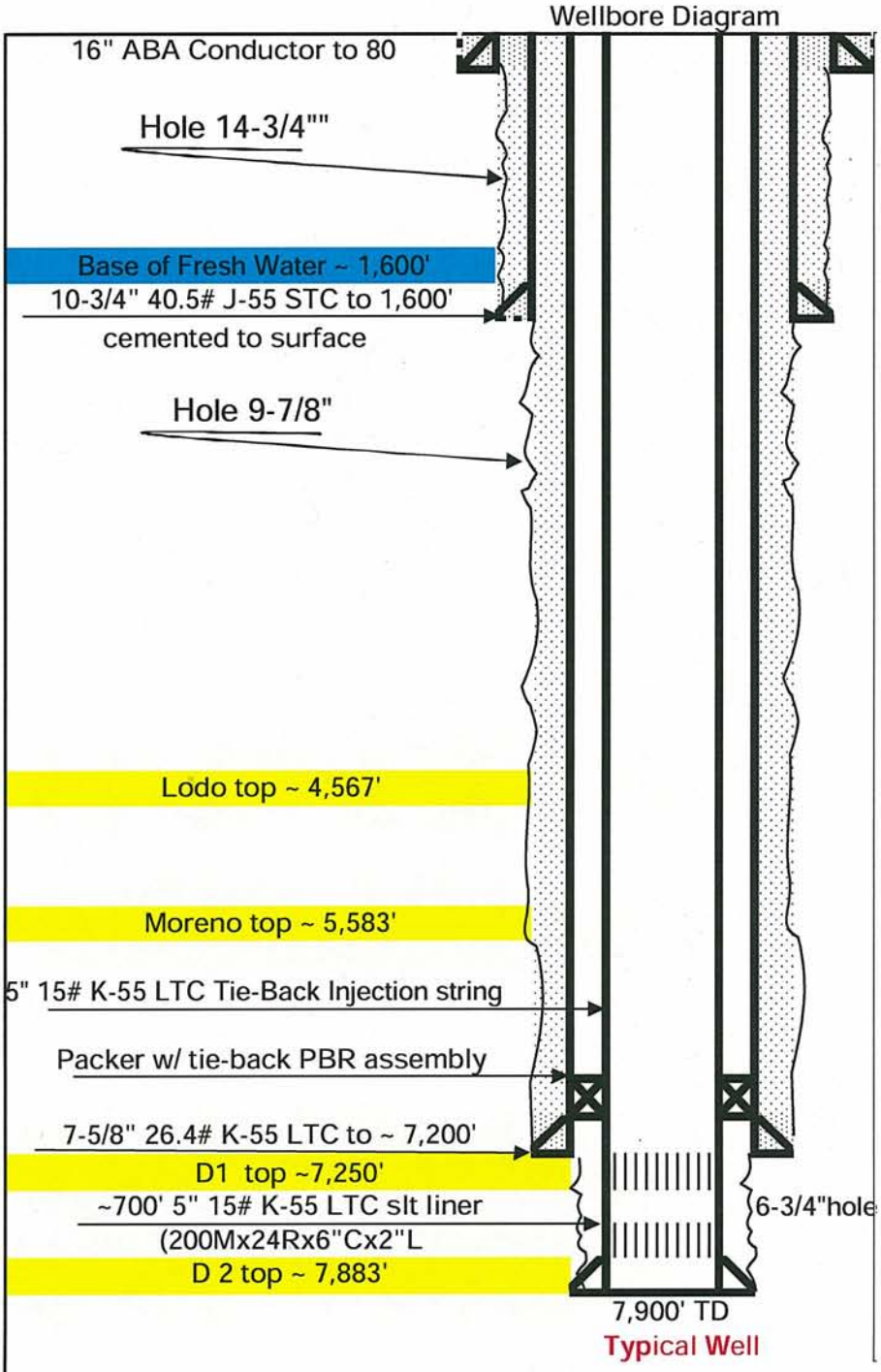
D 2 top ~ 7,883'

Hole Size	Depth	Casing
20"	80'	16" conductor
14-3/4"	1,600'	10-3/4", 40.5#, J-55, STC R3
9-7/8"	4,800'	7-5/8", 26.4#, K-55, LTC R3
6-3/4"	5,600'	5", 15#, K-55, LTC R3

PLAN B

Well : **IW1 - IW6**

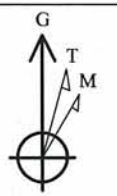
Surface Location: **See Plan**



Hole Size	Depth	Casing
20"	80'	16" conductor
14-3/4"	1,600'	10-3/4", 40.5#, J-55, STC R3
9-7/8"	7,200'	7-5/8", 26.4#, K-55, LTC R3
6-3/4"	7,900'	5", 15#, K-55, LTC R3

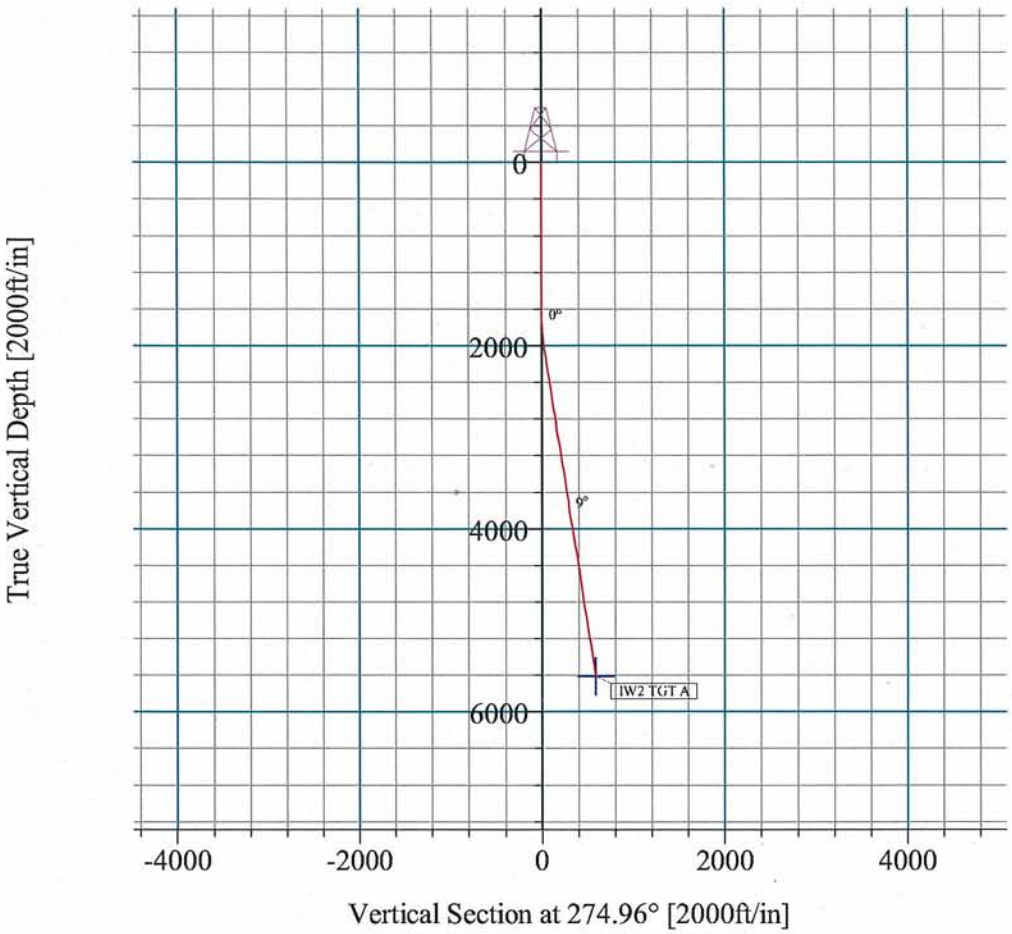
PANOCHE ENERGY, LLC

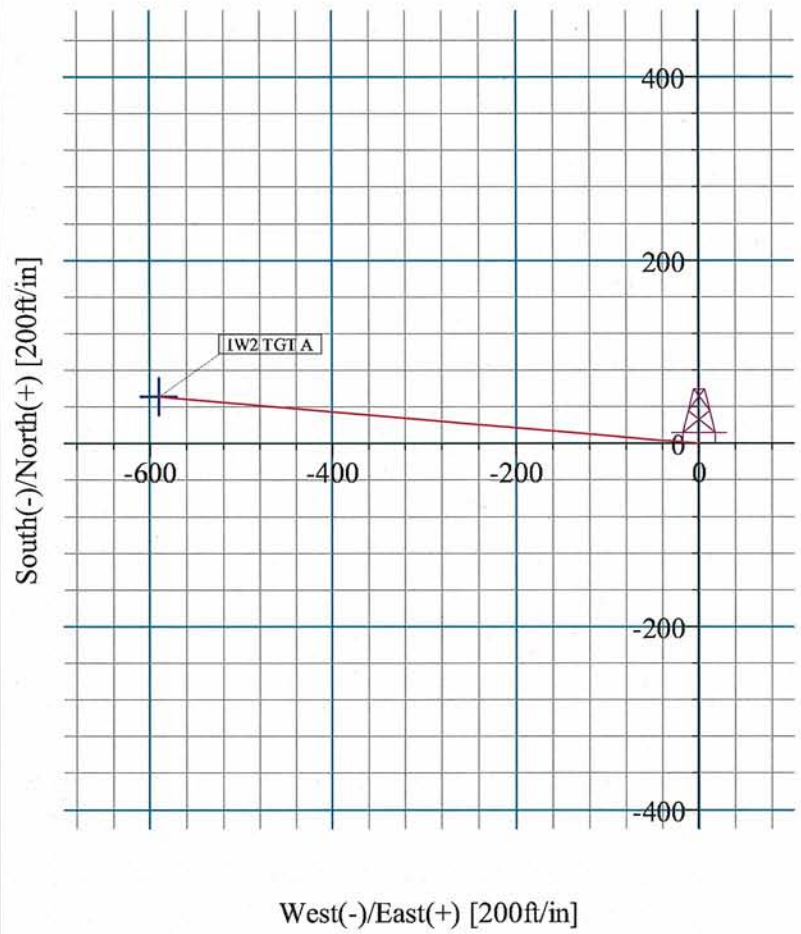
Field: CHENEY RANCH
Site: SECTION 5
Well: IW2
Wellpath: IW2 PLAN A
Plan: Plan A 011208V2



Azimuths to Grid North
True North: 0.94°
Magnetic North: 14.93°

Magnetic Field
Strength: 48906nT
Dip Angle: 60.72°
Date: 1/12/2008
Model: igrf2005





TARGET DETAILS

Name	TVD	+N/-S	+E/-W	Shape
IW2 TGT A	5612.00	51.17	-590.02	Point

Scientific Drilling
West Coast Operations

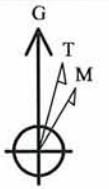
KOP 1670'
DOG LEG RATE 3°/100'
TAR. POINT

SECTION DETAILS

Sec	MD	Inc	Azi	TVD	+N/-S	+E/-W	DLeg	TFace	VSec	Target
1	0.00	0.00	274.96	0.00	0.00	0.00	0.00	0.00	0.00	
2	1670.00	0.00	274.96	1670.00	0.00	0.00	0.00	0.00	0.00	
3	1965.75	8.87	274.96	1964.57	1.97	-22.77	3.00	274.96	22.85	
4	5657.35	8.87	274.96	5612.00	51.17	-590.02	0.00	0.00	592.23	IW2 TGT A

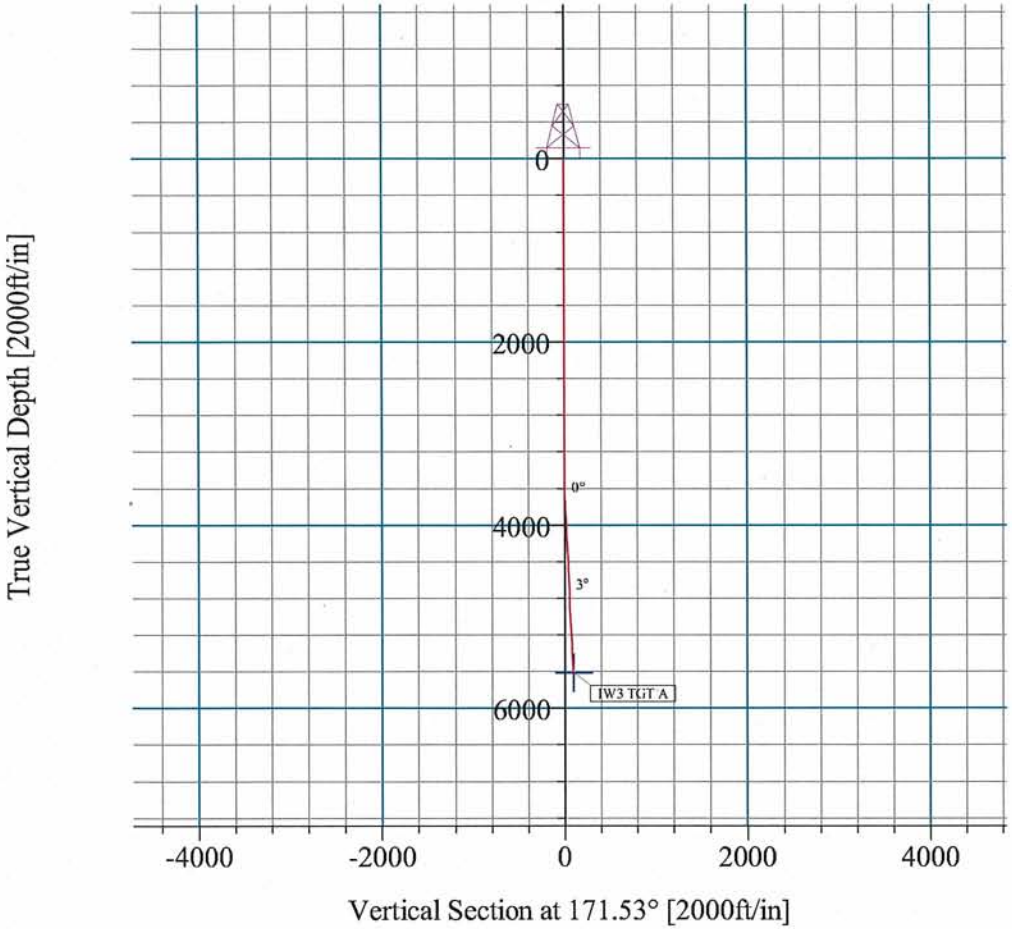
PANOCHE ENERGY, LLC

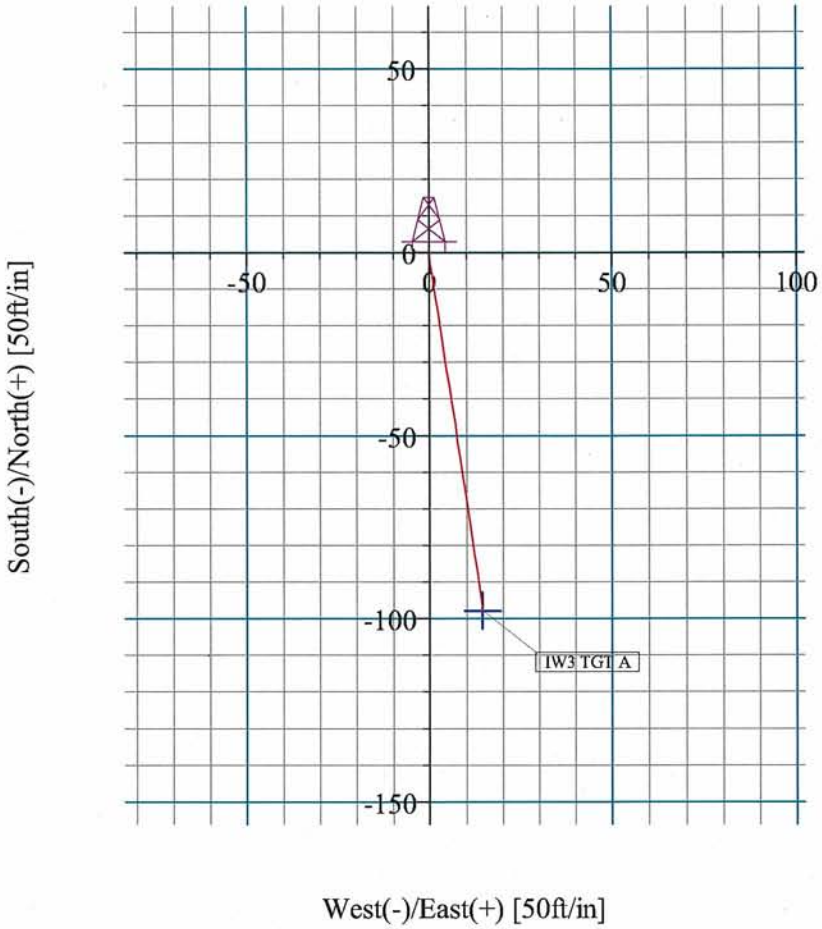
Field: CHENEY RANCH
Site: SECTION 5
Well: IW3
Wellpath: IW3 PLAN A
Plan: Plan A 011208V1



Azimuths to Grid North
True North: 0.94°
Magnetic North: 14.93°

Magnetic Field
Strength: 48906nT
Dip Angle: 60.72°
Date: 1/12/2008
Model: igrf2005





TARGET DETAILS

Name	TVD	+N/-S	+E/-W	Shape
IW3 TGT A	5612.00	-97.70	14.55	Point

Scientific Drilling
West Coast Operations

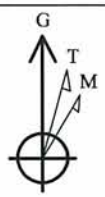
KOP 3600'
DOG LEG RATE 2°/100'
TAR. POINT

SECTION DETAILS

Sec	MD	Inc	Azi	TVD	+N/-S	+E/-W	DLeg	TFace	VSec	Target
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
2	3600.00	0.00	0.00	3600.00	0.00	0.00	0.00	0.00	0.00	
3	3745.81	2.92	171.53	3745.74	-3.67	0.55	2.00	171.53	3.71	
4	5614.48	2.92	171.53	5612.00	-97.70	14.55	0.00	0.00	98.78	IW3 TGT A

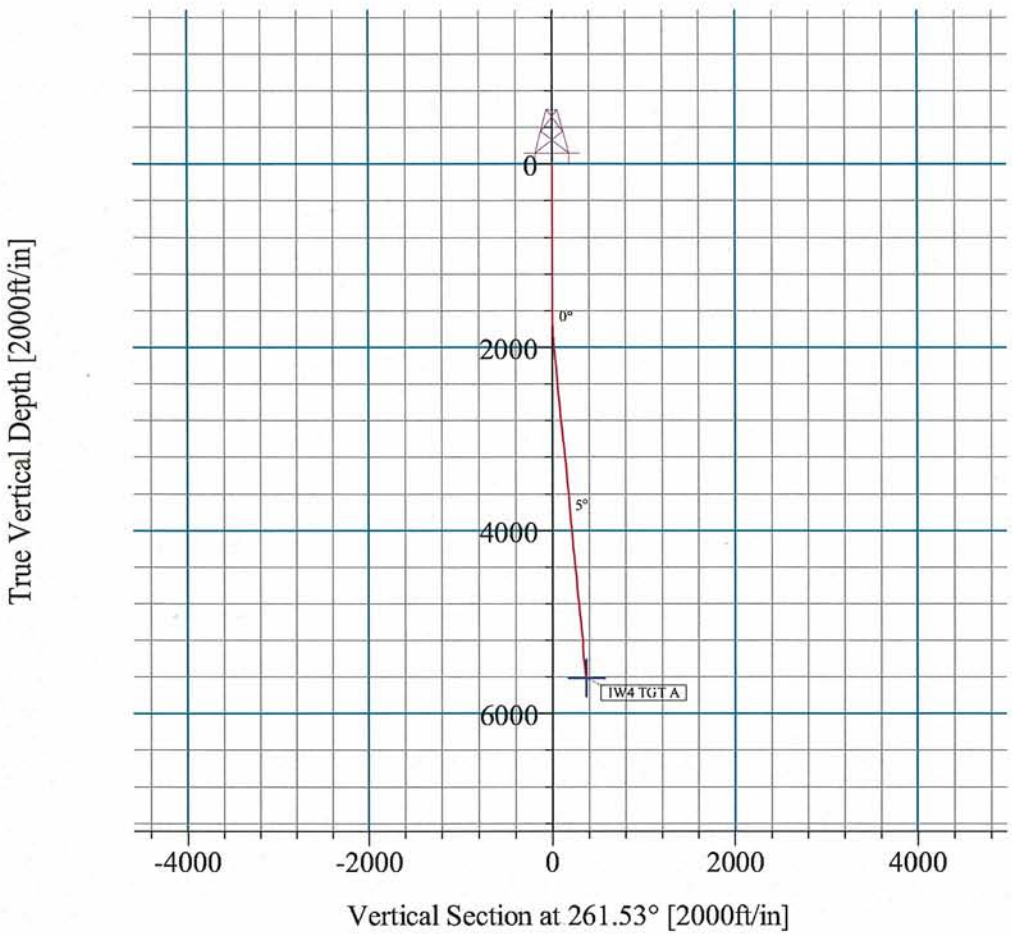
PANOCHE ENERGY, LLC

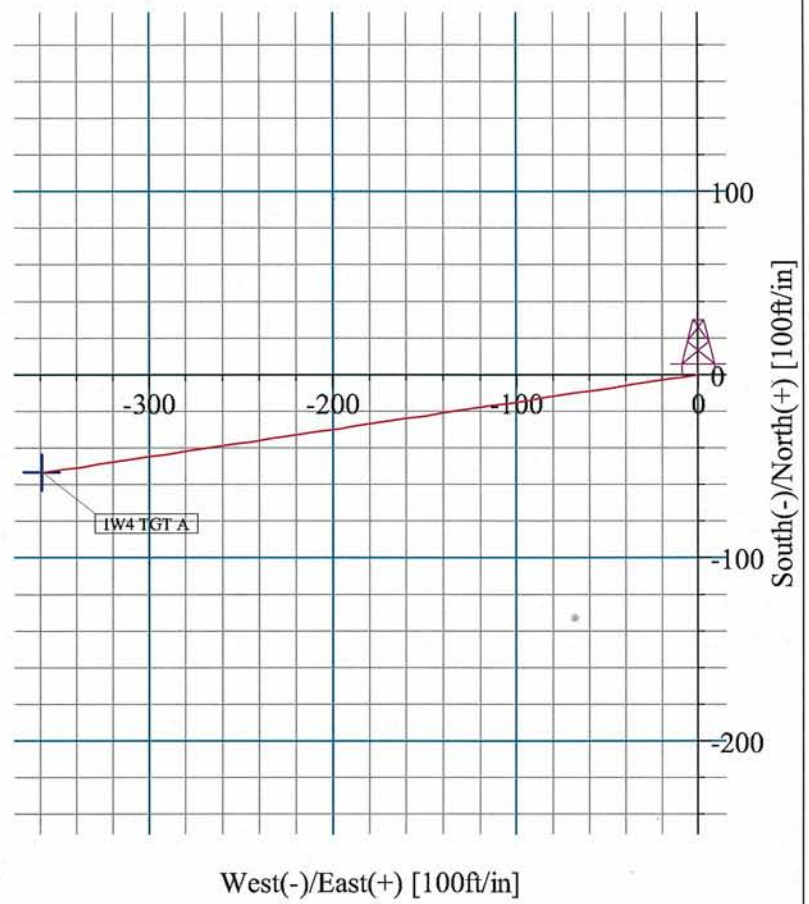
Field: CHENEY RANCH
Site: SECTION 5
Well: IW4
Wellpath: IW4 PLAN A
Plan: Plan A 011208V2



Azimuths to Grid North
True North: 0.94°
Magnetic North: 14.93°

Magnetic Field
Strength: 48906nT
Dip Angle: 60.72°
Date: 1/12/2008
Model: igrf2005





TARGET DETAILS

Name	TVD	+N/-S	+E/-W	Shape
IW4 TGT A	5612.00	-53.44	-358.88	Point

Scientific Drilling
West Coast Operations

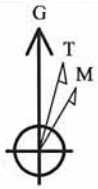
KOP 1670'
DOG LEG RATE 2°/100'
TAR. POINT

SECTION DETAILS

Sec	MD	Inc	Azi	TVD	+N/-S	+E/-W	DLeg	TFace	VSec	Target
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
2	1670.00	0.00	0.00	1670.00	0.00	0.00	0.00	0.00	0.00	
3	1942.30	5.45	261.53	1941.89	-1.90	-12.79	2.00	261.53	12.93	
4	5629.05	5.45	261.53	5612.00	-53.44	-358.88	0.00	0.00	362.84	IW4 TGT A

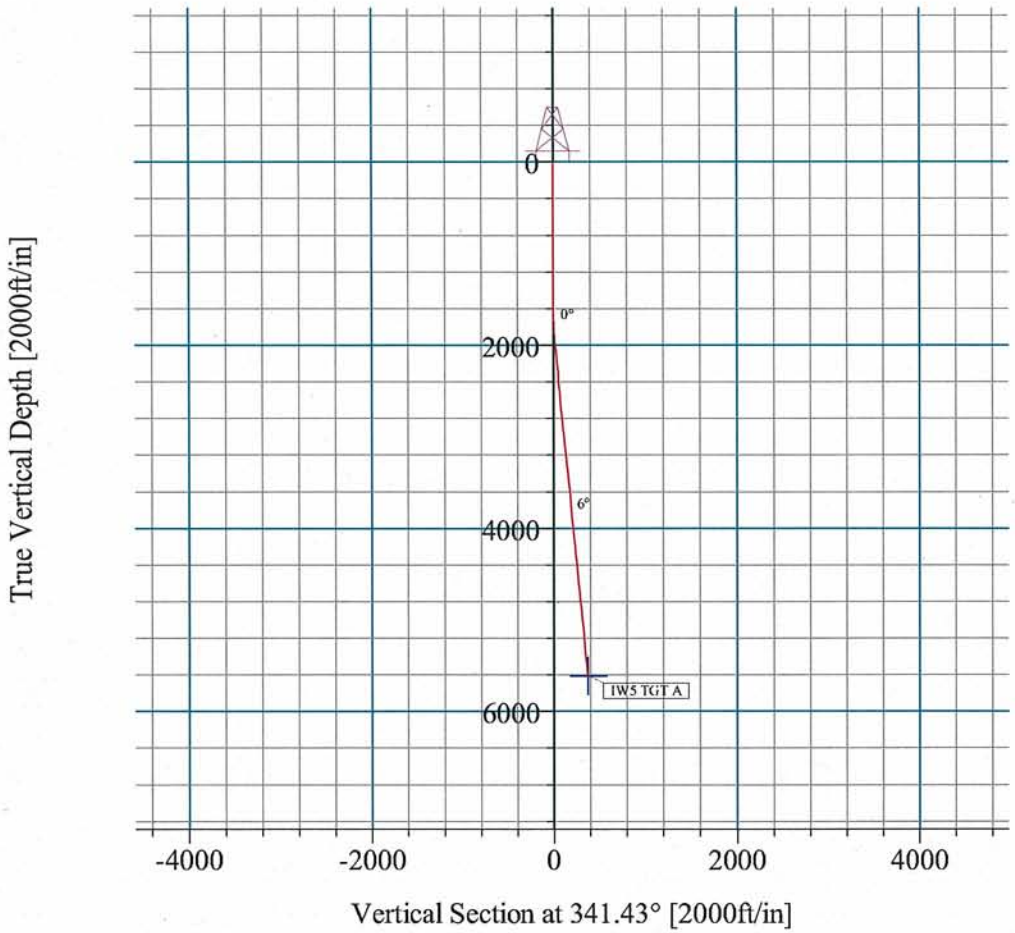
PANOCHE ENERGY, LLC

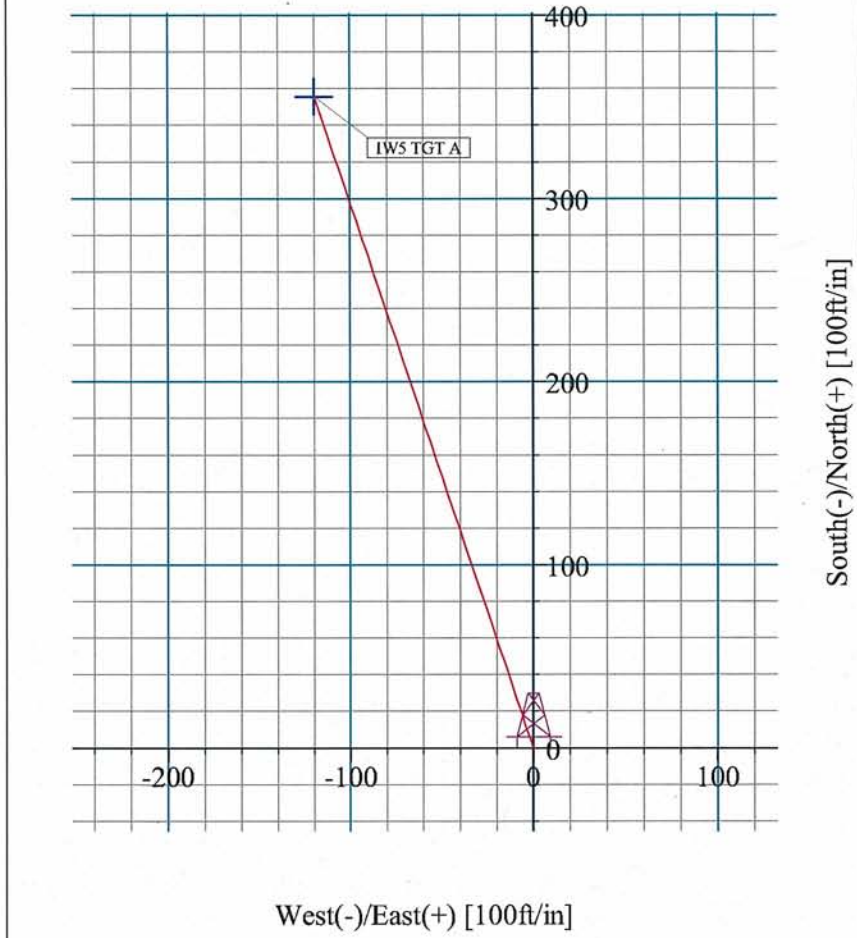
Field: CHENEY RANCH
Site: SECTION 5
Well: IW5
Wellpath: IW5 PLAN A
Plan: Plan A 011208V2



Azimuths to Grid North
True North: 0.95°
Magnetic North: 14.93°

Magnetic Field
Strength: 48906nT
Dip Angle: 60.72°
Date: 1/12/2008
Model: igrf2005





TARGET DETAILS

Name	TVD	+N/-S	+E/-W	Shape
IW5 TGT A	5612.00	355.50	-119.42	Point

Scientific Drilling
West Coast Operations

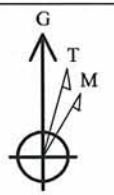
KOP 1670'
DOG LEG RATE 2°/100'
TAR. POINT

SECTION DETAILS

Sec	MD	Inc	Azi	TVD	+N/-S	+E/-W	DLeg	TFace	VSec	Target
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
2	1670.00	0.00	0.00	1670.00	0.00	0.00	0.00	0.00	0.00	
3	1951.74	5.63	341.43	1951.28	13.12	-4.41	2.00	341.43	13.84	
4	5630.23	5.63	341.43	5612.00	355.50	-119.42	0.00	0.00	375.02	IW5 TGT A

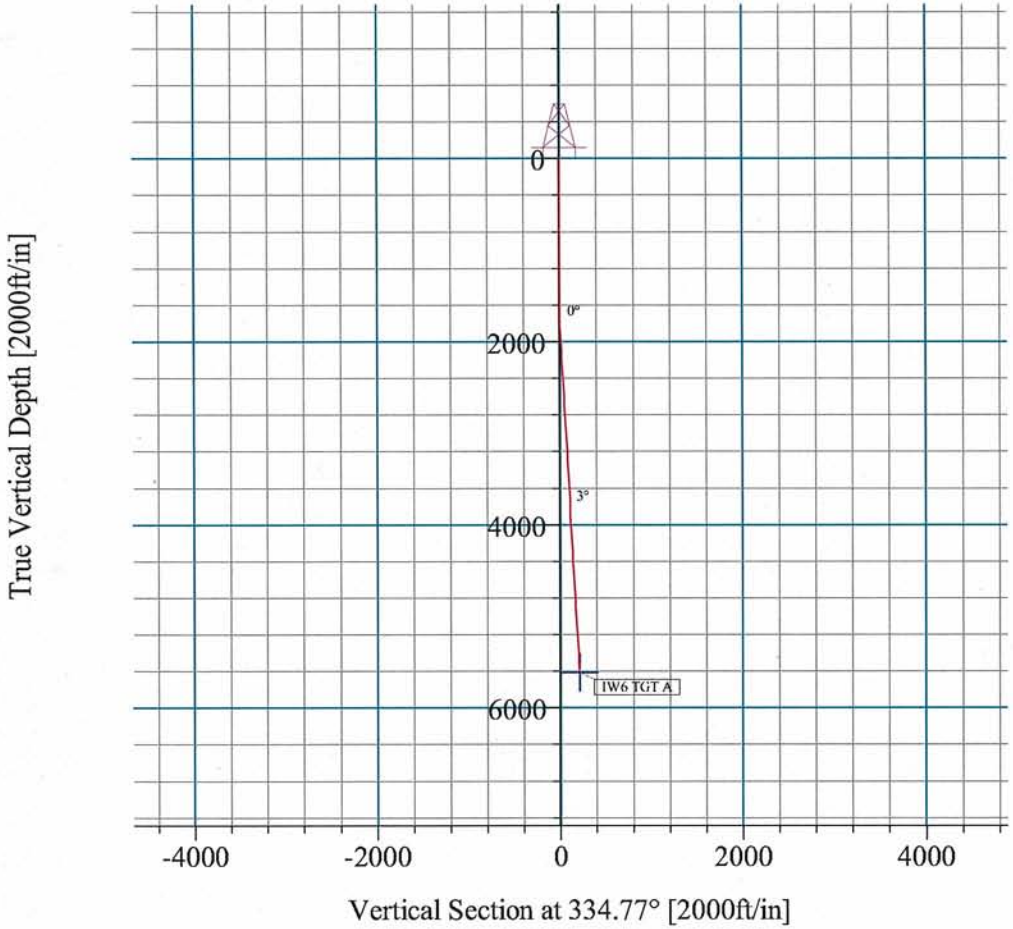
PANOCHE ENERGY, LLC

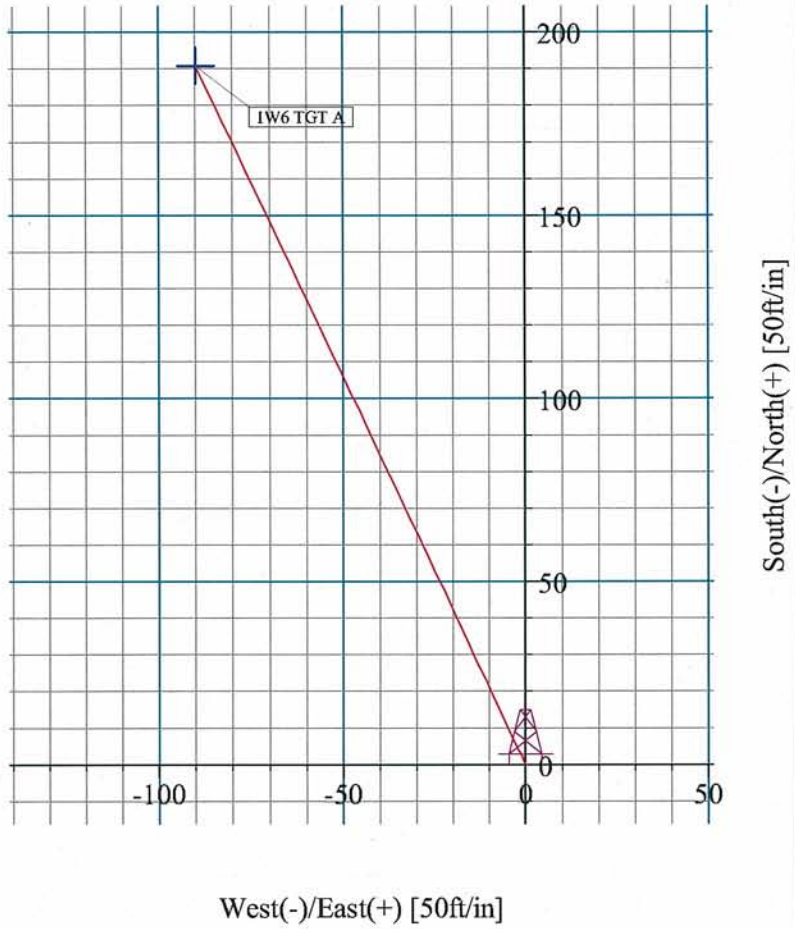
Field: CHENEY RANCH
Site: SECTION 5
Well: IW6
Wellpath: IW6 PLAN A
Plan: Plan A 011208V2



Azimuths to Grid North
True North: 0.95°
Magnetic North: 14.93°

Magnetic Field
Strength: 48906nT
Dip Angle: 60.72°
Date: 1/12/2008
Model: igrf2005





TARGET DETAILS

Name	TVD	+N/-S	+E/-W	Shape
IW6 TGT A	5612.00	190.88	-89.96	Point

Scientific Drilling
West Coast Operations

KOP 1670'
DOG LEG RATE 2°/100'
TAR. POINT

SECTION DETAILS

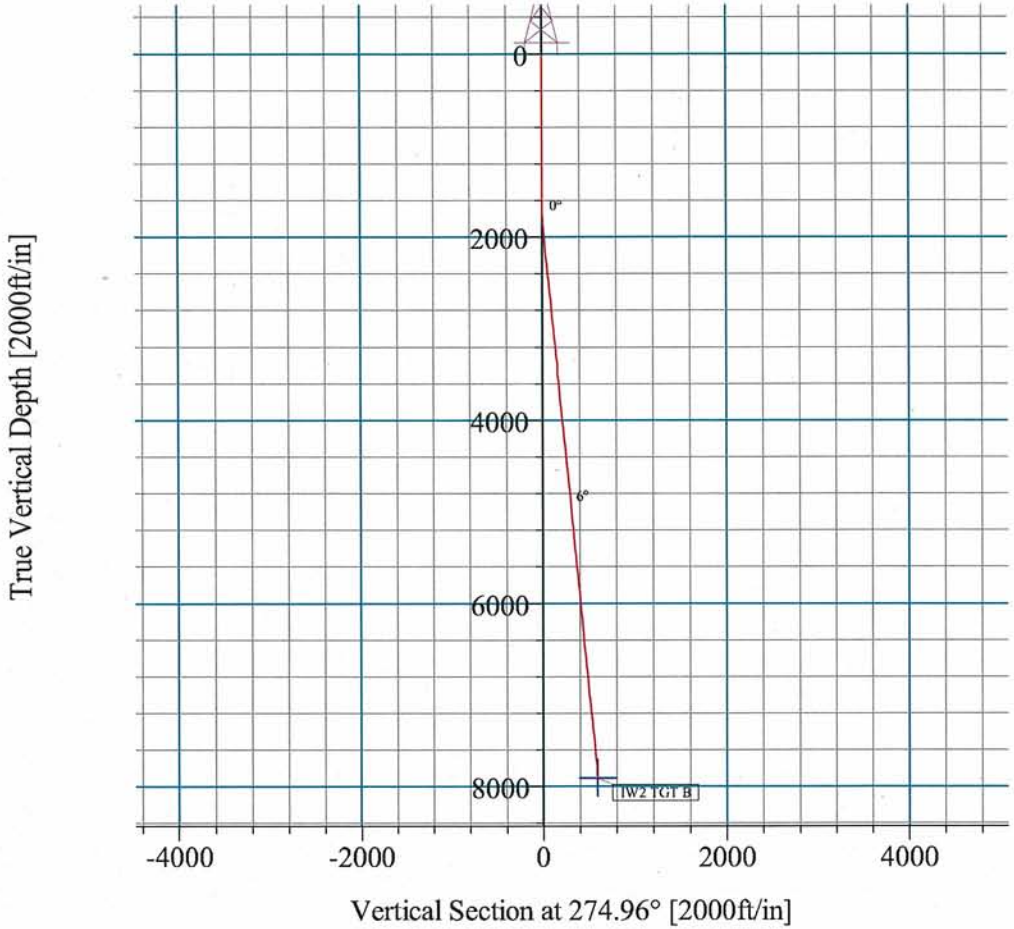
Sec	MD	Inc	Azi	TVD	+N/-S	+E/-W	DLeg	TFace	VSec	Target
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
2	1670.00	0.00	0.00	1670.00	0.00	0.00	0.00	0.00	0.00	
3	1826.30	3.13	334.77	1826.22	3.86	-1.82	2.00	334.77	4.26	
4	5617.72	3.13	334.77	5612.00	190.88	-89.96	0.00	0.00	211.02	IW6 TGT A

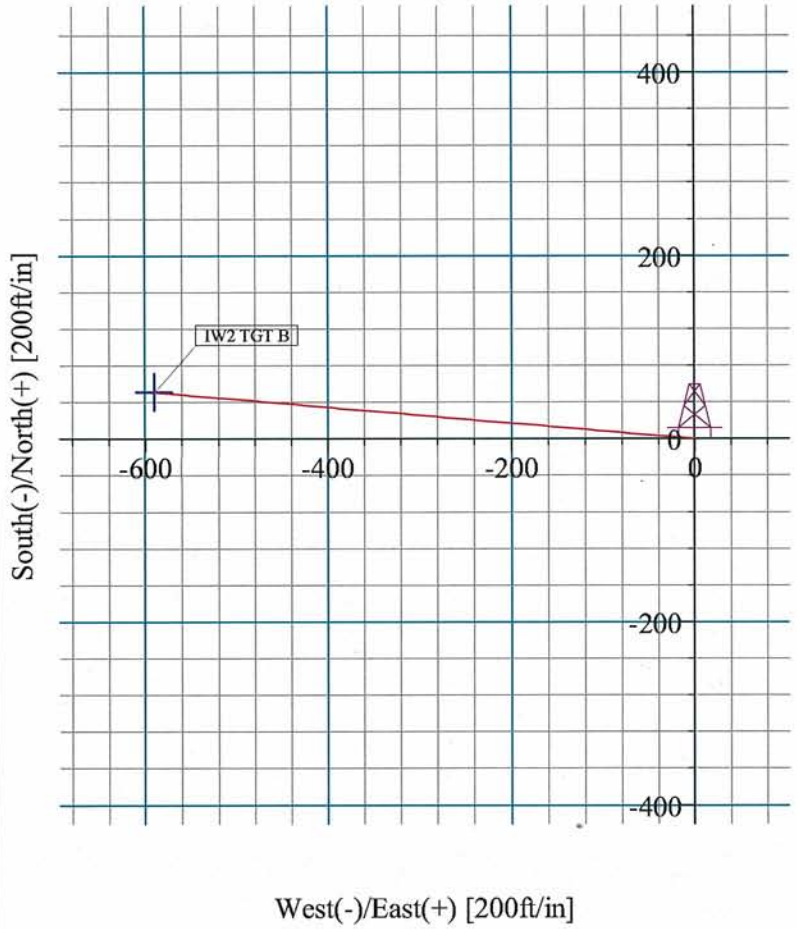
PANOCHE ENERGY, LLC

Field: CHENEY RANCH
Site: SECTION 5
Well: IW2
Wellpath: IW2 PLAN B
Plan: Plan B 011208V2

Azimuths to Grid North
True North: 0.94°
Magnetic North: 14.93°

Magnetic Field
Strength: 48906nT
Dip Angle: 60.72°
Date: 1/12/2008
Model: igrf2005





TARGET DETAILS

Name	TVD	+N/-S	+E/-W	Shape
IW2 TGT B	7912.00	51.17	-590.02	Point

Scientific Drilling
West Coast Operations

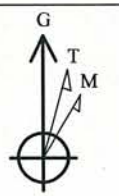
KOP 1670'
DOG LEG RATE 3°/100'
TAR. POINT

SECTION DETAILS

Sec	MD	Inc	Azi	TVD	+N/-S	+E/-W	DLeg	TFace	VSec	Target
1	0.00	0.00	274.96	0.00	0.00	0.00	0.00	0.00	0.00	
2	1670.00	0.00	274.96	1670.00	0.00	0.00	0.00	0.00	0.00	
3	1853.34	5.50	274.96	1853.06	0.76	-8.76	3.00	274.96	8.79	
4	7940.31	5.50	274.96	7912.00	51.17	-590.02	0.00	0.00	592.23	IW2 TGT B

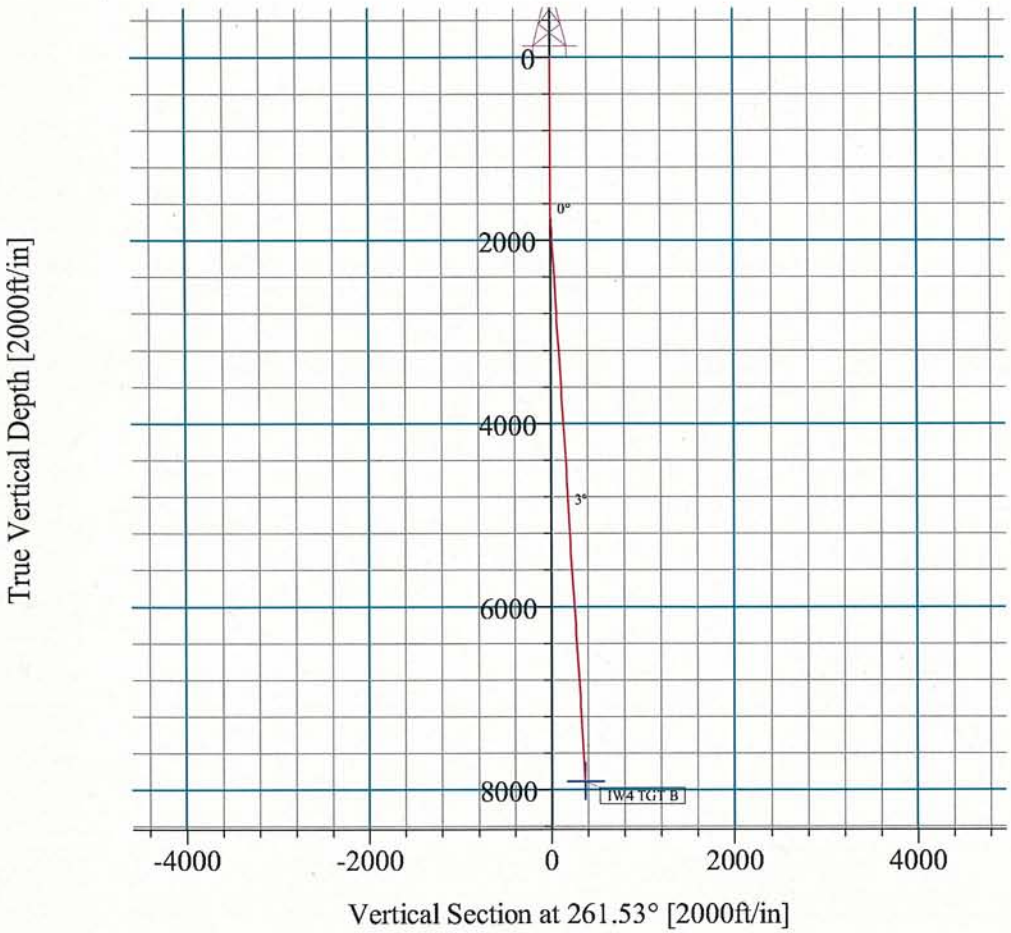
PANOCHE ENERGY, LLC

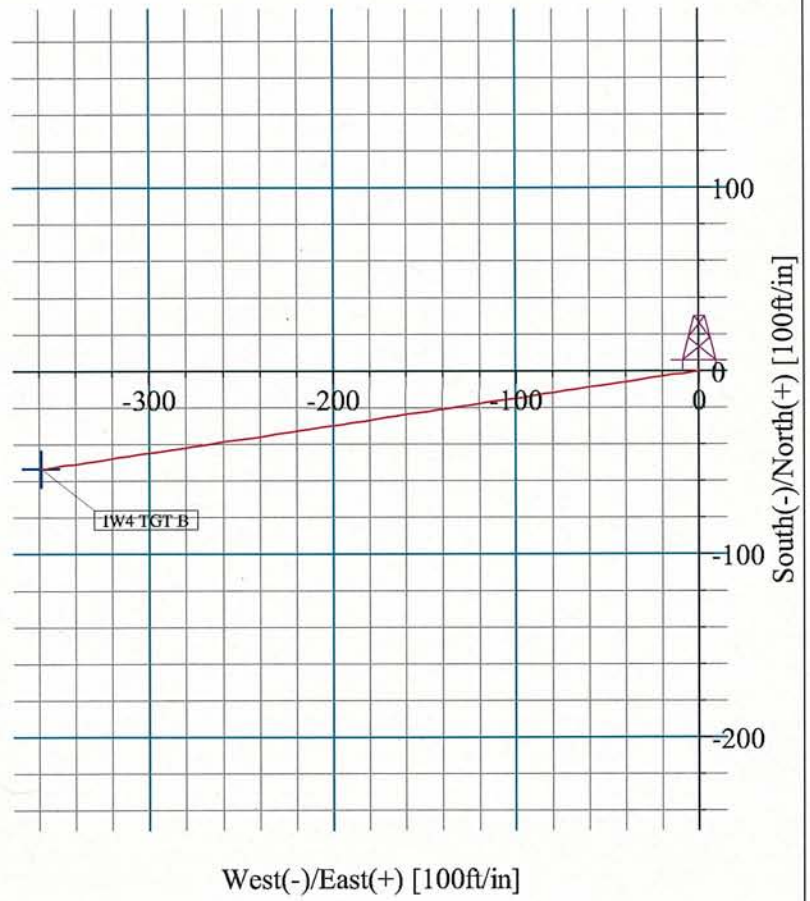
Field: CHENEY RANCH
Site: SECTION 5
Well: IW4
Wellpath: IW4 PLAN B
Plan: Plan B 011208V2



Azimuths to Grid North
True North: 0.94°
Magnetic North: 14.93°

Magnetic Field
Strength: 48906nT
Dip Angle: 60.72°
Date: 1/12/2008
Model: igrf2005





TARGET DETAILS

Name	TVD	+N/-S	+E/-W	Shape
IW4 TGT B	7912.00	-53.44	-358.88	Point

Scientific Drilling
West Coast Operations

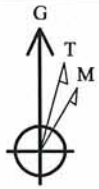
KOP 1670'
DOG LEG RATE 2°/100'
TAR. POINT

SECTION DETAILS

Sec	MD	Inc	Azi	TVD	+N/-S	+E/-W	DLeg	TFace	VSec	Target
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
2	1670.00	0.00	0.00	1670.00	0.00	0.00	0.00	0.00	0.00	
3	1838.61	3.37	261.53	1838.51	-0.73	-4.91	2.00	261.53	4.96	
4	7922.63	3.37	261.53	7912.00	-53.44	-358.88	0.00	0.00	362.84	IW4 TGT B

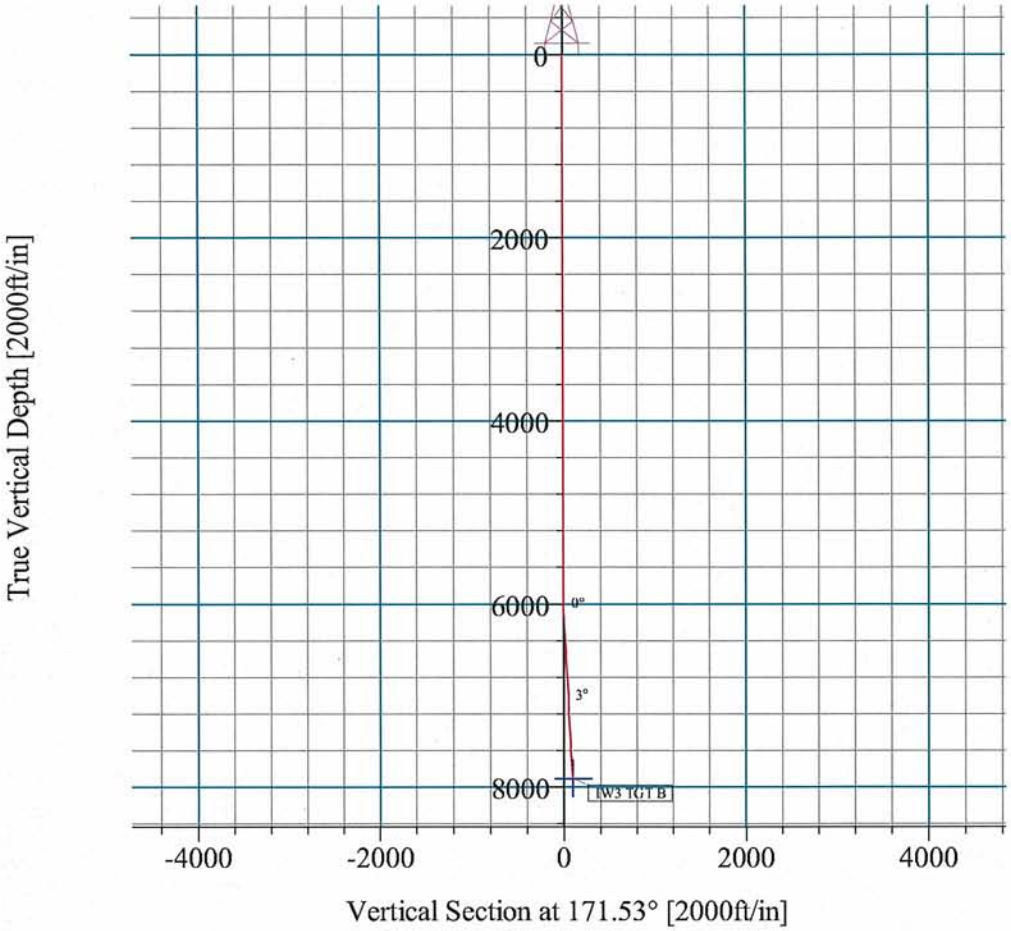
PANOCHE ENERGY, LLC

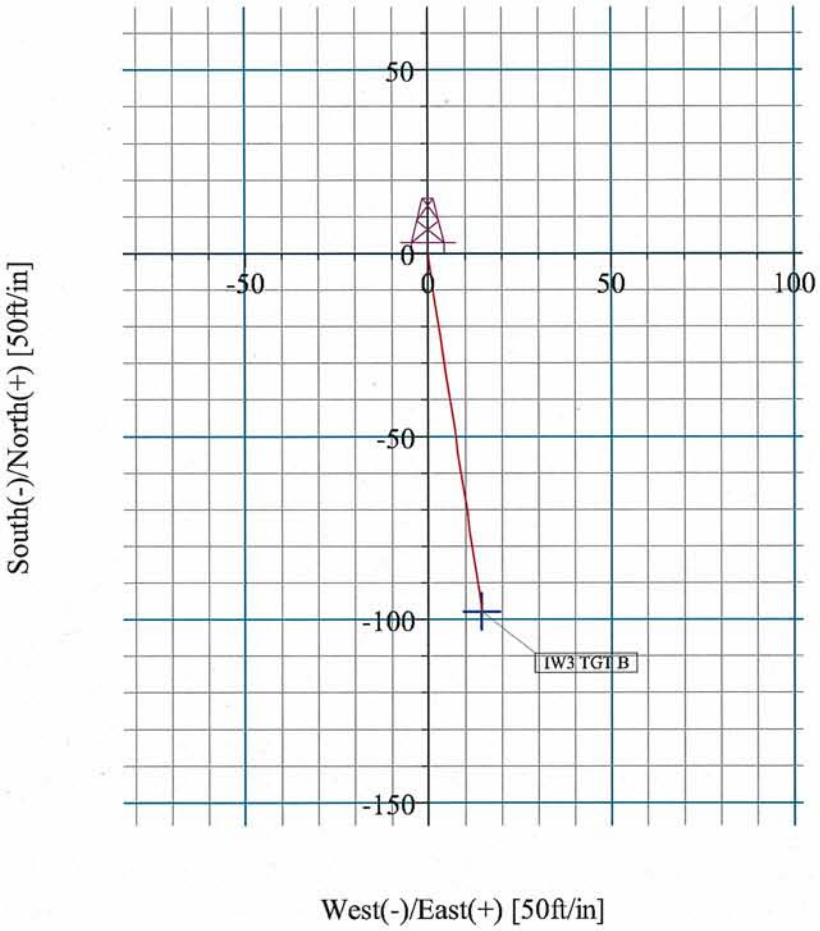
Field: CHENEY RANCH
Site: SECTION 5
Well: IW3
Wellpath: IW3 PLAN B
Plan: Plan B 011208V1



Azimuths to Grid North
True North: 0.94°
Magnetic North: 14.93°

Magnetic Field
Strength: 48906nT
Dip Angle: 60.72°
Date: 1/12/2008
Model: igrf2005





TARGET DETAILS

Name	TVD	+N/-S	+E/-W	Shape
IW3 TGT B	7912.00	-97.70	14.55	Point

Scientific Drilling
West Coast Operations

KOP 6000'
DOG LEG RATE 2°/100'
TAR. POINT

SECTION DETAILS

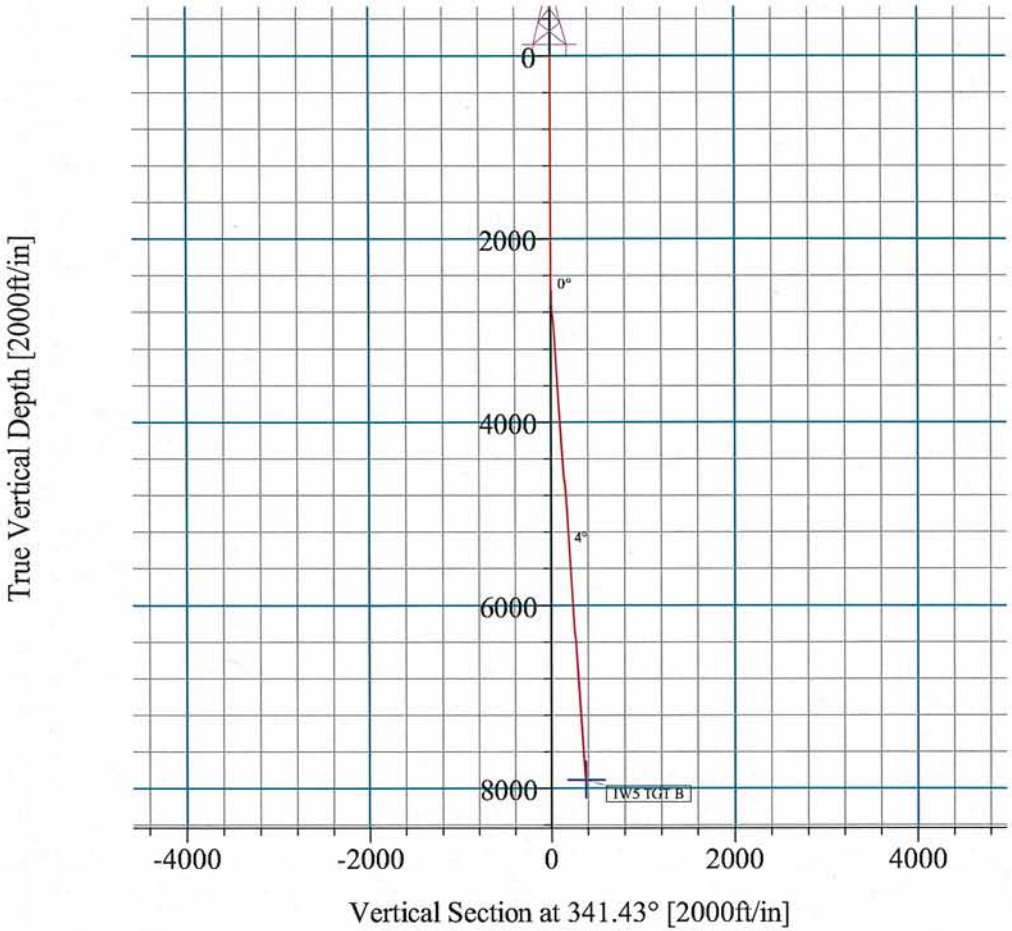
Sec	MD	Inc	Azi	TVD	+N/-S	+E/-W	DLeg	TFace	VSec	Target
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
2	6000.00	0.00	0.00	6000.00	0.00	0.00	0.00	0.00	0.00	
3	6154.07	3.08	171.53	6153.99	-4.10	0.61	2.00	171.53	4.14	
4	7914.62	3.08	171.53	7912.00	-97.70	14.55	0.00	0.00	98.78	IW3 TGT B

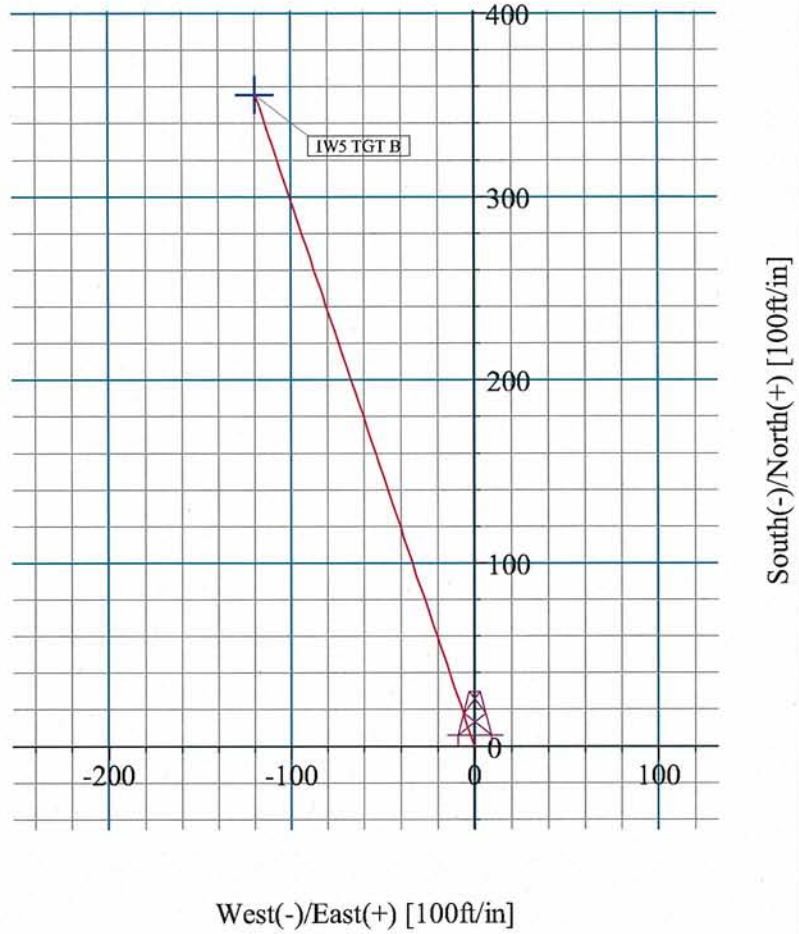
PANOCHE ENERGY, LLC

Field: CHENEY RANCH
Site: SECTION 5
Well: IW5
Wellpath: IW5 PLAN B
Plan: Plan B 011208V2

Azimuths to Grid North
True North: 0.95°
Magnetic North: 14.93°

Magnetic Field
Strength: 48906nT
Dip Angle: 60.72°
Date: 1/12/2008
Model: igrf2005





TARGET DETAILS

Name	TVD	+N/-S	+E/-W	Shape
IW5 TGT B	7912.00	355.50	-119.42	Point

Scientific Drilling
West Coast Operations

KOP 1670'
DOG LEG RATE 2°/100'
TAR. POINT

SECTION DETAILS

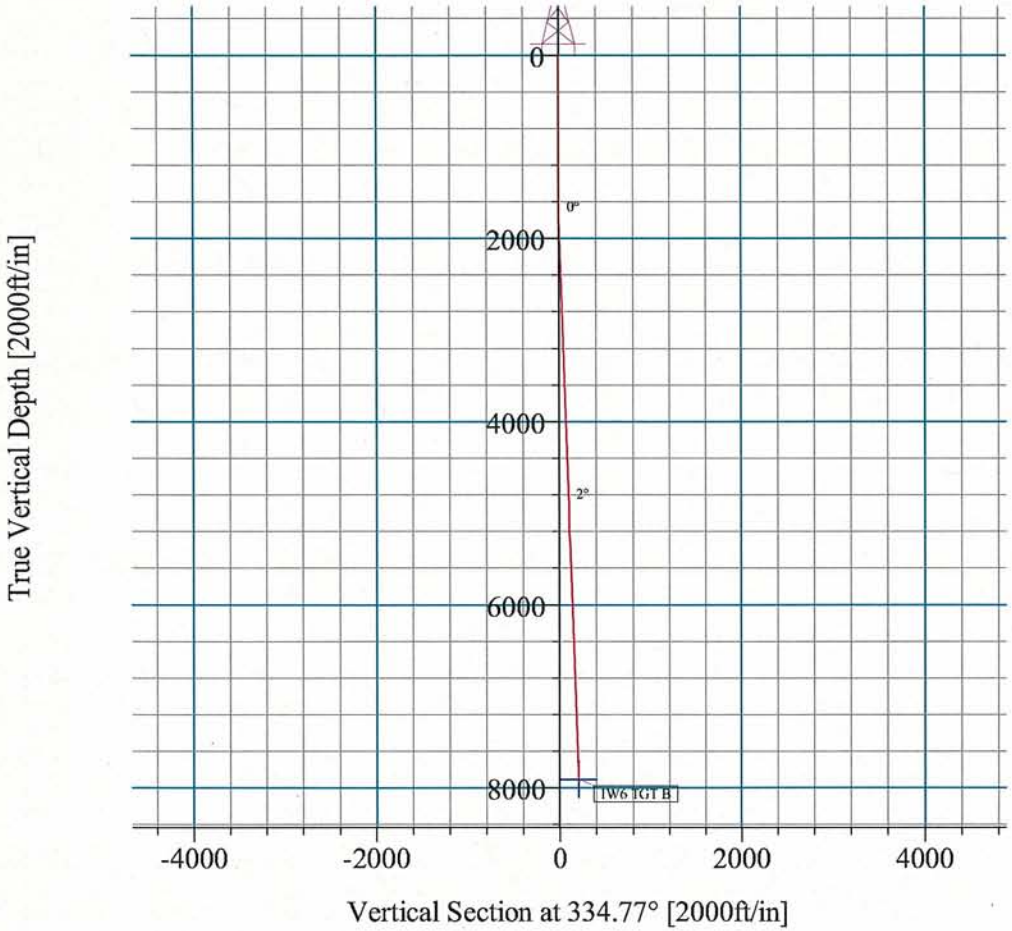
Sec	MD	Inc	Azi	TVD	+N/-S	+E/-W	DLeg	TFace	VSec	Target
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
2	2500.00	0.00	0.00	2500.00	0.00	0.00	0.00	0.00	0.00	
3	2701.95	4.04	341.43	2701.79	6.75	-2.27	2.00	341.43	7.12	
4	7925.14	4.04	341.43	7912.00	355.50	-119.42	0.00	0.00	375.02	IW5 TGT B

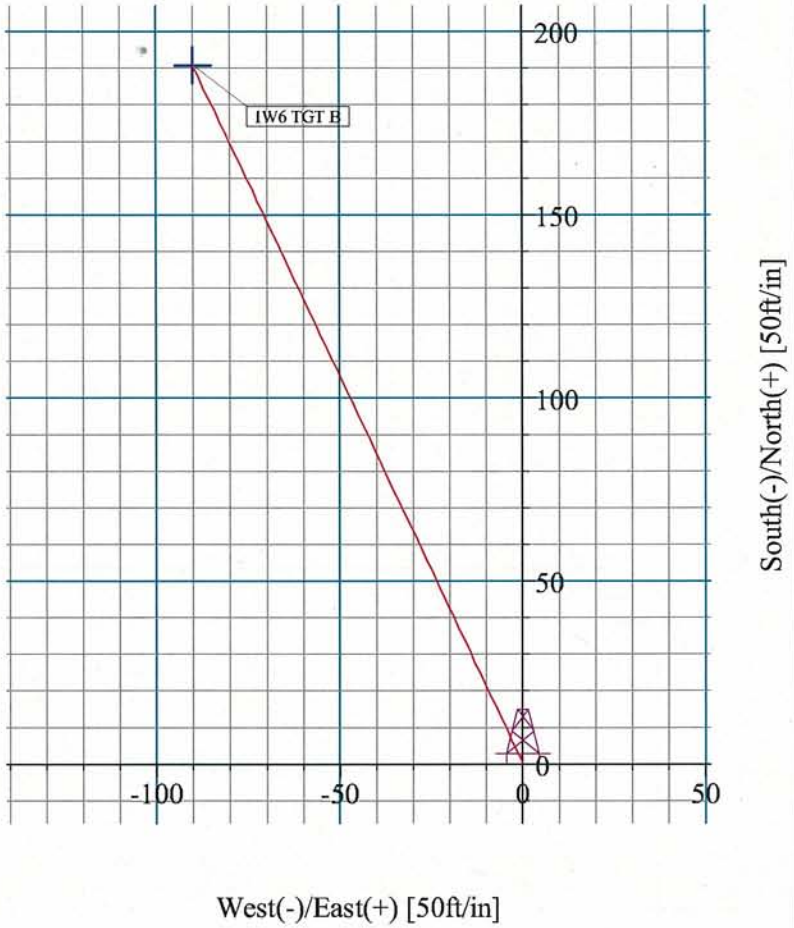
PANOCHE ENERGY, LLC

Field: CHENEY RANCH
Site: SECTION 5
Well: IW6
Wellpath: IW6 PLAN B
Plan: Plan B 011208V2

Azimuths to Grid North
True North: 0.95°
Magnetic North: 14.93°

Magnetic Field
Strength: 48906nT
Dip Angle: 60.72°
Date: 1/12/2008
Model: igrf2005





TARGET DETAILS

Name	TVD	+N/-S	+E/-W	Shape
IW6 TGT B	7912.00	190.88	-89.96	Point

Scientific Drilling
West Coast Operations

KOP 1670'
DOG LEG RATE 2°/100'
TAR. POINT

SECTION DETAILS

Sec	MD	Inc	Azi	TVD	+N/-S	+E/-W	DLeg	TFace	VSec	Target
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
2	1670.00	0.00	0.00	1670.00	0.00	0.00	0.00	0.00	0.00	
3	1734.88	1.95	334.77	1734.86	1.00	-0.47	3.00	334.77	1.10	
4	7915.58	1.95	334.77	7912.00	190.88	-89.96	0.00	0.00	211.02	IW6 TGT B

APPENDIX C – EPA REPORTING FORMS
(The website for downloading these forms is at:
http://www.epa.gov/safewater/uic/7520s.html)

Form 7520-7:	Application to Transfer Permit
Form 7520-9:	Completion of Construction
Form 7520-10:	Well Completion Report
Form 7520-11:	Annual Well Monitoring Report
Form 7520-12:	Well Rework Record
Form 7520-14:	Plugging and Abandonment Plan

APPENDIX D – TEMPERATURE LOGGING REQUIREMENTS
U.S.E.P.A. REGION IX

A Temperature "Decay" Log (two separate temperature logging passes) must satisfy the following criteria to be considered a valid Mechanical Integrity Test ("MIT") as specified by 40 CFR §146.8(c)(1). Variances to these requirements are expected for certain circumstances, but they must be approved prior to running the log. As a general rule, the well shall inject for approximately six (6) months prior to running a temperature decay progression sequence of logs.

1. With the printed log, also provide raw data for both logging runs (at least one data reading per foot depth) unless the logging truck is equipped with an analog panel as the processing device.
2. The heading on the log must be complete and include all the pertinent information, such as correct well name, location, elevations, etc.
3. The total shut-in times must be clearly shown in the heading. Minimum shut-in time for active injectors is 12 hours for running the initial temperature log, followed by a second log, a minimum of 4 hours later. These two log runs will be superimposed on the same track for final presentation.
4. The logging speed must be kept between 20 and 50 ft. per minute (30 ft/min optimum) for both logs. The temperature sensor should be located as close to the bottom of the tool string as possible (logging downhole).
5. The vertical depth scale of the log should be 1 or 2 in. per 100 ft. to match lithology logs (see 7(b)). The horizontal temperature scale should be no more than one Fahrenheit degree per inch spacing.
6. The right hand tracks must contain the "absolute" temperature and the "differential" temperature curves with both log runs identified and clearly superimposed for comparison and interpretation purposes.
7. The left hand tracks must contain (unless impractical, but EPA must pre-approve any deviations):
   (a) a collar locator log,
   (b) a lithology log:
      i. an historic Gamma Ray that is "readable", i.e. one that demonstrates lithologic changes without either excessive activity by the needle or severely dampened responses; or
      ii. a copy of an original SP curve from either the subject well or from a representative, nearby well.
   (c) A clear identification on the log showing the base of the lowermost Underground Source of Drinking Water ("USDW"). A USDW is basically a formation that contains less than 10,000 ppm Total Dissolved Solids ("TDS") and is further defined in 40 CFR §144.3.

APPENDIX E - REGION 9 UIC PRESSURE FALLOFF TEST REQUIREMENTS

EPA Region 9
UIC PRESSURE FALLOFF
REQUIREMENTS

Condensed version of the
EPA Region 6
UIC PRESSURE FALLOFF
TESTING GUIDELINE
Third Revision

August 8, 2002

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REQUIREMENTS

UIC PRESSURE FALLOFF TESTING GUIDELINE
Third Revision
August 8, 2002

1.0 Background

Region 9 has adopted the Region 6 UIC Pressure Falloff Testing Guideline requirements for monitoring Class 1 Non Hazardous waste disposal wells. Under 40 CFR 146.13(d)(1), operators are required annually to monitor the pressure buildup in the injection zone, including at a minimum, a shut down of the well for a time sufficient to conduct a valid observation of the pressure falloff curve.

All of the following parameters (Test, Period, Analysis) are critical for evaluation of technical adequacy of UIC permits:

A falloff **test** is a pressure transient test that consists of shutting in an injection well and measuring the pressure falloff. The falloff **period** is a replay of the injection preceding it; consequently, it is impacted by the magnitude, length, and rate fluctuations of the injection period. Falloff testing **analysis** provides transmissibility, skin factor, and well flowing and static pressures.

2.0 Purpose of Guideline

This guideline has been adopted by the Region 9 office of the Evironmental Protection Agency (EPA) to assist operators in **planning and conducting** the falloff test and preparing the **annual monitoring report**.

Falloff tests provide reservoir pressure data and characterize both the injection interval reservoir and the completion condition of the injection well. Both the reservoir parameters and pressure data are necessary for UIC permit demonstrations. Additionally, a valid falloff test is a monitoring requirement under 40 CFR Part 146 for all Class I injection wells.

The ultimate responsibility of conducting a valid falloff test is the task of the operator. Operators should QA/QC the pressure data and test results to confirm that the results "make sense" prior to submission of the report to the EPA for review.

3.0 Timing of Falloff Tests and Report Submission

Falloff **tests** must be conducted annually. The time **interval** for each test should not be less than 9 months or greater than 15 months from the previous test. This will ensure that the tests will be performed at relatively even intervals.

The falloff testing **report** should be submitted no later than 60 days following the test. Failure to submit a falloff test report will be considered a violation and may result in an enforcement action. Any exceptions should be approved by EPA prior to conducting the test.

4.0 Falloff Test Report Requirements

In general, the **report** to EPA should provide:

(1) general information and an overview of the falloff test,
(2) an analysis of the pressure data obtained during the test,
(3) a summary of the test results, and
(4) a comparison of those results with previously used parameters.

Some of the following operator and well data will not change so once acquired, it can be copied and submitted with each annual report. The **falloff test report** should include the following information:

1. **Company name and address**
2. **Test well name and location**
3. The name and phone number of **the facility contact person**. The contractor contact may be included if approved by the facility in addition to a facility contact person.
4. **A photocopy of an openhole log** (SP or Gamma Ray) through the injection interval illustrating the type of formation and thickness of the injection interval. The entire log is not necessary.
5. **Well schematic** showing the current wellbore configuration and completion information:
   - X Wellbore radius
   - X Completed interval depths
   - X Type of completion (perforated, screen and gravel packed, openhole)
6. **Depth of fill depth and date tagged.**
7. **Offset well information:**
   - X Distance between the test well and offset well(s) completed in the same interval or involved in an interference test
   - X Simple illustration of locations of the injection and offset wells
8. **Chronological listing of daily testing activities.**
9. **Electronic submission of the raw data (time, pressure, and temperature)** from all pressure gauges utilized on CD-ROM. A READ.ME file or the disk label should list all files included and any necessary explanations of the data. A separate file containing any

edited data used in the analysis can be submitted as an additional file.

10. **Tabular summary of the injection rate or rates preceding the falloff test.** At a minimum, rate information for 48 hours prior to the falloff or for a time equal to twice the time of the falloff test is recommended. If the rates varied and the rate information is greater than 10 entries, the rate data should be submitted electronically as well as a hard copy of the rates for the report. Including a rate vs time plot is also a good way to illustrate the magnitude and number of rate changes prior to the falloff test.
11. **Rate information from any offset wells completed in the same interval.** At a minimum, the injection rate data for the 48 hours preceding the falloff test should be included in a tabular and electronic format. Adding a rate vs time plot is also helpful to illustrate the rate changes.
12. **Hard copy of the time and pressure data** analyzed in the report.
13. **Pressure gauge information:** (See Appendix, page A-1 for more information on pressure gauges)
    - X List all the gauges utilized to test the well
    - X Depth of each gauge
    - X Manufacturer and type of gauge. Include the full range of the gauge.
    - X Resolution and accuracy of the gauge as a % of full range.
    - X Calibration certificate and manufacturer's recommended frequency of calibration
14. **General test information:**
    - X Date of the test
    - X Time synchronization: A specific time and date should be synchronized to an equivalent time in each pressure file submitted. Time synchronization should also be provided for the rate(s) of the test well <u>and any offset wells</u>.
    - X Location of the shut-in valve (e.g., note if at the wellhead or number of feet from the wellhead)
15. **Reservoir parameters (determination):**
    - X Formation fluid viscosity, μ_f cp (direct measurement or correlation)
    - X Porosity, φ fraction (well log correlation or core data)
    - X Total compressibility, c_t psi^{-1} (correlations, core measurement, or well test)
    - X Formation volume factor, rvb/stb (correlations, usually assumed 1 for water)
    - X Initial formation reservoir pressure - See Appendix, page A-1
    - X Date reservoir pressure was last stabilized (injection history)
    - X Justified interval thickness, h ft - See Appendix, page A-15
16. **Waste plume:**
    - X Cumulative injection volume into the completed interval
    - X Calculated radial distance to the waste front, r_{waste} ft
    - X Average historical waste fluid viscosity, if used in the analysis, μ_{waste} cp

17. **Injection period:**
    - X Time of injection period
    - X Type of test fluid
    - X Type of pump used for the test (e.g., plant or pump truck)
    - X Type of rate meter used
    - X Final injection pressure and temperature
18. **Falloff period:**
    - X Total shut-in time, expressed in real time and Δt, elapsed time
    - X Final shut-in pressure and temperature
    - X Time well went on vacuum, if applicable
19. **Pressure gradient:**
    - X Gradient stops - for depth correction
20. **Calculated test data:** include all equations used and the parameter values assigned for each variable within the report
    - X Radius of investigation, r_i ft
    - X Slope or slopes from the semilog plot
    - X Transmissibility, kh/μ md-ft/cp
    - X Permeability (range based on values of h)
    - X Calculation of skin, s
    - X Calculation of skin pressure drop, ΔP_{skin}
    - X Discussion and justification of any reservoir or outer boundary models used to simulate the test
    - X Explanation for any pressure or temperature anomaly if observed
21. **Graphs:**
    - X Cartesian plot: pressure and temperature vs. time
    - X Log-log diagnostic plot: pressure and semilog derivative curves. Radial flow regime should be identified on the plot
    - X Semilog and expanded semilog plots: radial flow regime indicated and the semilog straight line drawn
    - X Injection rate(s) vs time: test well and offset wells (not a circular or strip chart)
22. **A copy of the latest radioactive tracer run** and a brief discussion of the results.

5.0 Planning

The **radial flow portion** of the test is the basis for all pressure transient calculations. Therefore the injectivity and falloff portions of the test should be designed not only to reach radial flow, but to sustain a time frame sufficient for analysis of the radial flow period.

General Operational Concerns

X Adequate storage for the waste should be ensured for the duration of the test

X Offset wells completed in the same formation as the test well should be shut-in, or at a minimum, provisions should be made to maintain a constant injection rate prior to and during the test

X Install a crown valve on the well prior to starting the test so the well does not have to be shut-in to install a pressure gauge

X The location of the shut-in valve on the well should be at or near the wellhead to minimize the wellbore storage period

X The condition of the well, junk in the hole, wellbore fill or the degree of wellbore damage (as measured by skin) may impact the length of time the well must be shut-in for a valid falloff test. This is especially critical for wells completed in relatively low transmissibility reservoirs or wells that have large skin factors.

X Cleaning out the well and acidizing may reduce the wellbore storage period and therefore the shut-in time of the well

X Accurate recordkeeping of injection rates is critical including a mechanism to synchronize times reported for injection rate and pressure data. The elapsed time format usually reported for pressure data does not allow an easy synchronization with real time rate information. Time synchronization of the data is especially critical when the analysis includes the consideration of injection from more than one well.

X Any unorthodox testing procedure, or any testing of a well with known or anticipated problems, should be discussed with EPA staff prior to performing the test.

X If more than one well is completed into the same reservoir, operators are encouraged to send at least two pulses to the test well by way of rate changes in the offset well following the falloff test. These pulses will demonstrate communication between the wells and, if maintained for sufficient duration, they can be **analyzed as an interference test** to obtain interwell reservoir parameters.

Site Specific Pretest Planning

1. Determine the time needed to reach radial flow during the injectivity and falloff portions of the test:
   - X Review previous welltests, if available
   - X Simulate the test using measured or estimated reservoir and well completion parameters
   - X Calculate the time to the beginning of radial flow using the empirically-based equations provided in the Appendix. The equations are different for the injectivity and falloff portions of the test with the skin factor influencing the falloff more than the injection period. (See Appendix, page A-4 for equations)
   - X Allow adequate time beyond the beginning of radial flow to observe radial flow so that a well developed semilog straight line occurs. A good rule of thumb is 3 to 5 times the time to reach radial flow to provide adequate radial flow data for analysis.

2. Adequate and consistent injection fluid should be available so that the injection rate into the test well can be held constant prior to the falloff. This rate should be high enough to

produce a measurable falloff at the test well given the resolution of the pressure gauge selected. The viscosity of the fluid should be consistent. Any mobility issues (k/μ) should be identified and addressed in the analysis if necessary.

3. Bottomhole pressure measurements are required. (See Appendix, page A-2 for additional information concerning pressure gauge selection.)

4. Use two pressure gauges during the test with one gauge serving as a backup, or for verification in cases of questionable data quality. The two gauges do not need to be the same type. (See Appendix, page A-1 for additional information concerning pressure gauges.)

6.0 Conducting the Falloff Test

1. Tag and record the depth to any fill in the test well

2. Simplify the pressure transients in the reservoir
   - X Maintain a constant injection rate in the test well prior to shut-in. This injection rate should be high enough and maintained for a sufficient duration to produce a measurable pressure transient that will result in a valid falloff test.
   - X Offset wells should be shut-in prior to and during the test. If shut-in is not feasible, a constant injection rate should be recorded and maintained during the test and then accounted for in the analysis.
   - X Do not shut-in two wells simultaneously or change the rate in an offset well during the test.

3. The test well should be shut-in <u>at the wellhead</u> in order to minimize wellbore storage and afterflow. (See Appendix, page A-3 for additional information.)

4. Maintain accurate rate records for the test well and any offset wells completed in the same injection interval.

5. Measure and record the viscosity of the injectate periodically during the injectivity portion of the test to confirm the consistency of the test fluid.

7.0 Evaluation of the Falloff Test

1. Prepare a **Cartesian plot** of the pressure and temperature versus real time or elapsed time.
   - X Confirm pressure stabilization prior to shut-in of the test well
   - X Look for anomalous data, pressure drop at the end of the test, determine if pressure drop is within the gauge resolution

2. Prepare a **log-log diagnostic plot** of the pressure and semilog derivative. Identify the

flow regimes present in the welltest. (See Appendix, page A-6 for additional information.)

- X Use the appropriate time function depending on the length of the injection period and variation in the injection rate preceding the falloff (See Appendix, page A-10 for details on time functions.)
- X **Mark the various flow regimes** - particularly the radial flow period
- X Include the derivative of other plots, if appropriate (e.g., square root of time for linear flow)
- X If there is no radial flow period, attempt to type curve match the data

3. Prepare a **semilog plot**.
   - X Use the appropriate time function depending on the length of injection period and injection rate preceding the falloff
   - X Draw the semilog straight line through the radial flow portion of the plot and obtain the slope of the line
   - X Calculate the transmissibility, kh/μ
   - X Calculate the skin factor, s, and skin pressure drop, ΔP_{skin}
   - X Calculate the radius of investigation, r_i

4. Explain any anomalous results.

8.0 Technical References

1. SPE Textbook Series No. 1, "Well Testing," 1982, W. John Lee
2. SPE Monograph 5, "Advances in Well Test Analysis," 1977, Robert Earlougher, Jr.
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8. "Well Testing: Interpretation Methods," Bourdarot, 1996
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12. EPA Region 6 Falloff Guidelines
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19. "Three Key Elements Necessary for Successful Testing," Oil and Gas Journal, Ehlig-Economides, Hegeman, Clark, July 25, 1994
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22. "Fundamentals of Type Curve Analysis," Hart's Petroleum Engineer International, Spivey, and Lee, September 1997
23. "Identifying Flow Regimes In Pressure Transient Tests," Hart's Petroleum Engineer International, Spivey and Lee, October 1997
24. "Selecting a Reservoir Model For Well Test Interpretation," Hart's Petroleum Engineer International, Spivey, Ayers, Pursell,and Lee, December 1997
27. "Use of Pressure Derivative in Well-Test Interpretation," SPE Paper 12777, SPE Formation Evaluation Journal, Bourdet, Ayoub, and Pirard, June 1989
28. "A New Set of Type Curves Simplifies Well Test Analysis," World Oil, Bourdet, Whittle, Douglas, and Pirard, May 1983

APPENDIX

Pressure Gauge Usage and Selection

Usage

X EPA recommends that two gauges be used during the test with one gauge serving as a backup.

X **Downhole pressure measurements** are less noisy and are required.

X A bottomhole surface readout gauge (SRO) allows tracking of pressures in real time. Analysis of this data can be performed in the field to confirm that the well has reached radial flow prior to ending the test.

X The derivative function plotted on the log-log plot amplifies noise in the data, so the use of a good pressure recording device is critical for application of this curve.

X Mechanical gauges should be **calibrated** before and after each test using a dead weight tester.

X Electronic gauges should also be **calibrated** according to the manufacturer's recommendations. The manufacturer's recommended frequency of calibration, and a copy of the gauge calibration certificate should be provided with the falloff testing report demonstrating this practice has been followed.

Selection

X The pressures must remain within the range of the pressure gauge. The larger percent of the gauge range utilized in the test, the better. Typical pressure gauge limits are 2000, 5000, and 10000 psi. Note that gauge accuracy and resolution are typically a function of percent of the full gauge range.

X Electronic downhole gauges generally offer much better resolution and sensitivity than a mechanical gauge but cost more. Additionally, the electronic gauge can generally run for a longer period of time, be programmed to measure pressure more frequently at various intervals for improved data density, and store data in digital form.

X Resolution of the pressure gauge must be sufficient to measure small pressure changes at the end of the test.

Test Design

General Operational Considerations

X The injection period controls what is seen on the falloff since the falloff is replay of the injection period. Therefore, the injection period must reach radial flow prior to shut-in of the well in order for the falloff test to reach radial flow

X Ideally to determine the optimal lengths of the injection and falloff periods, the test should be simulated using measured or estimated reservoir parameters. Alternatively, injection and falloff period lengths can be estimated from empirical equations using assumed reservoir and well parameters.

X The injection rate dictates the pressure buildup at the injection well. The pressure buildup from injection must be sufficient so that the pressure change during radial flow, usually occurring toward the end of the test, is large enough to measure with the pressure gauge selected.

X Waste storage and other operational issues require preplanning and need to be addressed prior to the test date. If brine must be brought in for the injection portion of the test, operators should insure that the fluid injected has a consistent viscosity and that there is adequate fluid available to obtain a valid falloff test. The use of the wastestream as the injection fluid affords several distinct advantages:

1. Brine does not have to be purchased or stored prior to use.
2. Onsite waste storage tanks may be used.
3. Plant wastestreams are generally consistent, i.e., no viscosity variations

X Rate changes cause pressure transients in the reservoir. **Constant rate injection in the test well and any offset wells completed in the same reservoir are critical to simplify the pressure transients in the reservoir.** Any significant injection rate fluctuations at the test well or offsets must be recorded and accounted for in the analysis using superposition.

X Unless an injectivity test is to be conducted, shutting in the well for an extend period of time prior to conducting the falloff test reduces the pressure buildup in the reservoir and is not recommended.

X Prior to conducting a test, a crown valve should be installed on the wellhead to allow the pressure gauge to be installed and lowered into the well without any interruption of the injection rate.

X The wellbore schematic should be reviewed for possible obstructions located in the well that may prevent the use or affect the setting depth of a downhole pressure gauge. The fill depth in the well should also be reported. The fill depth may not only impact the depth of the gauge, but usually prolongs the wellbore storage period and depending on the type of fill, may limit the interval thickness by isolating some of the injection intervals. A wellbore cleanout or stimulation may be needed prior to conducting the test for the test to reach radial flow and obtain valid results.

X The location of the shut-in valve can impact the duration of the wellbore storage period. The shut-in valve should be located near the wellhead. Afterflow into the wellbore prolongs the wellbore storage period.

X The area geology should be reviewed prior to conducting the test to determine the thickness and type of formation being tested along with any geological features such as natural fractures, a fault, or a pinchout that should be anticipated to impact the test.

Wellbore and Reservoir Data Needed to Simulate or Analyze the Falloff Test

X Wellbore radius, r_w - from wellbore schematic

X Net thickness, h - See Appendix, page A-15
X Porosity, φ - log or core data
X Viscosity of formation fluid, μ_f - direct measurement or correlations
X Viscosity of waste, μ_{waste} - direct measurement or correlations
X Total system compressibility, c_t - correlations, core measurement, or well test
X Permeability, k - previous welltests or core data
X Specific gravity of injection fluid, s.g. - direct measurement
X Injection rate, q - direct measurement

Design Calculations

When simulation software is unavailable the test periods can be estimated from empirical equations. The following are set of steps to calculate the time to reach radial flow from empirically-derived equations:

1. Estimate the wellbore storage coefficient, C (bbl/psi). There are two equations to calculate the wellbore storage coefficient depending on if the well remains fluid filled (positive surface pressure) or if the well goes on a vacuum (falling fluid level in the well):
   a. Well remains fluid filled:

$$C = V_w \cdot c_{waste}$$

where, V_w is the total wellbore volume, bbls
c_{waste} is the compressibility of the injectate, psi^{-1}

   b. Well goes on a vacuum:

$$C = \frac{V_u}{\frac{\rho \cdot g}{144 \cdot g_c}}$$

where, V_u is the wellbore volume per unit length, bbls/ft
ρ is the injectate density, psi/ft
g and g_c are gravitational constants

2. Calculate the time to reach radial flow for both the injection and falloff periods. Two different empirically-derived equations are used to calculate the time to reach radial flow, $t_{radial\ flow}$, for the injectivity and falloff periods:
   a. Injectivity period:

$$t_{radial\,flow} > \frac{(200000 + 12000s) \cdot C}{\frac{k \cdot h}{\mu}} \quad hours$$

   b. Falloff period:

$$t_{radial\,flow} > \frac{170000 \cdot C \cdot e^{0.14 \cdot s}}{\frac{k \cdot h}{\mu}} \quad hours$$

The wellbore storage coefficient is assumed to be the same for both the injectivity and falloff periods. The skin factor, s, influences the falloff more than the injection period. Use these equations with caution, as they tend to fall apart for a well with a large

permeability or a high skin factor. Also remember, the welltest should not only reach radial flow, but also sustain radial flow for a timeframe sufficient for analysis of the radial flow period. As a rule of thumb, a timeframe sufficient for analysis is 3 to 5 times the time needed to reach radial flow.

3. As an alternative to steps 1 and 2, to look a specific distance "L" into the reservoir and possibly confirm the absence or existence of a boundary, the following equation can be used to estimate the time to reach that distance:

$$t_{boundary} = \frac{948 \cdot \phi \cdot \mu \cdot c_t \cdot L_{boundary}}{k} \quad hours$$

where, $L_{boundary}$ = feet to boundary
$t_{boundary}$ = time to boundary, hrs

Again, this is the time to reach a distance "L" in the reservoir. Additional test time is required to observe a fully developed boundary past the time needed to just reach the boundary. As a rule of thumb, to see a fully developed boundary on a log-log plot, allow at least 5 times the time to reach it. Additionally, for a boundary to show up on the falloff, it must first be encountered during the injection period.

4. Calculate the expected slope of the semilog plot during radial flow to see if gauge resolution will be adequate using the following equation:

$$m_{semilog} = \frac{162.6 \cdot q \cdot B}{\frac{k \cdot h}{\mu}}$$

where, q = the injection rate preceding the falloff test, bpd
B = formation volume factor for water, rvb/stb (usually assumed to be 1)

Considerations for Offset Wells Completed in the Same Interval

Rate fluctuations in offset wells create additional pressure transients in the reservoir and complicate the analysis. Always try to simplify the pressure transients in the reservoir. Do not simultaneously shut-in an offset well and the test well. The following items are key considerations in dealing with the impact of offset wells on a falloff test:

X Shut-in all offset wells prior to the test
X If shutting in offset wells is not feasible, maintain a constant injection rate prior to and during the test
X Obtain accurate injection records of offset injection prior to and during the test
X At least one of the real time points corresponding to an injection rate in an offset well should be synchronized to a specific time relating to the test well
X **Following the falloff test in the test well, send at least two pulses from the offset well to the test well by fluctuating the rate in the offset well.** The pressure pulses can confirm communication between the wells and can be simulated in the analysis if observed at the test well. The pulses can also be analyzed as an interference test using an Ei type curve.

X If time permits, conduct an interference test to allow evaluation of the reservoir without the wellbore effects observed during a falloff test.

Falloff Test Analysis

In performing a falloff test analysis, a series of plots and calculations should be prepared to QA/QC the test, identify flow regimes, and determine well completion and reservoir parameters. Individual plots, flow regime signatures, and calculations are discussed in the following sections.

Cartesian Plot

X The pressure data prior to shut-in of the well should be reviewed on a Cartesian plot to confirm pressure stabilization prior to the test. A well that has reached radial flow during the injectivity portion of the test should have a consistent injection pressure.

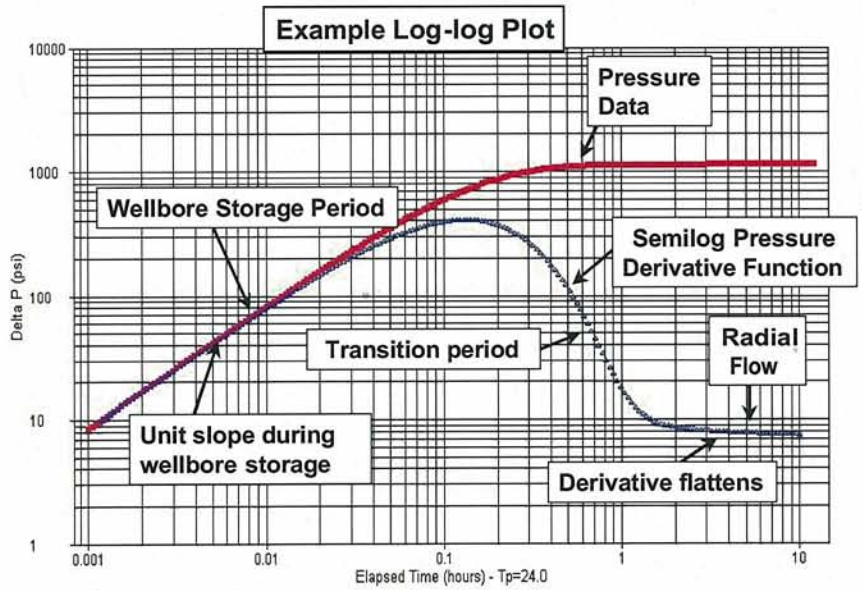
X A Cartesian plot of the pressure and temperature versus real time or elapsed time should be the first plot made from the falloff test data. Late time pressure data should be expanded to determine the pressure drop occurring during this portion of the test. The pressure changes should be compared to the pressure gauges used to confirm adequate gauge resolution existed throughout the test. If the gauge resolution limit was reached, this timeframe should be identified to determine if radial flow was reached prior to reaching the resolution of the pressure gauge. Pressure data obtained after reaching the resolution of the gauge should be treated as suspect and may need to be discounted in the analysis.

X **Falloff tests conducted in highly transmissive reservoirs** may be more sensitive to the temperature compensation mechanism of the gauge because the pressure buildup response evaluated is smaller. Region 6 has observed cases in which large temperature anomalies were not properly compensated for by the pressure gauge, resulting in erroneous pressure data and an incorrect analysis. For this reason, the Cartesian plot of the temperature data should be reviewed. **Any temperature anomalies should be noted to determine if they correspond to pressure anomalies.**

X Include the injection rate(s) of the test well 48 hours prior to shut-in on the Cartesian plot to illustrate the consistency of the injection rate prior to shut-in and to determine the appropriate time function to use on the log-log and semilog plots. (See Appendix, page A10 for time function selection)

Log-log Diagnostic Plot

X Plot the pressure and semilog derivative versus time on a log-log diagnostic plot. Use the appropriate time function based on the rate history of the injection period preceding the falloff. (See Appendix, page A-10 for time function selection) The log-log plot is used to identify the flow regimes present in the welltest. An example log-log plot is shown below:



Identification of Test Flow Regimes

X Flow regimes are mathematical relationships between pressure, rate, and time. Flow regimes provide a visualization of what goes on in the reservoir. Individual flow regimes have characteristic slopes and a sequencing order on the log-log plot.

X Various flow regimes will be present during the falloff test, however, not all flow regimes are observed on every falloff test. The late time responses correlate to distances further from the test well. **The critical flow regime is radial flow from which all analysis calculations are performed.** During radial flow, the pressure responses recorded are representative of the reservoir, not the wellbore.

X The derivative function amplifies reservoir signatures by calculating a running slope of a designated plot. The derivative plot allows a more accurate determination of the radial flow portion of the test, in comparison with the old method of simply proceeding 1½ log cycles from the end of the unit slope line of the pressure curve.

X The derivative is usually based on the semilog plot, but it can also be calculated based on other plots such as a Cartesian plot, a square root of time plot, a quarter root of time plot, and the 1/square root of time plot. Each of these plots are used to identify specific flow regimes. If the flow regime characterized by a specialized plot is present then when the derivative calculated from that plot is displayed on the log-log plot, it will appear as a

"flat spot" during the portion of the falloff corresponding to the flow regime.

X **Typical flow regimes observed on the log-log plot** and their semilog derivative patterns are listed below:

Flow Regime	Semilog Derivative Pattern
Wellbore Storage	Unit slope
Radial Flow	Flat plateau
Linear Flow	Half slope
Bilinear Flow	Quarter slope
Partial Penetration	Negative half slope
Layering	Derivative trough
Dual Porosity	Derivative trough
Boundaries	Upswing followed by plateau
Constant Pressure	Sharp derivative plunge

Characteristics of Individual Test Flow Regimes

X **Wellbore Storage:**

1. Occurs during the early portion of the test and is caused by the well being shut-in at the surface instead of the sandface
2. Measured pressure responses are governed by well conditions and are not representative of reservoir behavior and are characterized by both the pressure and semilog derivative curves overlying a unit slope on the log-log plot
3. Wellbore skin or a low permeability reservoir results in a slower transfer of fluid from the well to the formation, extending the duration of the wellbore storage period
4. A wellbore storage dominated test is unanalyzable

X **Radial Flow:**

1. The pressure responses are from the reservoir, not the wellbore
2. The critical flow regime from which key reservoir parameters and completion conditions calculations are performed
3. Characterized by a flattening of the semilog plot derivative curve on the log-log plot and a straight line on the semilog plot

X **Spherical Flow:**

1. Identifies partial penetration of the injection interval at the wellbore
2. Characterized by the semilog derivative trending along a negative half slope on the log-log plot and a straight line on the 1/square root of time plot
3. The log-log plot derivative of the pressure vs 1/square root of time plot is flat

X **Linear Flow:**

1. May result from flow in a channel, parallel faults, or a highly conductive fracture
2. Characterized by a half slope on both the log-log plot pressure and semilog derivative curves with the derivative curve approximately 1/3 of a log cycle lower than the pressure curve and a straight line on the square root of time plot. 3. The log-log plot derivative of the pressure vs square root of time plot is flat

X **Hydraulically Fractured Well:**

1. Multiple flow regimes present including wellbore storage, fracture linear flow, bilinear flow, pseudo-linear flow, formation linear flow, and pseudo-radial flow
2. Fracture linear flow is usually hidden by wellbore storage
3. Bilinear flow results from simultaneous linear flows in the fracture and from the formation into the fracture, occurs in low conductivity fractures, and is characterized by a quarter slope on both the pressure and semilog derivative curves on the log-log plot and by a straight line on a pressure versus quarter root of time plot
4. Formation linear flow is identified by a half slope on both the pressure and semilog derivative curves on the log-log plot and by a straight line on a pressure versus square root of time plot
5. Psuedo-radial flow is analogous to radial flow in an unfractured well and is characterized by flattening of semilog derivative curve on the log-log plot and a straight line on a semilog pressure plot

X **Naturally Fractured Rock:**

1. The fracture system will be observed first on the falloff test followed by the total system consisting of the fractures and matrix.
2. The falloff analysis is complex. The characteristics of the semilog derivative trough on the log-log plot indicate the level of communication between the fractures and the matrix rock.

X **Layered Reservoir:**

1. Analysis of a layered system is complex because of the different flow regimes, skin factors or boundaries that may be present in each layer.
2. The falloff test objective is to get a total tranmissibility from the **whole reservoir system.**
3. Typically described as commingled (2 intervals with vertical separation) or crossflow (2 intervals with hydraulic vertical communication)

Semilog Plot

X The semilog plot is a plot of the pressure versus the log of time. There are typically four different semilog plots used in pressure transient and falloff testing analysis. After plotting the appropriate semilog plot, a straight line should be drawn through the points located within the equivalent radial flow portion of the plot identified from the log-log

plot.

X Each plot uses a different time function depending on the length and variation of the injection rate preceding the falloff. These plots can give different results for the same test, so it is important that the appropriate plot with the correct time function is used for the analysis. Determination of the appropriate time function is discussed below.

X The slope of the semilog straight line is then used to calculate the reservoir transmissibility - kh/μ, the completion condition of the well via the skin factor - s, and also the radius of investigation - r_i of the test.

Determination of the Appropriate Time Function for the Semilog Plot

The following four different semilog plots are used in pressure transient analysis:

1. Miller Dyes Hutchinson (MDH) Plot
2. Horner Plot
3. Agarwal Equivalent Time Plot
4. Superposition Time Plot

These plots can give different results for the same test. Use of the appropriate plot with the correct time function is critical for the analysis.

X The **MDH plot** is a semilog plot of pressure versus Δt, where Δt is the elapsed shut-in time of the falloff.

1. The MDH plot only applies to wells that reach psuedo-steady state during injection. Psuedo-steady state means the pressure response from the well has encountered all the boundaries around the well.
2. The MDH plot is only applicable to injection wells with a *very* long injection period at a constant rate. This plot is not recommended for use by EPA Region 6.

X The **Horner plot** is a semilog plot of pressure versus $(t_p+\Delta t)/\Delta t$. The Horner plot is only used for a falloff preceded by a single constant rate injection period.

1. The injection time, $t_p=V_p/q$ in hours, where V_p=injection volume since the last pressure equalization and q is the injection rate prior to shut-in for the falloff test. The injection volume is often taken as the cumulative injection since completion.

2. The Horner plot can result in significant analysis error if the injection rate varies prior to the falloff.

X The **Agarwal equivalent time plot** is a semilog plot of the pressure versus Agarwal equivalent time, Δt_e.

1. The Agarwal equivalent time function is similar to the Horner plot, but scales the falloff to make it look like an injectivity test.
2. It is used when the injection period is a short, constant rate compared to the length of the falloff period.
3. The Agarwal equivalent time is defined as: $\Delta t_e=\log(t_p\ \Delta t)/(t_p+\Delta t)$, where t_p is calculated the same as with the Horner plot.

X The **superposition time function** accounts for variable rate conditions preceding the falloff.

1. It is the most rigorous of all the time functions and is usually calculated using welltest software.
2. The use of the superposition time function requires the operator to accurately track the rate history. As a rule of thumb, at a minimum, the rate history for twice the length of the falloff test should be included in the analysis.

The determination of which time function is appropriate for the plotting the welltest on semilog and log-log plots depends on available rate information, injection period length, and software:

1. If there is not a rate history other than a single rate and cumulative injection, use a Horner time function
2. If the injection period is shorter than the falloff test and only a single rate is available, use the Agarwal equivalent time function
3. If you have a variable rate history use superposition when possible. As an alternative to superposition, use Agarwal equivalent time on the log-log plot to identify radial flow. The semilog plot can be plotted in either Horner or Agarwal time if radial flow is observed on the log-log plot.

Parameter Calculations and Considerations

X Transmissibility - The slope of the semilog straight line, m, is used to determine the transmissibility (kh/μ) parameter group from the following equation:

$$\frac{k \cdot h}{\mu} = \frac{162.6 \cdot q \cdot \mathbf{B}}{m}$$

where, q = injection rate, bpd (negative for injection)
B = formation volume factor, rvb/stb (Assumed to be 1 for formation fluid)
m = slope of the semilog straight line through the radial flow portion of the plot in psi/log cycle
k = permeability, md
h = thickness, ft (See Appendix, page A-15)
μ = viscosity, cp

X The viscosity, μ , is usually that of the formation fluid. However, if the waste plume size is massive, the radial flow portion of the test may remain within the waste plume. (See Appendix, page A-14)

1. The waste and formation fluid viscosity values usually are similar, however, if the wastestream has a significant viscosity difference, the size of the waste plume and distance to the radial flow period should be calculated.
2. The mobility, k/μ, differences between the fluids may be observed on the derivative curve.

X The permeability, k, can be obtained from the calculated transmissibility (kh/μ) by substituting the appropriate thickness, h, and viscosity, μ, values.

Skin Factor

X In theory, wellbore skin is treated as an infinitesimally thin sheath surrounding the wellbore, through which a pressure drop occurs due to either damage or stimulation. Industrial injection wells deal with a variety of waste streams that alter the near wellbore environment due to precipitation, fines migration, ion exchange, bacteriological processes, and other mechanisms. It is reasonable to expect that this alteration often exists as a zone surrounding the wellbore and not a skin. Therefore, at least in the case of industrial injection wells, the assumption that skin exists as a thin sheath is not always valid. This does not pose a serious problem to the correct interpretation of falloff testing except in the case of a large zone of alteration, or in the calculation of the flowing bottomhole pressure. Region 6 has seen instances in which large zones of alteration were suspected of being present.

X The skin factor is the measurement of the completion condition of the well. The skin factor is quantified by a positive value indicating a damaged completion and a negative value indicating a stimulated completion.

1. The magnitude of the positive value indicating a damaged completion is dictated by the transmissibility of the formation.
2. A negative value of -4 to -6 generally indicates a hydraulically fractured completion, whereas a negative value of -1 to -3 is typical of an acid stimulation in a sandstone reservoir.
3. The skin factor can be used to calculate the effective wellbore radius, r_{wa} also referred to the apparent wellbore radius. (See Appendix, page A-13)
4. The skin factor can also be used to correct the injection pressure for the effects of wellbore damage to get the actual reservoir pressure from the measured pressure.

X The skin factor is calculated from the following equation:

$$s = 1.1513\left[\frac{P_{1hr} - P_{wf}}{m} - \log\left(\frac{k \cdot t_p}{\left(t_p + 1\right) \cdot \phi \cdot \mu \cdot c_t \cdot r_w^2}\right) + 3.23\right]$$

where, s = skin factor, dimensionless

P_{1hr} = pressure intercept along the semilog straight line at a shut-in time of 1 hour, psi

P_{wf} = measured injection pressure prior to shut-in, psi

μ = appropriate viscosity at reservoir conditions, cp (See Appendix, page A-14)

m = slope of the semilog straight line, psi/cycle

k = permeability, md

φ = porosity, fraction

c_t = total compressibility, psi^{-1}

r_w = wellbore radius, feet

t_p = injection time, hours

Note that the term $t_p/(t_p + \Delta t)$, where Δt=1 hr, appears in the log term. This term is usually assumed to result in a negligible contribution and typically is taken as 1 for large t. However, for relatively short injection periods, as in the case of a drill stem test (DST), this term can be significant.

Radius of Investigation

X The radius of investigation, r_i, is the distance the pressure transient has moved into a formation following a rate change in a well.

X There are several equations that exist to calculate the radius of investigation. All the equations are square root equations based on cylindrical geometry, but each has its own coefficient that results in slightly different results, (See Oil and Gas Journal, Van Poollen, 1964).

X Use of the appropriate time is necessary to obtain a useful value of r_i. For a falloff time shorter than the injection period, use Agarwal equivalent time function, Δt_e, at the end of the falloff as the length of the injection period preceding the shut-in to calculate r_i.

X The following two equivalent equations for calculating r_i were taken from SPE Monograph 1, (Equation 11.2) and Well Testing by Lee (Equation 1.47), respectively:

$$r_i = \sqrt{0.00105 \frac{k \cdot t}{\phi \cdot \mu \cdot c_t}} \equiv \sqrt{\frac{k \cdot t}{948 \cdot \phi \cdot \mu \cdot c_t}}$$

Effective Wellbore Radius

X The effective wellbore radius relates the wellbore radius and skin factor to show the effects of skin on wellbore size and consequently, injectivity.

X The effective wellbore radius is calculated from the following:

$$r_{wa} = r_w e^{-s}$$

X A negative skin will result in a larger effective wellbore radius and therefore a lower injection pressure.

Reservoir Injection Pressure Corrected for Skin Effects

X The pressure correction for wellbore skin effects, ΔP_{skin}, is calculated by the following:

$$\Delta P_{skin} = 0.868 \cdot m \cdot s$$

where, m = slope of the semilog straight line, psi/cycle
s = wellbore skin, dimensionless

X The adjusted injection pressure, P_{wfa} is calculated by subtracting the ΔP_{skin} from the measured injection pressure prior to shut-in, P_{wf}. This adjusted pressure is the calculated reservoir pressure prior to shutting in the well, $\Delta t=0$, and is determined by the following:

$$P_{wfa} = P_{wf} - \Delta P_{skin}$$

X From the previous equations, it can be seen that the adjusted bottomhole pressure is directly dependent on a single point, the last injection pressure recorded prior to shut-in. Therefore, an accurate recording of this pressure prior to shut-in is important. Anything that impacts the pressure response, e.g., rate change, near the shut-in of the well should be avoided.

Determination of the Appropriate Fluid Viscosity

X If the wastestream and formation fluid have similar viscosities, this process is not necessary.

X This is only needed in cases where the mobility ratios are extreme between the wastestream, $(k/\mu)_w$, and formation fluid, $(k/\mu)_f$. Depending on when the test reaches radial flow, these cases with extreme mobility differences could cause the derivative curve to change and level to another value. Eliminating alternative geologic causes, such as a sealing fault, multiple layers, dual porosity, etc., leads to the interpretation that this change may represent the boundary of the two fluid banks.

X First assume that the pressure transients were propagating through the formation fluid during the radial flow portion of the test, and then verify if this assumption is correct. This is generally a good strategy except for a few facilities with exceptionally long injection histories, and consequently, large waste plumes. The time for the pressure transient to exit the waste front is calculated. This time is then identified on both the log-log and semilog plots. The radial flow period is then compared to this time.

X The radial distance to the waste front can then be estimated volumetrically using the following equation:

$$r_{waste\,plume} = \sqrt{\frac{0.13368 \cdot V_{waste\,injected}}{\pi \cdot h \cdot \phi}}$$

where, $V_{waste\ injected}$ = cumulative waste injected into the completed interval, gal
$r_{waste\ plume}$ = estimated distance to waste front, ft
h = interval thickness, ft
φ = porosity, fraction

X The time necessary for a pressure transient to exit the waste front can be calculated using the following equation:

$$t_w = \frac{126.73 \cdot \mu_w \cdot c_t \cdot V_{waste\,injected}}{\pi \cdot k \cdot h}$$

where, t_w= time to exit waste front, hrs
$V_{waste\ injected}$ = cumulative waste injected into the completed interval, gal
h = interval thickness, ft
k = permeability, md
μ_w = viscosity of the historic waste plume at reservoir conditions, cp
c_t = total system compressibility, psi^{-1}

X The **time should be plotted on both the log-log and semilog plots** to see if this time corresponds to any changes in the derivative curve or semilog pressure plot. If the time estimated to exit the waste front occurs before the start of radial flow, the assumption that the pressure transients were propagating through the reservoir fluid during the radial flow period was correct. Therefore, the viscosity of the reservoir fluid is the appropriate viscosity to use in analyzing the well test. If not, the viscosity of the historic waste plume should be used in the calculations. If the mobility ratio is extreme between the wastestream and formation fluid, adequate information should be included in the report to verify the appropriate fluid viscosity was utilized in the analysis.

Reservoir Thickness

X The thickness used for determination of the permeability should be justified by the operator. The net thickness of the defined injection interval is not always appropriate.

X The permeability value is necessary for plume modeling, but the transmissibility value, kh/μ, can be used to calculate the pressure buildup in the reservoir without specifying values for each parameter value of k, h, and μ.

X Selecting an interval thickness is dependent on several factors such as whether or not the injection interval is composed of hydraulically isolated units or a single massive unit and wellbore conditions such as the depth to wellbore fill. When hydraulically isolated sands

are present, it may be helpful to define the amount of injection entering each interval by conducting a flow profile survey. Temperature logs can also be reviewed to evaluate the intervals receiving fluid. Cross-sections may provide a quick look at the continuity of the injection interval around the injection well.

X A copy of a SP/Gamma Ray well log over the injection interval, the depth to any fill, and the log and interpretation of available flow profile surveys run should be submitted with the falloff test to verify the reservoir thickness value assumed for the permeability calculation.

Use of Computer Software

X To analyze falloff tests, operators are encouraged to use well testing software. Most software has type curve matching capabilities. This feature allows the simulation of the entire falloff test results to the acquired pressure data. This type of analysis is particularly useful in the recognition of boundaries, or unusual reservoir characteristics, such as dual porosity. It should be noted that type curve matching is not considered a substitute, but is a compliment to the analysis.

X All data should be submitted on a CD-ROM with a label stating the name of the facility, the well number(s), and the date of the test(s). The label or READ.Me file should include the names of all the files contained on the CD, along with any necessary explanations of the information. The parameter units format (hh:mm:ss, hours, etc.) should be noted for the pressure file for synchronization to the submitted injection rate information. The file containing the gauge data analyzed in the report should be identified and consistent with the hard copy data included in the report. If the injection rate information for any well included in the analysis is greater than 10 entries, it should also be included electronically.

Common Sense Check

X After analyzing any test, always look at the results to see if they "make sense" based on the type of formation tested, known geology, previous test results, etc. Operators are ultimately responsible for conducting an analyzable test and the data submitted to the regulatory agency.

X If boundary conditions are observed on the test, review cross-sections or structure maps to confirm if the presence of a boundary is feasible. If so, the boundary should be considered in the AOR pressure buildup evaluation for the well.

X Anomalous data responses may be observed on the falloff test analysis. These data anomalies should be evaluated and explained. The analyst should investigate physical causes in addition to potential reservoir responses. These may include those relating to the well equipment, such as a leaking valve, or a channel, and those relating to the data

acquisition hardware such as a faulty gauge. An anomalous response can often be traced to a brief, but significant rate change in either the test well or an offset well.

X Anomalous data trends have also been caused by such things as ambient temperature changes in surface gauges or a faulty pressure gauge. Explanations for data trends may be facilitated through an examination of the backup pressure gauge data, or the temperature data. It is often helpful to qualitatively examine the pressure and/or temperature channels from both gauges. The pressure data should overlay during the falloff after being corrected for the difference in gauge depths. On occasion, abrupt temperature changes can be seen to correspond to trends in the pressure data. Although the source of the temperature changes may remain unexplainable, the apparent correlation of the temperature anomaly to the pressure anomaly can be sufficient reason to question the validity of the test and eliminate it from further analysis.

X The data that is obtained from pressure transient testing should be compared to permit parameters. Test derived transmissibilities and static pressures can confirm compliance with non-endangerment (Area Of Review) conditions.

APPENDIX F - PLUGGING AND ABANDONMENT PLANS

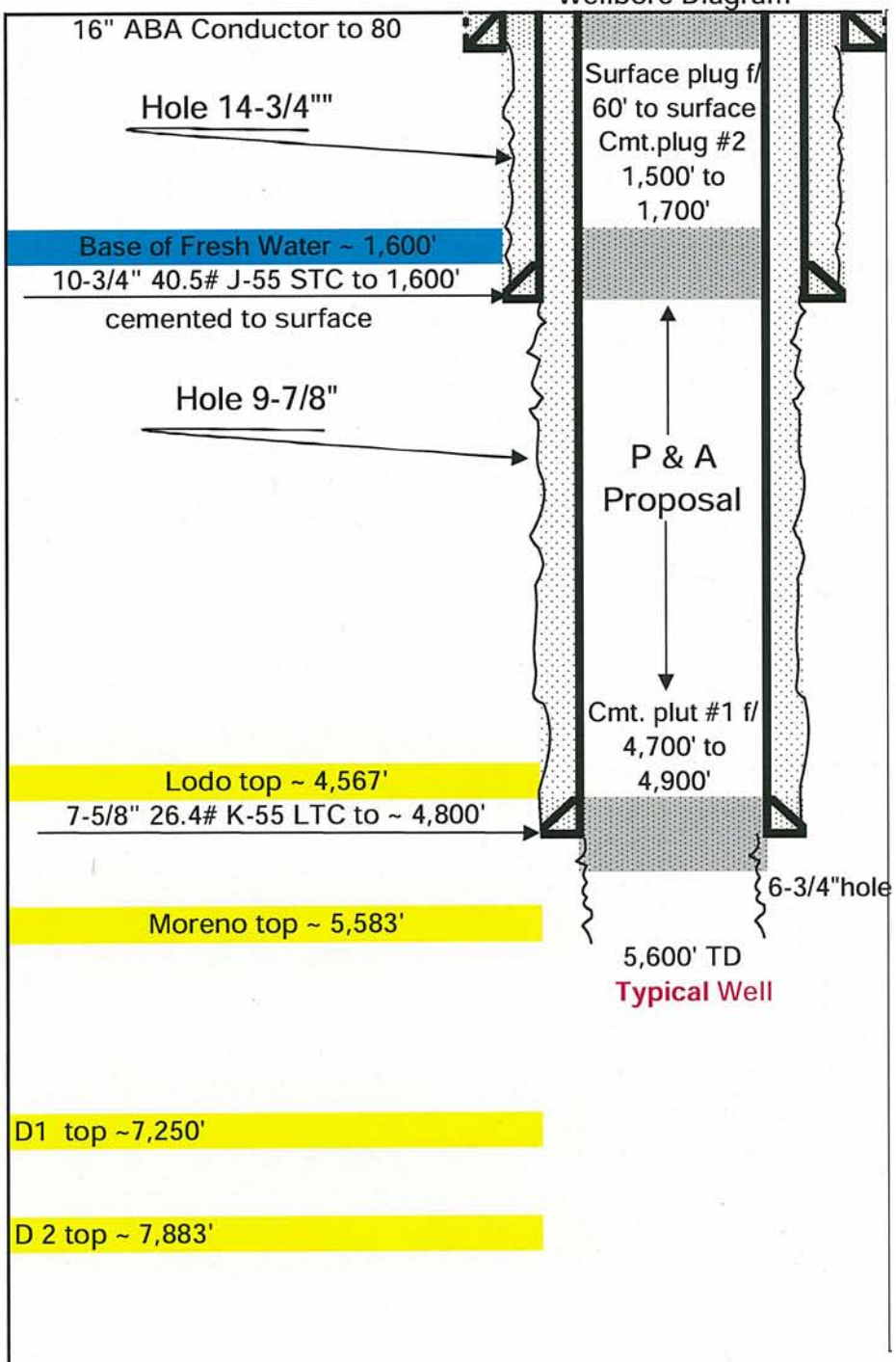
Upon completion of injection activities the well(s) shall be abandoned according to State and Federal regulations to ensure protection of Underground Sources of Drinking Water.

PLAN A

Well : IW1 - **IW6**

Surface Location: **See Plan**

Wellbore Diagram



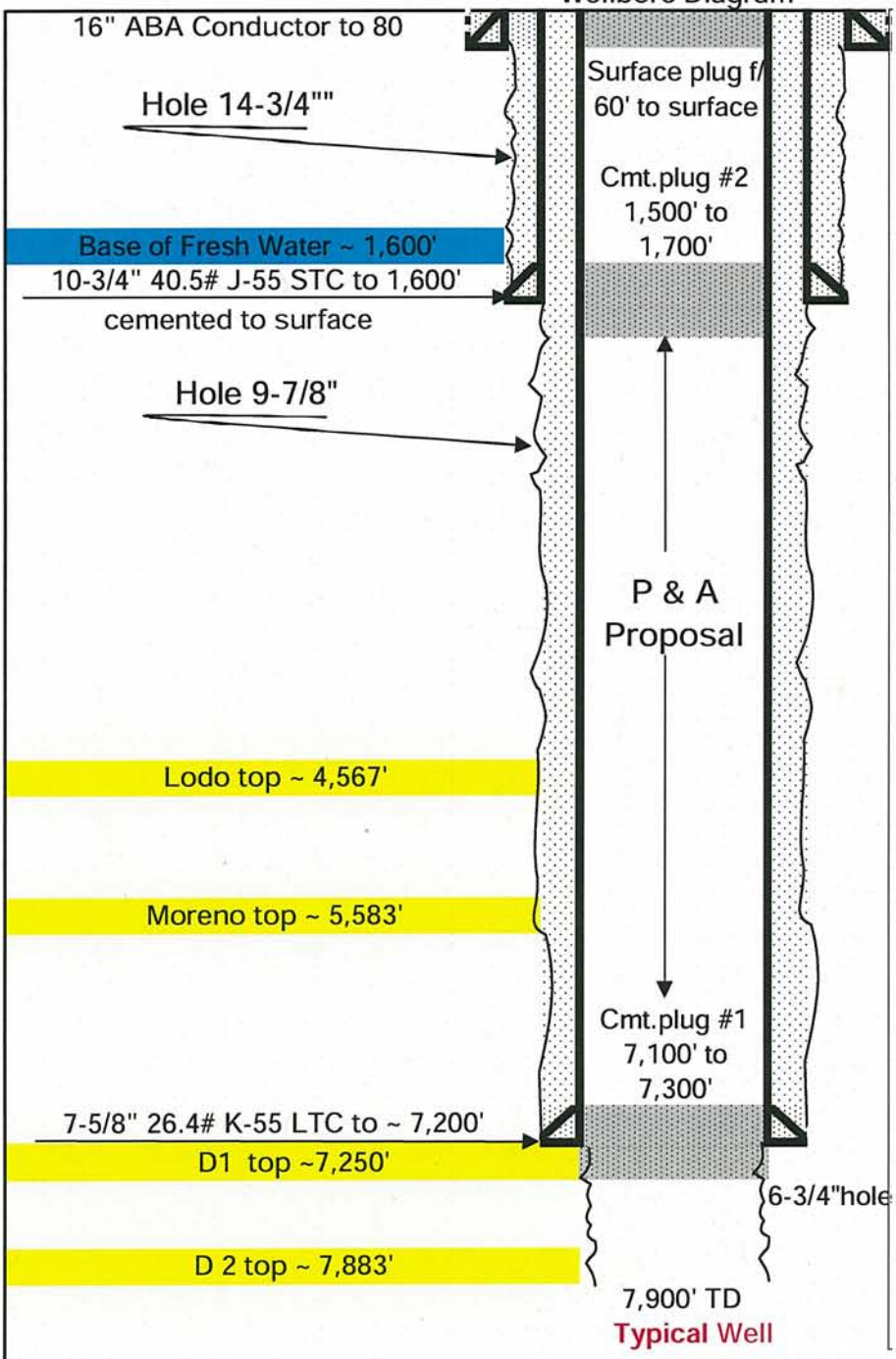
Hole Size	Depth	Casing
20"	80'	16" conductor
14-3/4"	1,600'	10-3/4", 40.5#, J-55, STC R3
9-7/8"	4,800'	7-5/8", 26.4#, K-55, LTC R3
6-3/4"	5,600'	5", 15#, K-55, LTC R3

PLAN B

Well : **IW1 - IW6**

Surface Location: **See Plan**

Wellbore Diagram



Hole Size	Depth	Casing
20"	80'	16" conductor
14-3/4"	1,600'	10-3/4", 40.5#, J-55, STC R3
9-7/8"	7,200'	7-5/8", 26.4#, K-55, LTC R3
6-3/4"	7,900'	5", 15#, K-55, LTC R3