Phase 3 Extraction Protocol

Aliso Canyon RCA:
SS-25 Phase 3 Tubing, Casing, Wellhead Extraction Protocol

Prepared For:

SS-25 RCA:

SoCalGas, CPUC, DOGGR

Purpose:
To capture the key planning information needed for the extraction and recovery of tubing, casing, wellhead, and the abandonment of the Aliso Canyon SS-25 well.

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BLADE ENERGY PARTNERS

2600 Network Boulevard, Suite 550
Frisco, Texas 75034

+1 972-712-8407 (phone)
+1 972-712-8408 (fax)

16285 Park Ten Place, Suite 600
Houston, Texas 77084

1-800-319-2940 (toll free)
+1 281-206-2000 (phone)
+1 281-206-2005 (fax)

www.blade-energy.com

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1 Introduction

The purpose of this document is to capture the key planning and design information necessary for utilization in Phase 3 of the Aliso Canyon SS-25 Root Cause Analysis involving the extraction of the Well SS-25 tubing, casing and wellhead and its subsequent permanent abandonment.

This document describes the overall operational concept for the tubulars extraction effort and the abandonment process. The established SoCalGas Phase III Investigation SS-25 Well Site Safety and Emergency Response Plan remains in effect and all personnel onsite have "stop-work" responsibility and authority if safety is an immediate concern or the action could lead to an unsafe condition.

During Phase 3, the Blade Team and those parties under Blade's direction are responsible for directing the work of contractors retained to perform the extraction of Well SS-25 tubing, casing, and wellhead and protection of associated evidence. The person in charge (PIC) of the extraction activities and protection of evidence on-site is the Blade Team Lead, Ravi Krishnamurthy. SoCalGas and those parties under SoCalGas' direction are responsible for directing the contractors who will perform the permanent abandonment of SS-25. Should clarification be required or disagreements arise between Blade and SoCalGas; the CPUC, DOGGR, Blade, and SoCalGas (the entities) shall meet and approve forward going steps. If the entities are unable to agree on any activities described for Phase 3, Blade will document such differences and the designated regulatory agency will act as the arbiter, and make the final decision.

Phase 3 is a complex process of protocols, work plans and operations and requires close coordination and cooperation between all the stakeholders – Blade, SoCalGas, CPUC, DOGGR and the various service companies that will be providing the necessary equipment and services. The Phase 3 plan is subject to change as additional information from the well and other data may become available. Throughout the process at least daily, the entities shall informally review the Phase 3 plan. In addition, the Phase 3 Extraction Protocol and Phase 3 plan will be formally reviewed at the end of each sub-phase. If a situation occurs when site dynamics change and a real-time human decision is required; the PIC or SoCalGas (for safety related) may take immediate mitigating or abating action. In addition, Blade reserves the right to deviate from these procedures and protocols as unique situations arise in the field. Furthermore, the Blade team shall document any significant deviation from these procedures and protocols that may affect the ability to safely P&A the well or collect data and evidence for RCA purposes, and notify the CPUC, DOGGR and SoCalGas. Blade shall obtain approvals from the CPUC, DOGGR and SoCalGas in advance of the affected activity. If the entities are unable to agree on any activities described for Phase 3, Blade shall document such differences, and the designated regulatory agency will act as the arbiter and make the final decision.

Blade, the CPUC, DOGGR and SoCalGas personnel (including advisors, consultants and contractors) will be present during all activities of Phase 3.

The structure of this document is described below.

- Section 2 includes the objectives of the extraction phase.
- Section 3 discusses rig types and plans.
- Section 4 includes key principles that will guide the implementation of Phase 3.

- Section 5 provides basic information about the SS-25 well history and the geology.
- Section 6 provides details of the SS-25 well status after the relief well operations.
- Section 7 provides details of the current status of SS-25 after Phase 1.
- Section 8 addresses the key Phase 3 planning assumptions and operational concepts.
- Section 9 has an executive summary of the operational procedures.
- Section 10 provides a list of the equipment and services that will be required.
- Section 11 onwards are Appendices that contain drilling history information for the SS-25, SS-25A, SS-25B and P-39A wells, and other well details.

1.1 List of Abbreviations

ADR	Automated Drilling Rig
BBLS	Barrels
BFW	Below Fresh Water
BHP	Bottom Hole Pressure
BHT	Bottom Hole Temperature
BOP	Blowout Preventer
BOPE	Blowout Preventer Equipment
BPV	Back Pressure Valve
C&C	Circulate and Condition
CIBP	Cast Iron Bridge Plug
DSA	Double Studded Adaptor
DTS	Distributed Temperature Sensors
EMW	Equivalent Mud Weight
ETOP	Extract Tubulars on Paper
FP	Free Point
GLE	Ground Level Elevation
HAZid	Hazard Identification
HPT	High Precision Temperature
LCM	Lost Circulation Material
LD	Lay Down
MID	Magnetic Imaging Defectoscope
MIRU	Move In Rig Up
MU	Make Up
ND	Nipple Down
NTU	Nephelometric turbidity unit
NU	Nipple Up
P&A	Plug and Abandon
PBTD	Plug Back Total Depth
PIC	Person in Charge
POH	Pull Out of Hole
PPG	Pounds per Gallon
RBP	Retrievable Bridge Plug
RCA	Root Cause Analysis
RIH	Run In Hole
RU	Rig Up
SNL	Spectral Noise Log
TH	Tubing Head
TD	Total Depth
TOC	Top of Cement
TOF	Top of Fish
TOL	Top of Liner
TP&A	Temporarily Plug and Abandon
WBM	Water Based Mud

2 Extraction Phase Objectives

The removal of the tubulars from the SS-25 well for detailed examination and metallurgical testing is a fundamental and integral part of the RCA in order to determine the mode of downhole failure so as to determine the root cause and potential contributing factors. As such, the main objectives of this phase are as follows:

1. Permanently abandon the well in a manner that meets all SoCalGas requirements, all DOGGR regulatory requirements, and industry best practices.
2. Recover as much of the down-hole equipment as possible, including but not limited to the production tubing, production casing, and the wellhead whilst maintaining the primary objective of safely plugging and abandoning the well. The key components of this operation are shown below.
   A. Cut and recover as much of the 2-7/8" tubing as possible. The estimated TOC in the 2-7/8” x 7” annulus is at 7,590 ft.

   B. Conduct diagnostic wireline log inspections of the 7” and 11-3/4" casing strings.

   C. Recover as much of the 7” casing as is feasible. Recovering the 7” casing from below water flood zone at ~4,600 ft is preferred. The feasibility of recovering 7” casing below the 11-3/4” casing shoe will be evaluated using the 7” casing log data.

      The 7” MID-2 log results show indications of significant metal loss at 895 ft and at 4,456 ft in the 7” casing. Recovery of casing with these indications is of great interest to the RCA.

   D. Confirming the pressure integrity of the 11-3/4” casing is necessary for recovering the 7” casing and the subsequent P&A operations.

      The 11-3/4” MID-3 log results show indications of significant metal loss at 151 ft and at 192 ft.

   E. Recover the wellhead and tree.

3 Rig Types for Phase 3

Two different types of rigs are planned for the Phase 3 RCA work on SS-25. A workover rig will be used for the tubing extraction and logging part of the work and a small foot print drilling rig will be used for the remaining work.

3.1 Rig for Tubing Extraction and 7" Casing Logging

The workover rig Ensign #334 (or equivalent rig) will be used for Phase 3A. Phase 3A includes pulling and laying down the 2-7/8" tubing and logging the 7" casing. After logging, the rig operations will be shut down for log evaluation and approval of next steps.

Ensign #334 was used for similar operations on Well SS-25A starting in May 2017. The 5-1/2" tubing pulling and laying down operations for SS-25A went according to plans as described in the Blade SS-25A Tubulars Handling Protocol. The hook loads for the 2-7/8" tubing in SS-25 are around one third of the 5-1/2" tubing hook loads in SS-25A. The rig floor of a workover rig is large enough for the tubing tongs and operator and the rig crew for handling and laying down tubing.

The rig crews on Ensign #334 gained experience and understand the requirements for laying down tubing for the RCA process. The rig and rig equipment are well suited for preparing the well for logging and logging operations. The derrick has sufficient height for handling the long lubricator required for the logging tool strings. The workover rig can move, rig up and rig down much quicker than a drilling rig. Therefore the plan is to use a workover rig for Phase 3A of the RCA. A photograph of Ensign #334 workover rig on SS-25A is shown in Figure 1.

A pump stroke counter was added to Ensign #334 after the SS-25A work was started to aid in keeping track of fluid volumes pumped.

A trip tank will be used for the SS-25 work to monitor fluid volumes in the well during trips.

Figure 1. Ensign #334 on Well SS-25A in May 2017. Well SS-25 is located in the foreground between the rig and logging truck.

3.2 Rig for Casing Extraction and P&A

A small foot print automated drilling rig (ADR) rig is planned for the Phases after Phase 3A. Ensign #540 has been selected for the work. This is a modular type rig designed for pad drilling, and therefore provides added flexibly for placing the rig components on the narrow SS-25 location. The rig layout and summary of the rig equipment and specifications are shown in Figure 2.

A drilling rig is better suited for handling and laying down the 7” casing. The pumps and mud system are required in case there is a need to wash over and fish the 7” casing. Therefore the plan is to release the workover rig after Phase 3A tubing extraction and 7” casing logging and move in the Ensign #540 in preparation for extracting the 7” casing as required by the RCA.

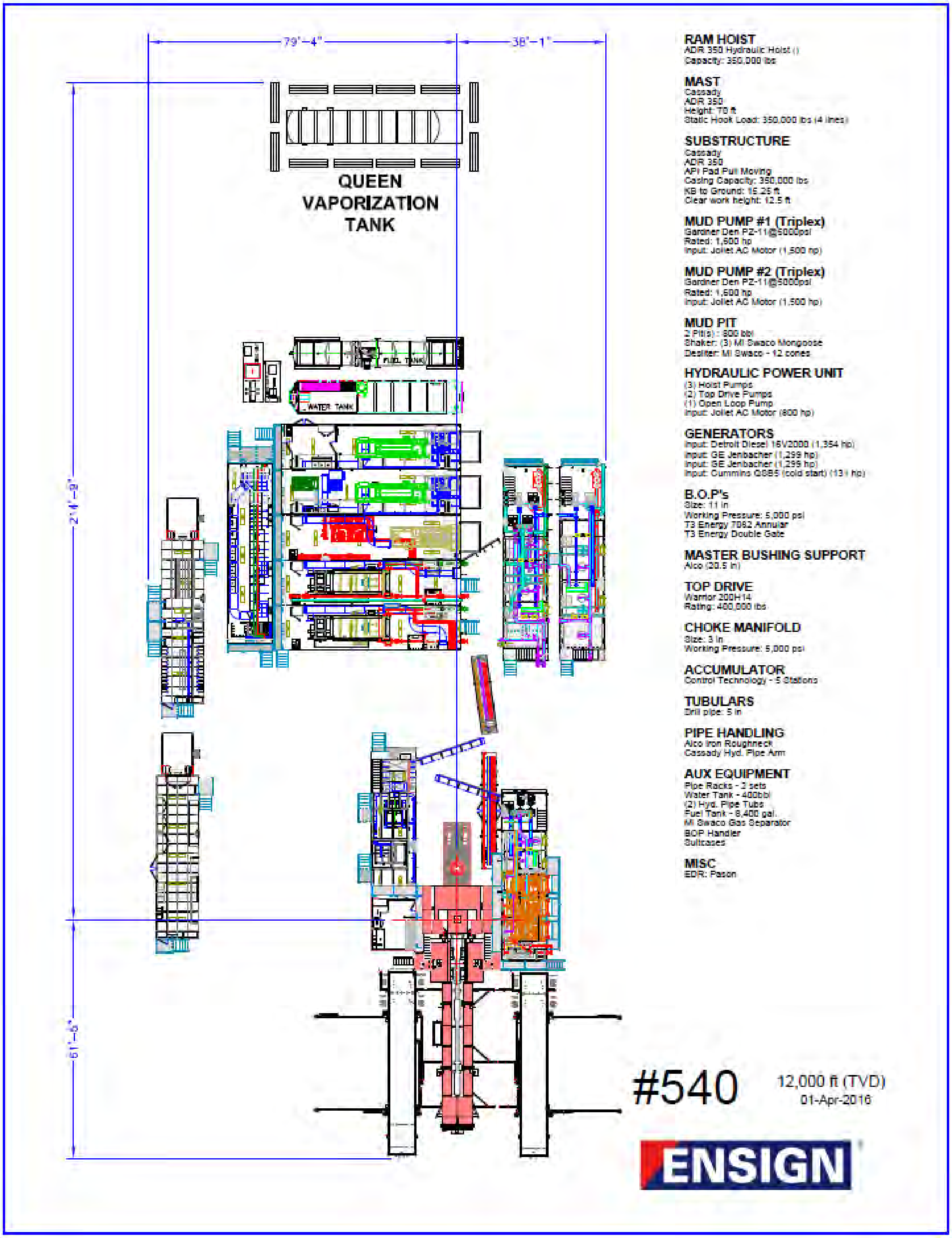


Figure 2. Ensign 540 Equipment Layout

4 Guiding Principles

The following umbrella principles will serve as the basis for planning and implementing the Phase 3 Extraction Protocol operations.

1. The CPUC, DOGGR and SoCalGas will review, provide input and approve detailed Operational Work Plans prepared by Blade.
2. Blade will develop supplemental protocols as needed, and based on information gathered and actual results obtained during the operational sequences.
3. Blade retains final responsibility for determining the procedural steps necessary to meet the objectives in the protocol and the overall RCA effort. Any significant deviations that may affect the ability to safely P&A the well or collect data and evidence for RCA purposes require approval by SoCalGas, the CPUC and DOGGR.
4. Blade retains final responsibility related to directing the work to perform the extraction of down-hole tubing, casing and wellhead retrieval and completing the Phase 3 operations according to the Protocol. Should Blade choose to deviate from the planned operations, Blade will prepare a document that led to their recommendation.
5. Blade retains final responsibility for determining the disposition of all material removed from the wellbore.
6. SoCalGas retains final responsibility for implementing those procedures and processes that affect the final disposition of the well - i.e., insuring that the final P&A satisfies SoCalGas, DOGGR District requirements, any designated regulatory agency requirements and industry best practices.
7. SoCalGas retains final responsibility for determining safety, decontamination and site access procedures throughout the execution of future protocols.
8. All personnel onsite have "stop-work" responsibility and authority if safety is an immediate concern or if the action that could lead to an unsafe condition.
9. No provisions contained in any protocol will supersede necessary actions identified for the immediate mitigation of any recognized hazard directly affecting life, personnel safety, the public, or the environment. Furthermore, the SoCalGas Phase III Investigation SS25 Well Site Safety and Emergency Response Plan remains in effect.
10. SoCalGas, Blade, the Rig Contractor and affected Service Company personnel will conduct a separate Job Safety Analysis consistent with SoCalGas established procedures for each step or series of steps of the operations work plan.
11. QA/QC procedures will be developed for key services, equipment and tools that will be used during the extraction operation.
12. An Extract Tubulars on Paper (ETOP) exercise will be held prior to the commencement of operations with all stakeholders including the rig and service company personnel. The purpose of the ETOP will be to conduct a step-by-step review of the operational steps, identify risks and mitigations, discuss preparation requirements, solicit ideas for improvements / efficiencies, and ensure that roles and responsibilities are clearly understood. Blade will modify the final operational work plans to incorporate feedback from this meeting.

5 SS-25 Well Data

This section provides reference information about the SS-25 well, in particular - the well architecture, the geology, the drilling history, and the status of the well through the end of the relief well operations in February 2016.

A summary of the drilling history is provided below, and schematics showing the well's architecture at the time it was converted for gas storage are shown in Figure 3 and Figure 4. The well's directional profile is shown in Figure 5. Note that the survey data shown is based on the Scientific Drilling gyro survey run in January 2016 *(SS-25 INRUN 1 16 16.pdf*) that went to 8,378 ft MD and not all the way to TD. Sections 5.2 and 5.3 discuss the geology (formation tops, lithology, etc.) and the bottom hole pressures and temperatures. A comparison between the SS-25 well and several analog wells is provided in Section 5.4.

5.1 Well History Summary

Drilling operations commenced on the SS-25 well on 1 October 1953. A 10-5/8" hole was drilled to 2,567 ft and then opened to 16" to 990 ft where an 11-3/4" surface casing string was run and cemented, The 10-5/8" hole was drilled to 4,948 ft where the drill string became stuck while running a Johnson formation test tool. Fishing was unsuccessful leaving the TOF at 3,967 ft. A cement plug was set at 3,830 ft. An open hole whipstock was run and the well was sidetracked at 3,860 ft. A 10-5/8" hole was drilled to 4,661 ft. The hole size was reduced to 8-1/2", and drilled to 4,840 ft where a Johnson formation tester was run. The hole was opened up to 10-5/8" and drilling continued to 5,450 ft. An 8-1/2" hole was drilled to 5,945 ft. The hole was opened up to 10-5/8" and drilling continued to 7,917 ft where an open hole whipstock was run and the hole sidetracked for an apparent directional correction. Drilling continued to 8,585 ft at which point a 7" production string was run and cemented. A 6.0" hole was then drilled to TD at 8,749 ft MD / 8,733 ft TVD with a 10.6 ppg mud. 189 ft of 5-1/2" slotted liner was then run in the open hole. The well was completed and placed on production.

The following is a summary of the notable events that occurred while drilling:

- Lost returns while drilling at 169 ft
- Lost returns while drilling at 741 ft
- Lost returns while cementing the 11-3/4" casing at 990 ft requiring a top job to bring cement to surface.
- Twisted off drill collar at 2,925 ft (successfully recovered)
- Twisted off drill string at 3,073 ft (successfully recovered)
- Switched over to a Carbonox mud system at 4,350 ft
- Schlumberger electric logs run at 4,630 ft
- Ran electric logs and a Johnson formation tester at 4,781 ft. The BHP was reported at 1100 psi.
- Ran electric logs and a Johnson formation tester at 4,910 ft. The BHP was reported at 1250 psi.
- Ran electric logs at 4,948 ft

- Two 60 sack cement plugs were set at 4,948 ft to apparently plug back and isolate a water zone based on logs and the DST.
- A Johnson formation tester was run 4,860 ft. The tool became stuck after the formation test and could not be recovered.
- The well was TP&A'd and the rig was released. Operations were suspended for 42 days while a new rig was brought in.
- A cement plug was set to 3,830 ft and the well was sidetracked off an open hole whipstock at 3,860 ft.
- Ran electric logs and a Johnson formation tester at 4,680 ft. The BHP was not reported.
- Ran electric logs at 5,630 ft.
- Ran a Johnson formation tester at 5,645 ft. The BHP was not reported.
- Stuck the drill pipe 138 ft off bottom after drilling to 7,594 ft. Successfully pulled free.
- Apparent directional correction using an open hole whipstock at 7,917 ft
- Drilled to 8,093 ft and had to ream a key seat from 3,800 to 3,900 ft.
- Ran electric logs at 8,580 ft.
- Ran and cemented 7" casing at 8,585 ft.
- Ran a Johnson formation tester at 8,434 ft to test the WSO perforations.
- The rig was released on 20 February 1954.

After some 20 years as an oil producer, the SS-25 well was then converted to a gas storage well in June 1973. This involved pulling the existing tubing and packer and installing a new casing head on the 11-3/4" casing. A new 2-7/8" tubing string and completion was then run to 8,492 ft. The well was worked over in July 1976 and again in February 1979. The workover in 1979 was to replace CAMCO Annular Flow Safety System. The safety system inner flow tube mandrel was subsequently removed in 1979 when it failed to test.

The CAMCO SC1 Annular Flow Safety System concept was to use tubing pressure to open the ported nipple to allow communication for annular injection or production. If the tubing pressure was bled off, the annulus flow path would close. This system was developed due to a lack of available technology for setting and operating a deep surface controlled subsurface safety valve at the time. With the wireline removable SC-1 valve inner flow tube mandrel removed, as was done on SS-25 in 1979, the tubing and casing were in communication above the packer. The well had the capability of injecting and producing through both the tubing and annulus simultaneously.

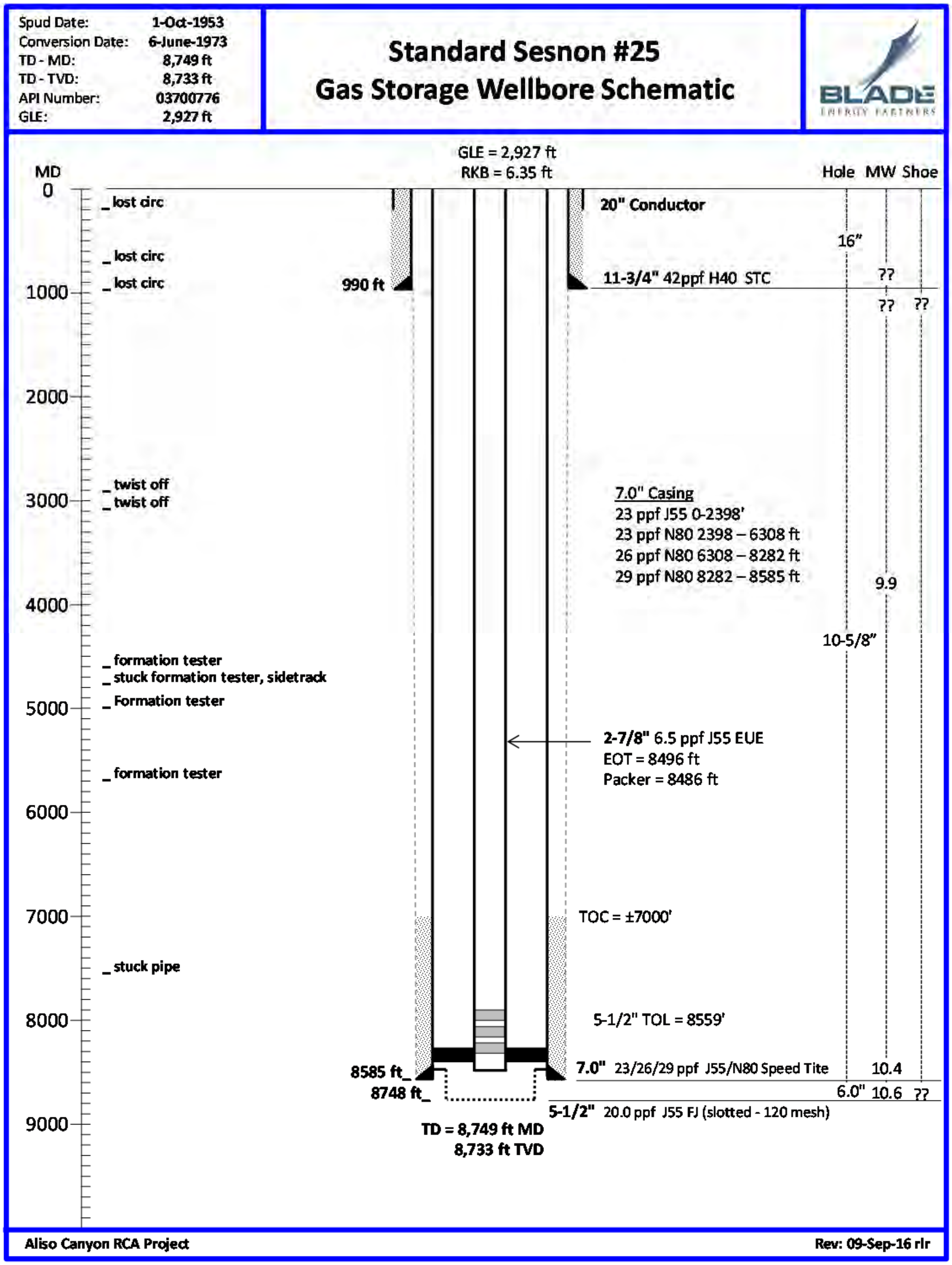


Figure 3. SS-25 Gas Storage Wellbore Configuration

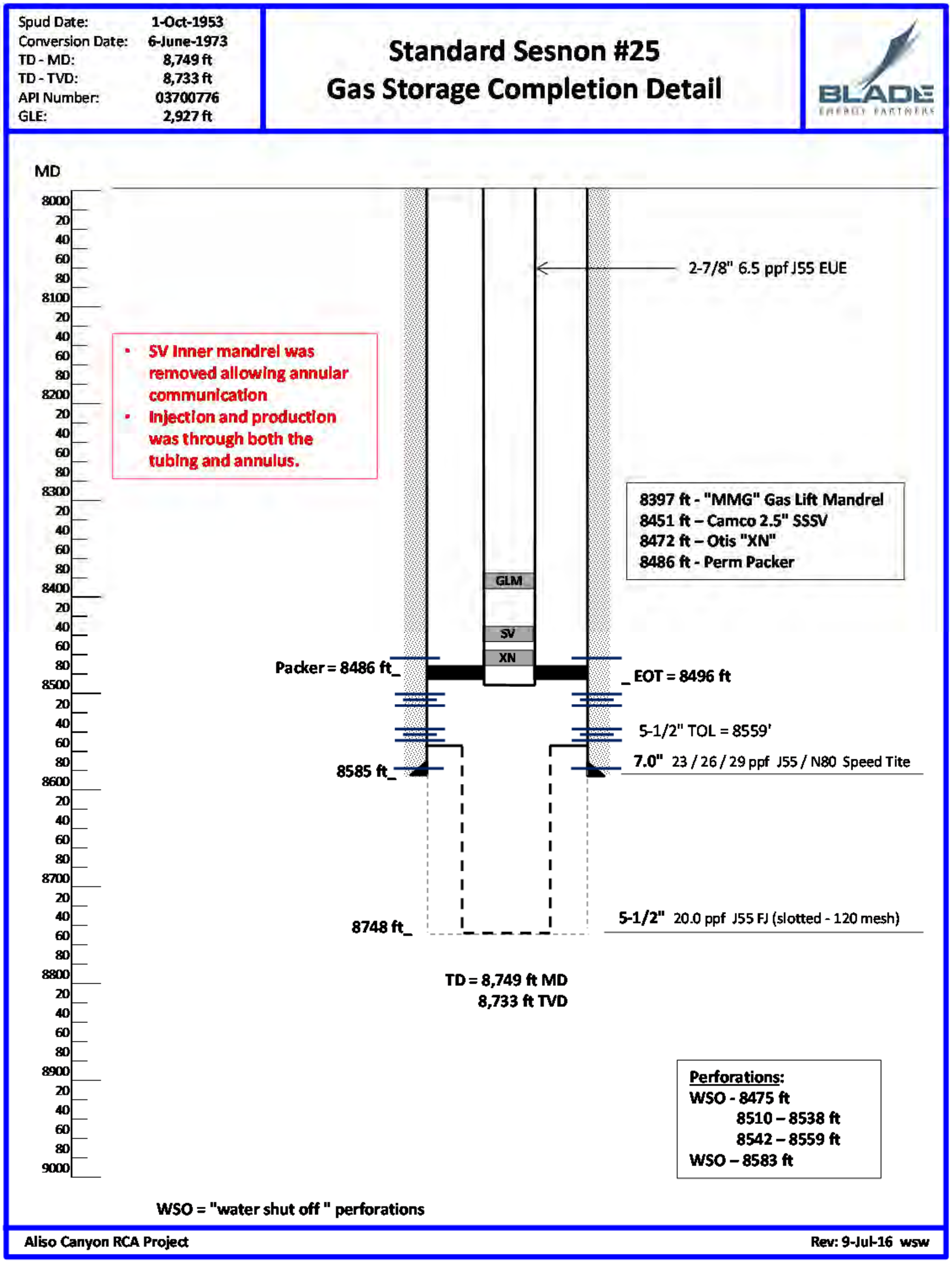


Figure 4. SS-25 Gas Storage Wellbore Configuration – Completion Detail

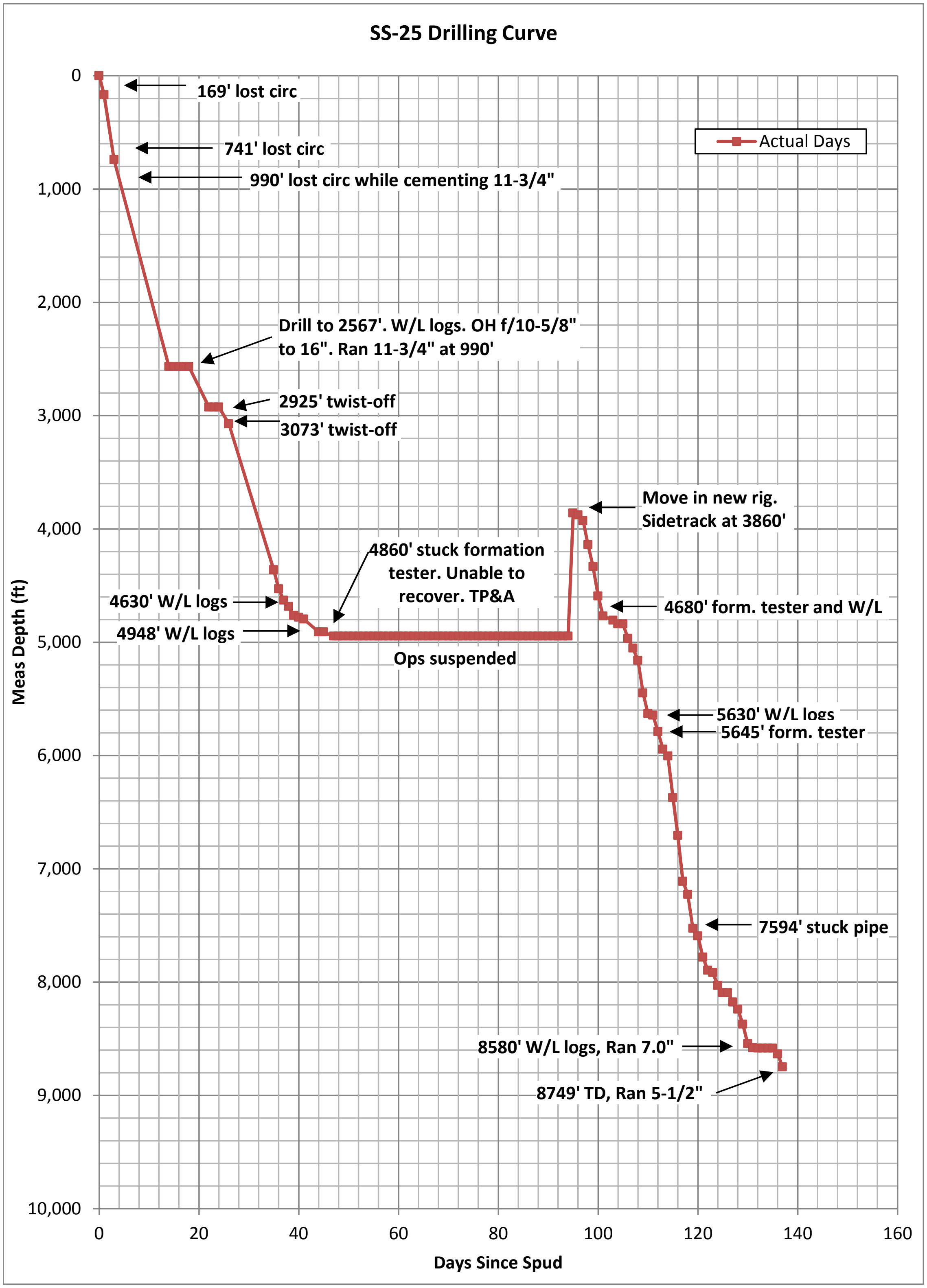


Figure 5. SS-25 Drilling Curve

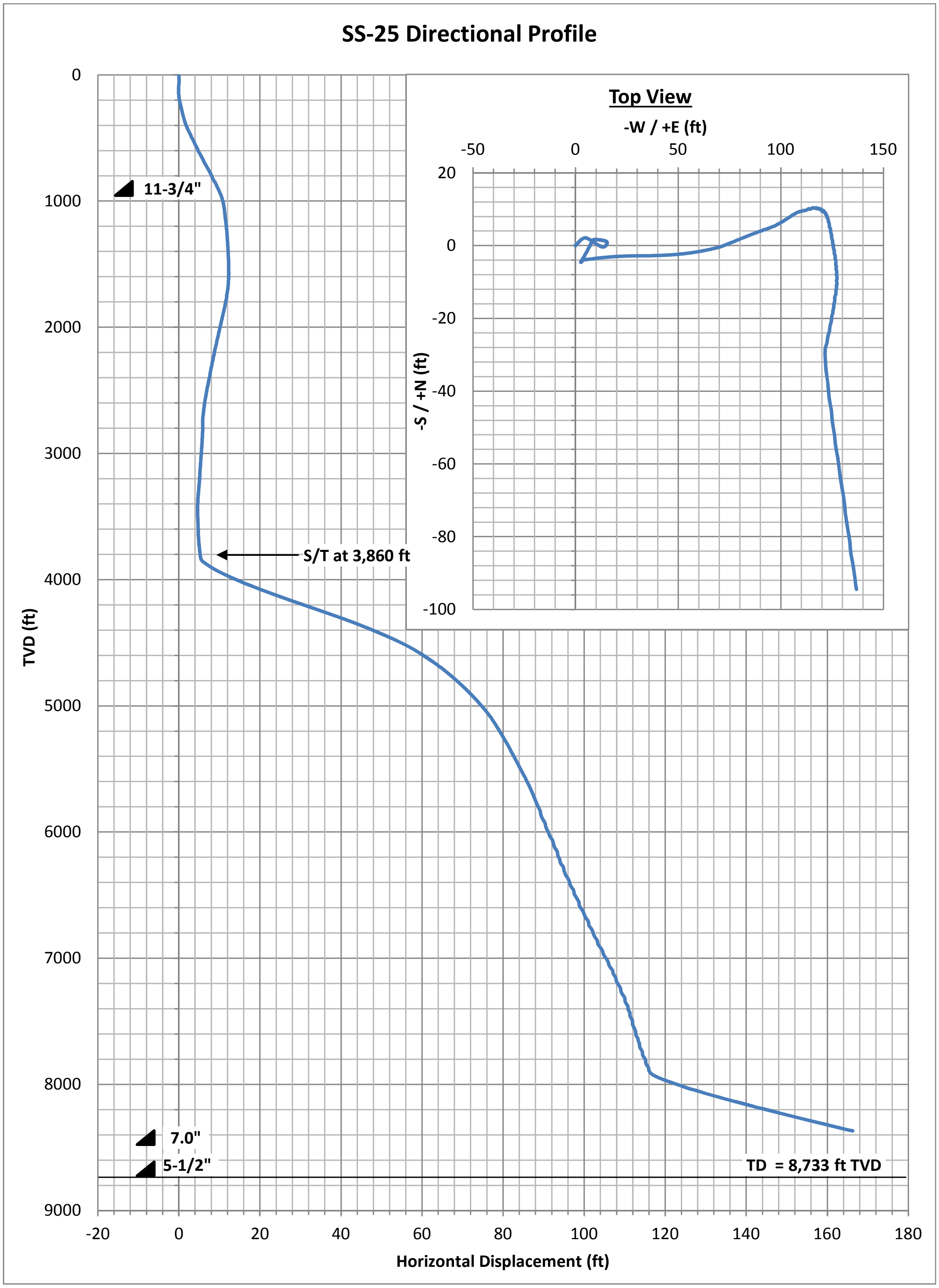


Figure 6. SS-25 Directional Profile

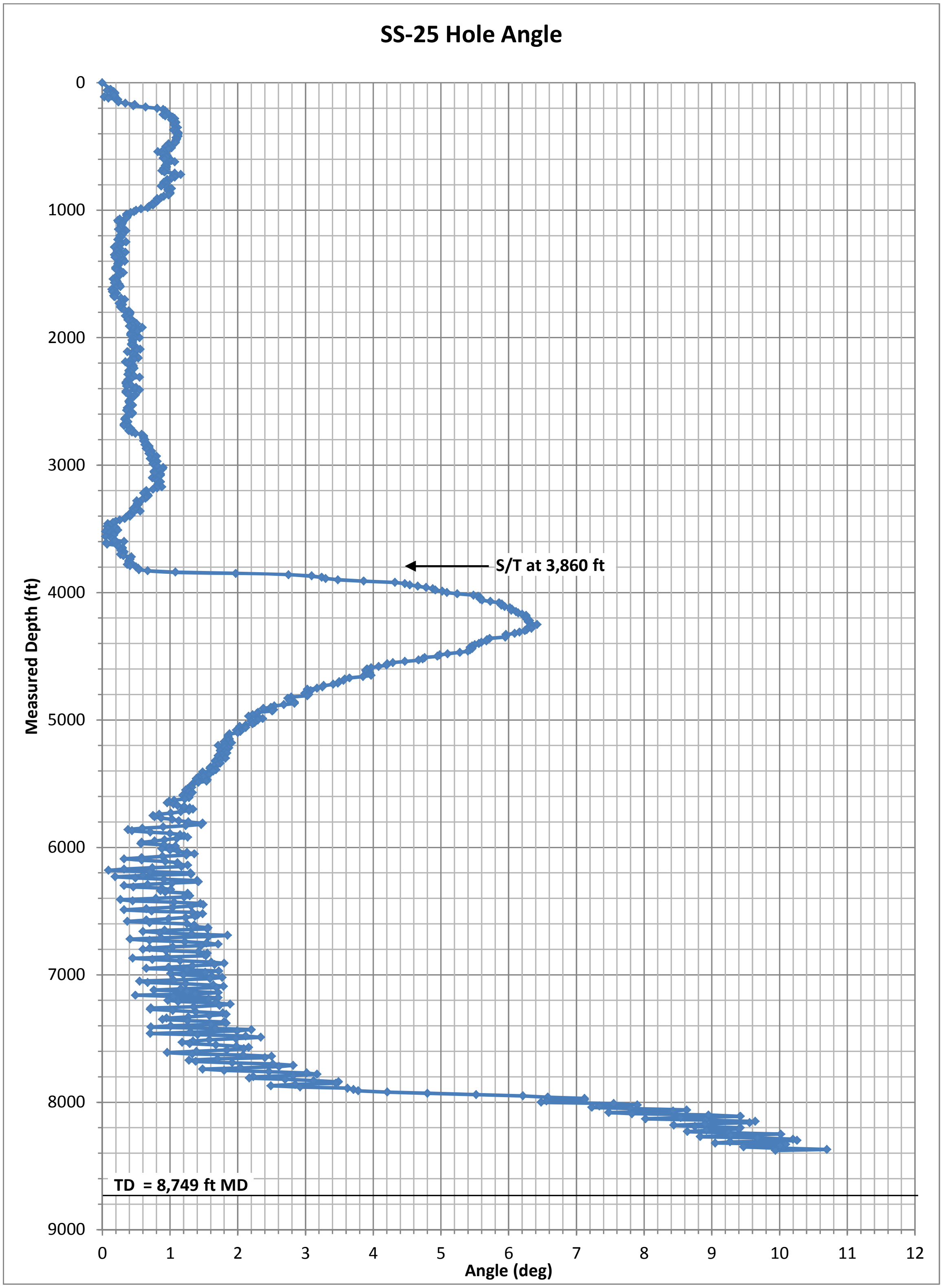


Figure 7. SS-25 Hole Inclination vs. Depth

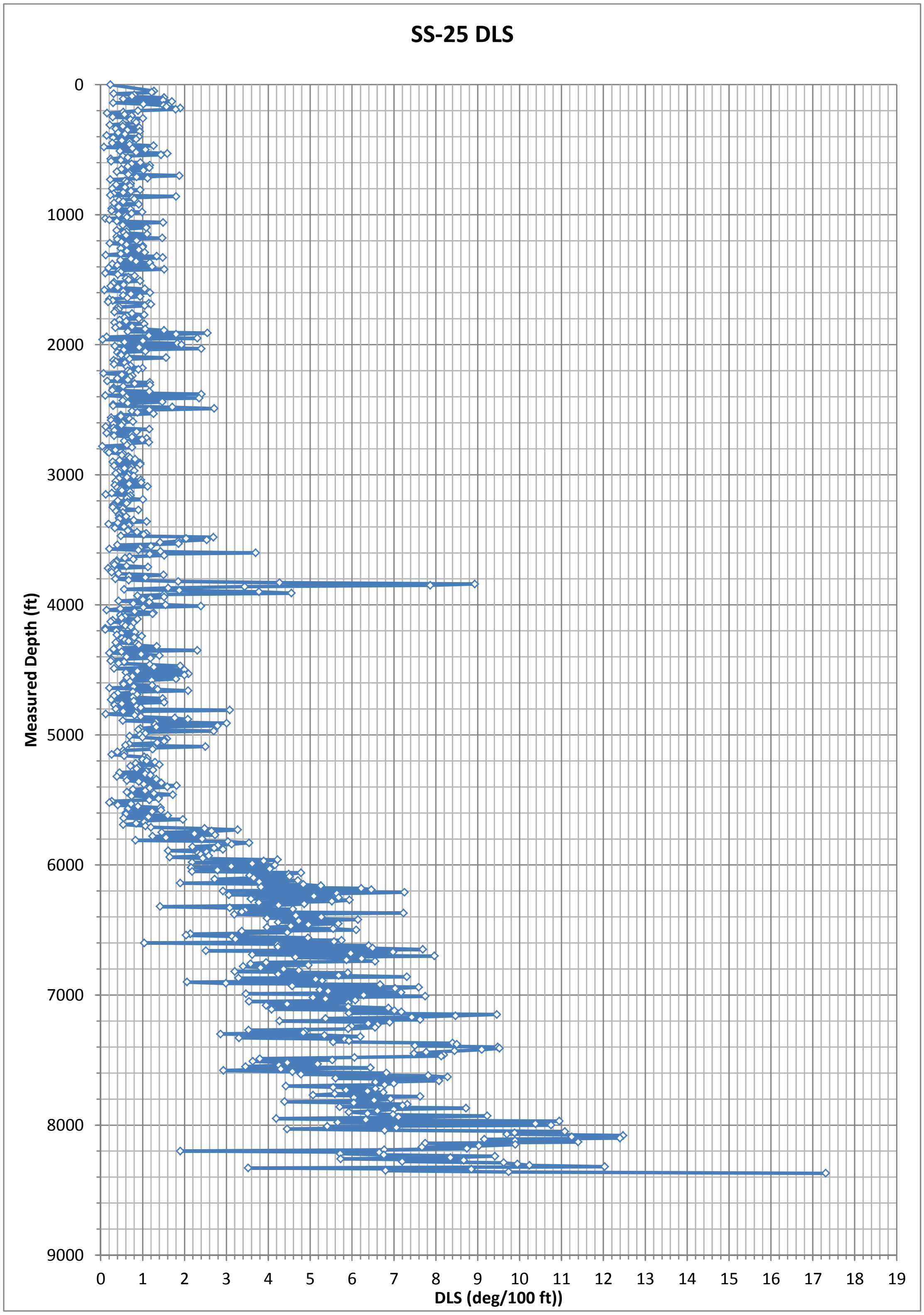


Figure 8. SS-25 Dogleg Severity vs. Depth

5.2 Geologic Information

Aliso Canyon Field well SS-25 is located in the California Transverse Range geomorphic province, southeast Ventura basin in the foothills of Oat Mountain. The surface terrain is rugged with vertical relief of approximately 200-300 ft between the SS-25 location on the ridge with adjacent drainages. The surface formation at the wellsite of the SS-25 is the Modelo which is of deep marine origin and consists of hard fractured porcelanite and porcelaneous shale interbedded with punky shale, siltstones and clay.

5.2.1 Subsurface Structure

As illustrated in Figure 9 and Figure 10, the subsurface penetrated by SS-25 is characterized by two main tectonic thrusting events. The first event, the Older Susana thrust fault (OSST) at 1,635 ft which thrusted Middle Miocene age rock (Modelo and Topanga formations) over younger sections of Pliocene age (Pico formation). The second event, the Younger Santa Susana Thrust fault (YSST) at 4,200 ft is internal within the Pico formation, thrusting Pico over Pico. At the SS-25 location, the thrust plane of the Older Santa Susana Thrust fault cuts through interbedded kaolinized sands and clay, while the second Younger Santa Susana Thrust cuts along a Pico claystone unit at 4,200 ft. The Younger Santa Susana Thrust fault provides the structural trap for the sub-thrust Pliocene Pico reservoirs and gas storage reservoirs in the Miocene Modelo or Sesnon S1-S14 zones in SS-25. Structural dip of the OSST at the SS-25 location is 15°N and 55°NE for the YSST. Pliocene and Miocene formations below the Younger Santa Anna Thrust are productive, and are comprised of the Aliso, Porter, Del Aliso Zones and Sesnon Zones.

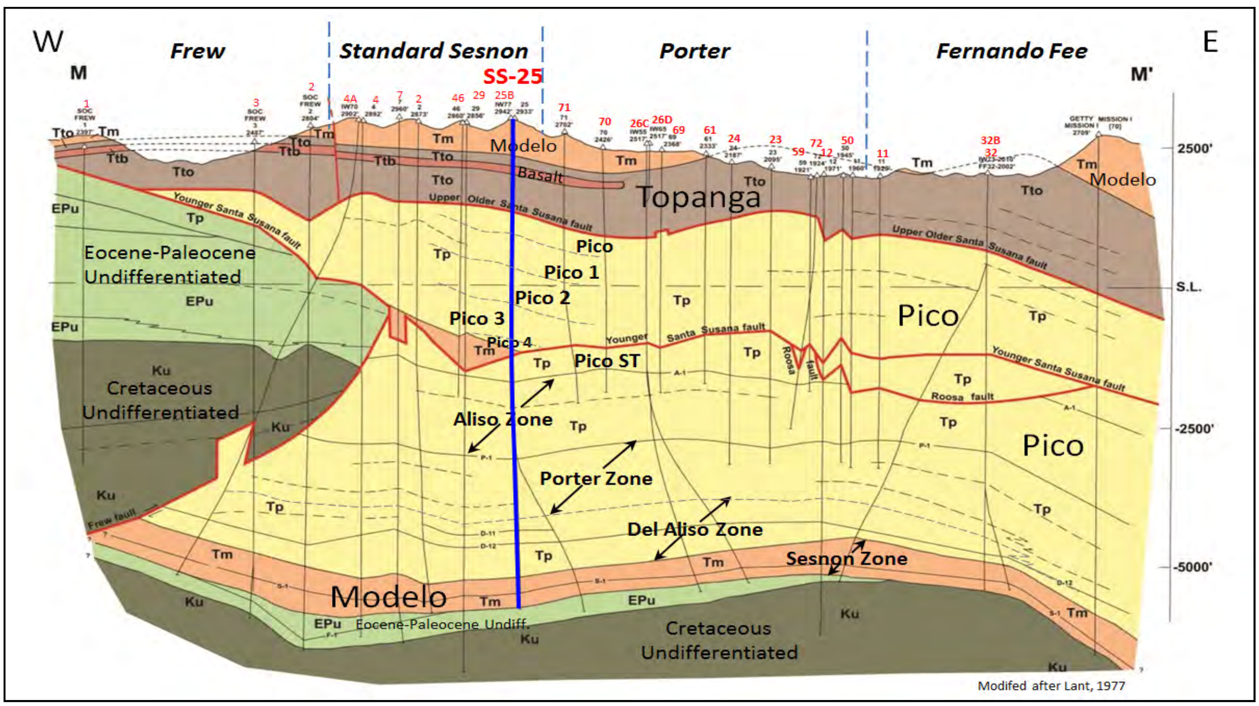


Figure 9. West-East cross-section across the Aliso Canyon oil field showing the location of the SS-25 with respect to the OSST and YSST thrust faults and the resultant stratigraphy. Note the thrusting of older Miocene Modelo and Topanga formations over the younger Pliocene Pico along the OSST and the YSST which thrusted Pico over Pico resulting in a thick Pico section of sands, claystones and clay.

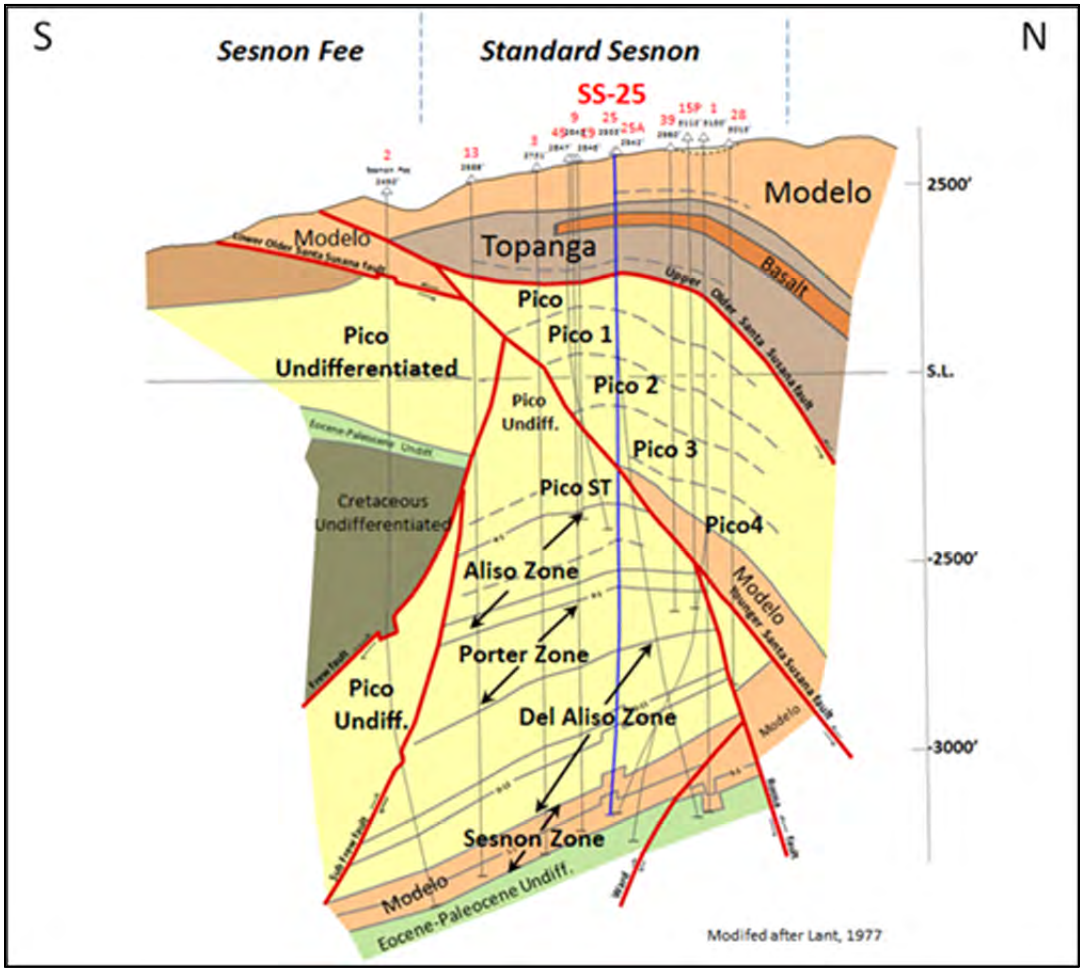


Figure 10. South-North cross-section across the Aliso Field showing the location of the SS-25. Note the steep dip angle of the YSST, and that formation dip angles above the YSST are to the north while formation dip angles below are to the south.

5.2.2 Subsurface Stratigraphy

Formations penetrated by the SS-25 wellbore consist of 1,615 ft of OSST overthrust Modelo and Toganga formations, 6,566 ft of the Pico formation and 567 ft of the YSST subthrust Modelo (Sesnon). Sediments are primarily young unconsolidated sediments of the Pliocene Pico Formation, composed of largely sands and claystone and clay.

The stratigraphic section present in the SS-25 wellbore is shown in the composite log in Figure 11. A well log comparison between SS-25 and P-39A is shown in Figure 12.

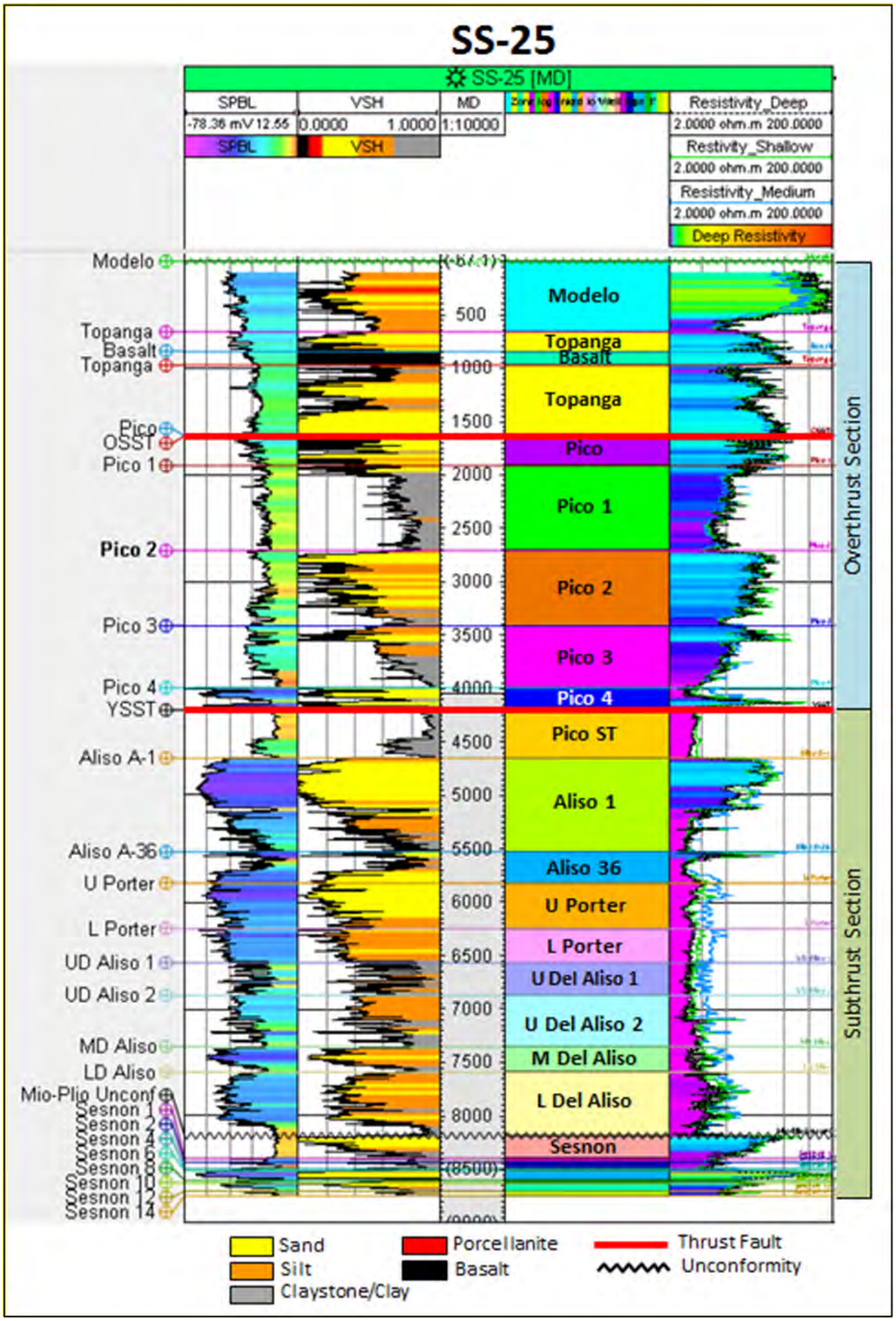


Figure 11. Composite Log of the SS-25, open-hole electric logs, stratigraphy, faults and VSH lithology interpretation for the SS-25.

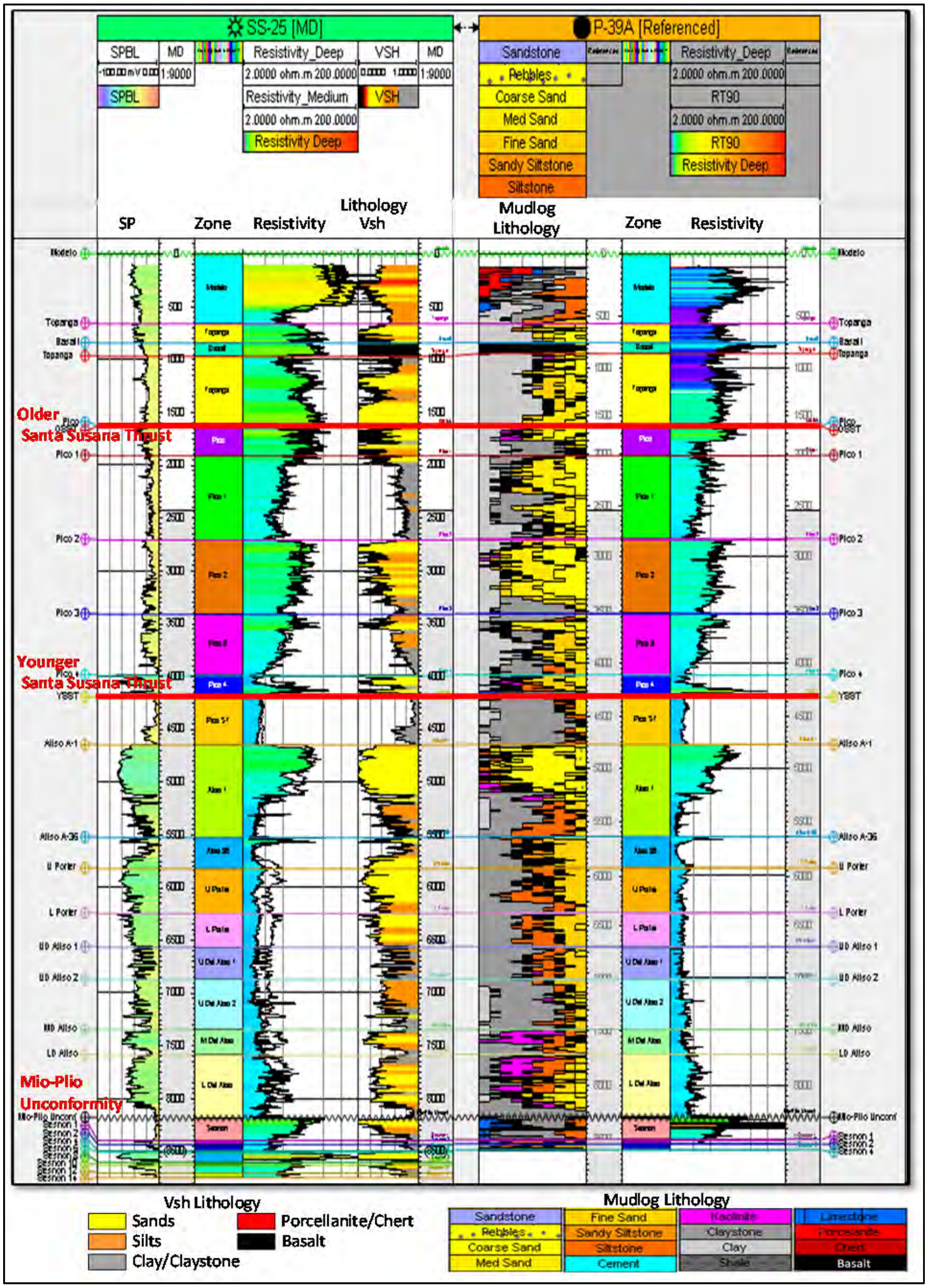


Figure 12. SS-25 and P-39A relief well log comparison. Formation tops have been flattened on the tops so that a direct comparison between the stratigraphy and lithology of the two wells can be evaluated. The P-39A surface location is approximately 1,600 ft from the surface location of the SS-25. At ~3,500 ft MD (~top Pico 3) in the P-39A relief well the wellbore is directly adjacent and tracks the SS-25 wellbore. Note the excellent correlations between the two wells and fault locations. The mudlog of the P-39A is also shown and provides an excellent source for lithology prediction for the SS-25 wellbore.

Table 1 shows the zone tops, formation tops, thicknesses, and lithologic descriptions for the SS-25 well, with more specific detail provided in Figure 13.

Table 1. SS-25 Geologic Description

Age	Formation	Zone	Geological Description	Top (MD-ft)	Base (MD-ft)	Thickness	Bed/Thrust Dip Angle
Middle Miocene	Modelo	Modelo	Interbedded porcellanite, silstones, sands, organic shales, and soft clays, tar-bearing, lost circulation area, possibly fractured	0	660	660	
	Topanga	Topanga	Slightly consolidated f-vf grained sand, some pebbles, interbedded with soft greenish blue gray clay	660	845	185	
		Topanga Basalt	Volcanic, amygdaloidal basalt,	845	969	124	
		Topanga	Unconsolidated sand, C-f grained , bluish gray to gray white sticky clay	969	1635	666	
		Older Santa Susana Thrust Fault		*1635*			15° NE
Upper Pliocene	Pico	Pico	Kaolinitic sand, c-m grained, soft, sticky claystone and clay	1635	1912	277	26° NE
		Pico 1	Unconsolidated sand, c-m grained, interbedded claystone	1912	2707	795	26° NE
		Pico 2	Massive unconsolidated sand, claystone	2707	3412	705	26° NE
		Pico 3	Unconsolidated sand, siltst, sticky clay	3412	3992	580	26° NE
		Pico 4	Unconsolidated kaolinitic sand, siltst	3992	4200	208	26° NE
		Young Santa Susana Thrust Fault		*4200*			55° N
	Pico	Pico ST	Claystone, minor siltstone	4200	4650	450	18° S-SW
		Aliso 1	Massive unconsolidated sand, kaolinite	4650	5527	877	18° S-SW
		Aliso 36	Claystone, siltstone, unconsol. sand	5527	5820	293	18° S-SW
		Upper Porter	Claystone, siltstone, unconsol. sand	5820	6245	425	16° SW
		Lower Porter	Sand, siltstone, claystone interbeds	6245	6566	321	18° S-SW
Lower Pliocene		Upper Del Aliso 1	Sand, siltstone, claystone interbeds	6566	6871	305	18° S-SW
		Upper Del Aliso 2	Claystone, minor siltstone and sand	6871	7350	479	18° S-SW
		Middle Del Aliso	Kaolinite, claystone, siltstone, sand	7350	7588	238	20° S-SW
		Lower Del Aliso	Kaolinite, siltstone, sand	7588	8182	594	18° S-SW
		Miocene - Pliocene Unconformity		*8182*			21° S-Sw
Middle Miocene	Modelo	Sesnon Cap Rock	Cap Rock, hard, limestone, claystone and shale	8182	8395	213	15° S-SW
		S1	Sand and siltstone interbeds	8395	8434	39	15° S-SW
		S2	Sand and siltstone interbeds	8434	8492	58	15° S-SW
		S4	Sand	8492	8509	17	15° S-SW
		S6	Sand	8509	8600	91	15° S-SW
		S8	Siltstone, sand and claystone	8600	8628	28	15° S-SW
		S10	Siltstone, sand and claystone	8628	8702	74	15° S-SW
		S12	Siltstone, sand and claystone	8702	8748	46	15° S-SW
		S14	Not penetrated	8748	8749	1	15° S-SW
		Total Well Depth		8749			

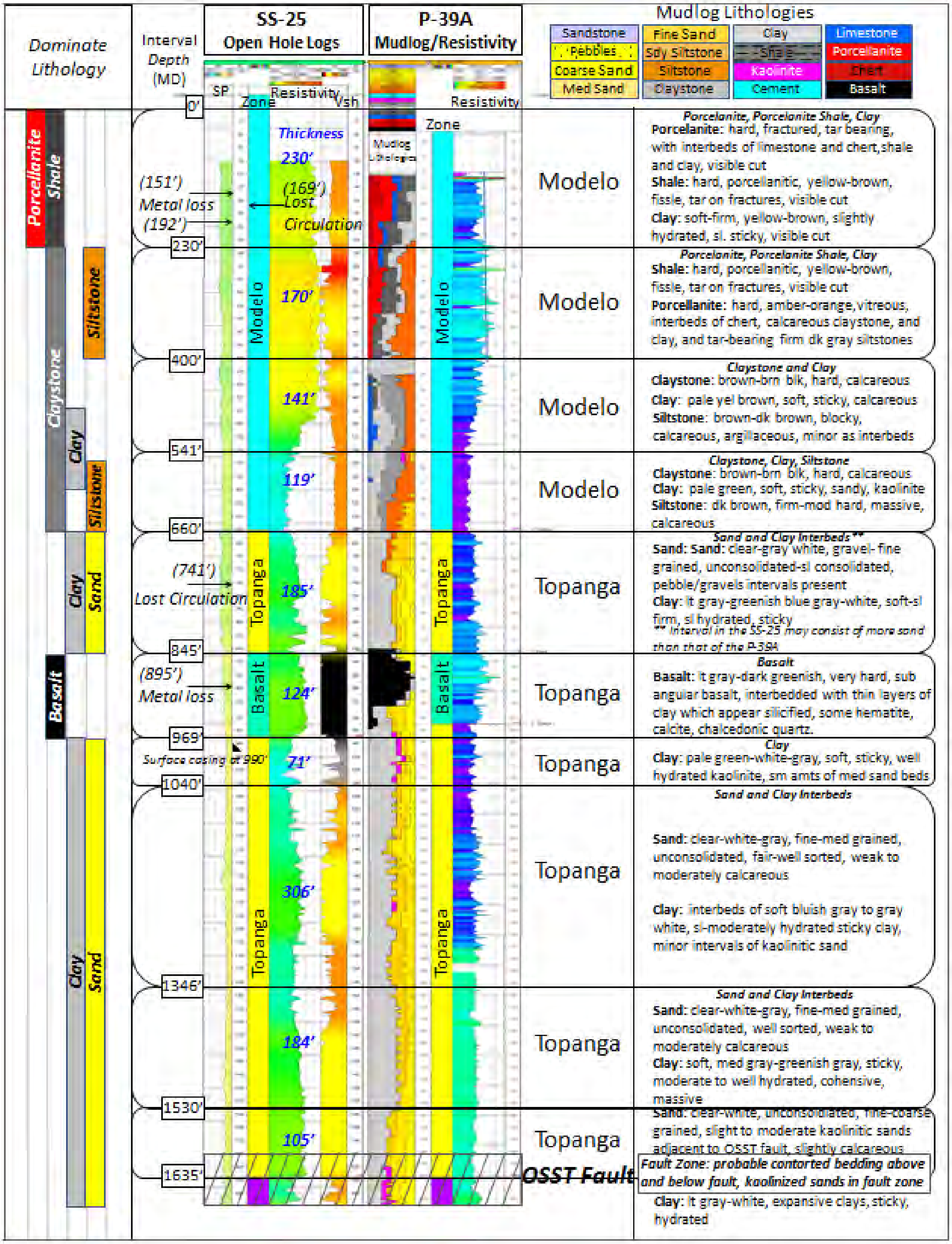


Figure 13. Detailed formation zone breakdown by lithology for SS-25 utilizing the P-39A mudlog data.

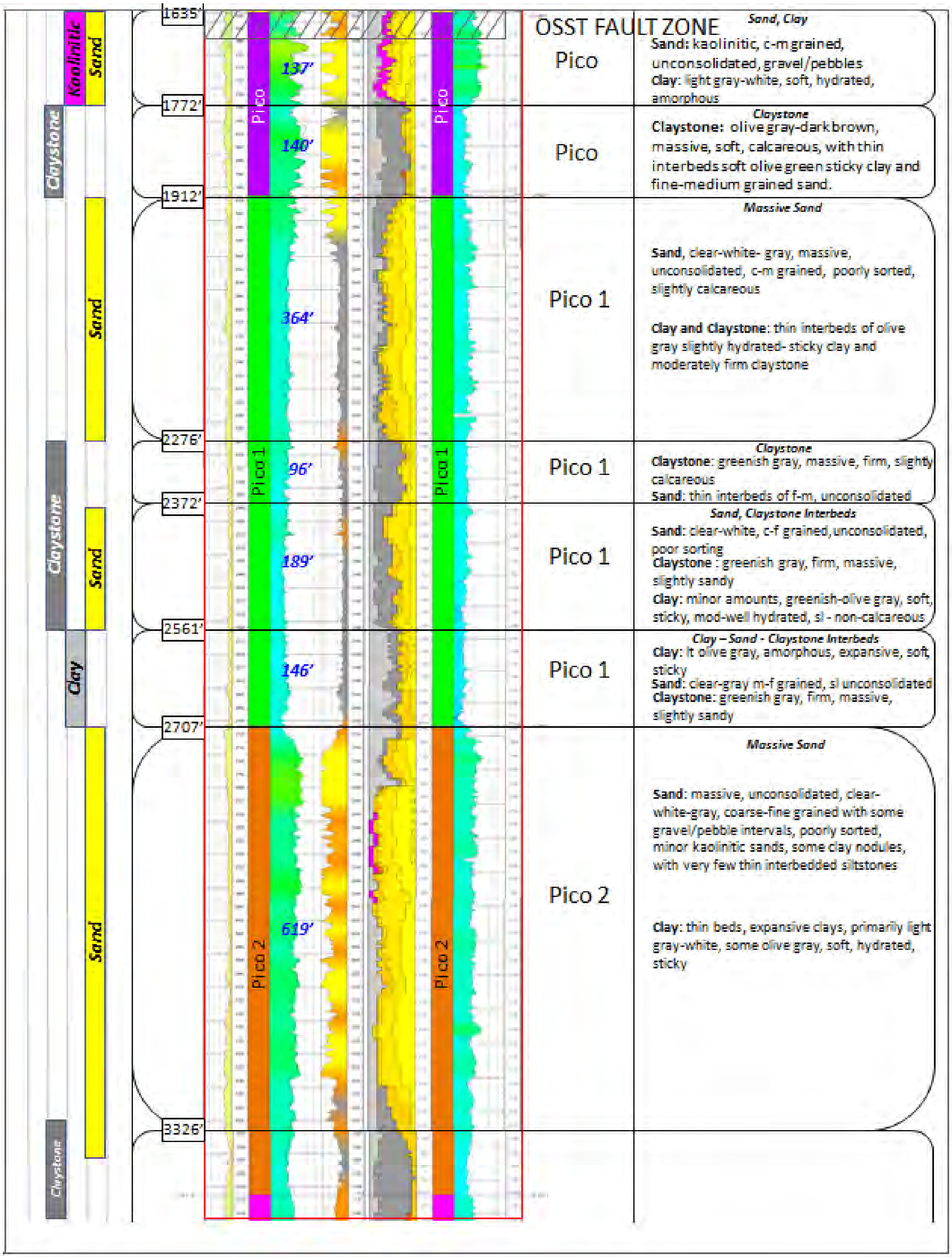

1635'
Kaolinitic
Sand
137'
Pico
Pico
OSST FAULT ZONE
Pico
Sand, Clay
Sand: kaolinitic, c-m grained, unconsolidated, gravel/pebbles
Clay: light gray-white, soft, hydrated, amorphous
1772'
Claystone
140'
Pico
Claystone
Claystone: olive gray-dark brown, massive, soft, calcareous, with thin interbeds soft olive green sticky clay and fine-medium grained sand.
1912'
Sand
364'
Pico 1
Massive Sand
Sand, clear-white- gray, massive, unconsolidated, c-m grained, poorly sorted, slightly calcareous
Clay and Claystone: thin interbeds of olive gray slightly hydrated- sticky clay and moderately firm claystone
2276'
Pico 1
Pico 1
96'
Pico 1
Claystone
Claystone: greenish gray, massive, firm, slightly calcareous
Sand: thin interbeds of f-m, unconsolidated
2372'
Claystone
Sand
189'
Pico 1
Sand, Claystone Interbeds
Sand: clear-white, c-f grained, unconsolidated, poor sorting
Claystone : greenish gray, firm, massive, slightly sandy
Clay: minor amounts, greenish-olive gray, soft, sticky, mod-well hydrated, sl - non-calcareous
2561'
Clay
146'
Pico 1
Clay – Sand - Claystone Interbeds
Clay: lt olive gray, amorphous, expansive, soft, sticky
Sand: clear-gray m-f grained, sl unconsolidated
Claystone: greenish gray, firm, massive, slightly sandy
2707'
Sand
619'
Pico 2
Pico 2
Pico 2
Massive Sand
Sand: massive, unconsolidated, clear-white-gray, coarse-fine grained with some gravel/pebble intervals, poorly sorted, minor kaolinitic sands, some clay nodules, with very few thin interbedded siltstones
Clay: thin beds, expansive clays, primarily light gray-white, some olive gray, soft, hydrated, sticky
3326'
Claystone

Figure 13a

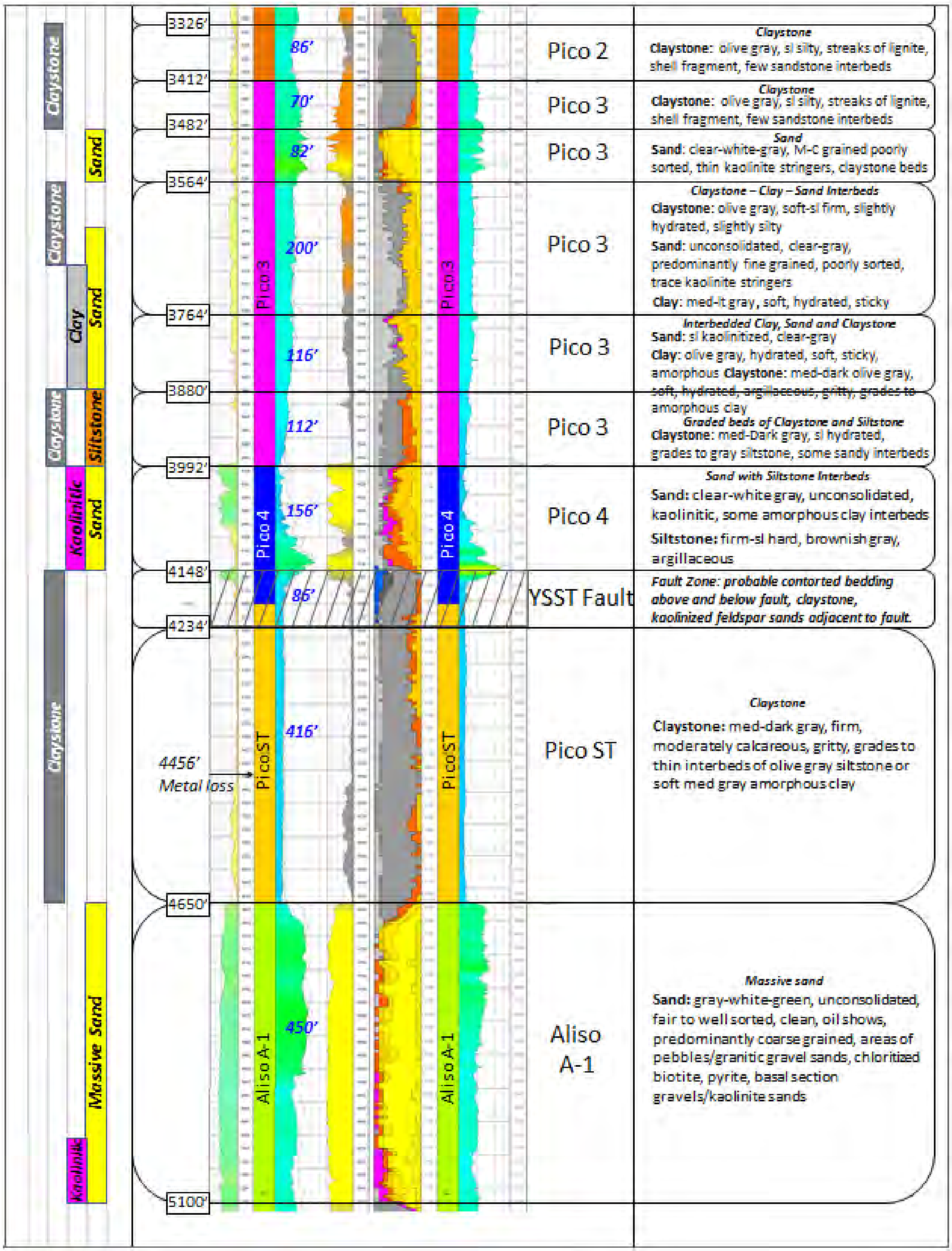

Claystone
Sand
Claystone
Clay
Sand
Claystone
Siltstone
Kaolinitic
Sand
Claystone
Massive Sand
Kaolinitic
3326'
3412'
3482'
3564'
3764'
3880'
3992'
4148'
4234'
4650'
5100'
86'
70'
82'
200'
116'
112'
156'
86'
416'
450'
4456'
Metal loss
Pico 3
Pico 4
Pico ST
Aliso A-1
Pico 2
Pico 3
Pico 3
Pico 3
Pico 3
Pico 3
Pico 4
YSST Fault
Pico ST
Aliso A-1
Claystone
Claystone: olive gray, sl silty, streaks of lignite, shell fragment, few sandstone interbeds
Claystone
Claystone: olive gray, sl silty, streaks of lignite, shell fragment, few sandstone interbeds
Sand
Sand: clear-white-gray, M-C grained poorly sorted, thin kaolinite stringers, claystone beds
Claystone – Clay – Sand Interbeds
Claystone: olive gray, soft-sl firm, slightly hydrated, slightly silty
Sand: unconsolidated, clear-gray, predominantly fine grained, poorly sorted, trace kaolinite stringers
Clay: med-lt gray, soft, hydrated, sticky
Interbedded Clay, Sand and Claystone
Sand: sl kaolinitized, clear-gray
Clay: olive gray, hydrated, soft, sticky, amorphous Claystone: med-dark olive gray, soft, hydrated, argillaceous, gritty, grades to amorphous clay
Graded beds of Claystone and Siltstone
Claystone: med-Dark gray, sl hydrated, grades to gray siltstone, some sandy interbeds
Sand with Siltstone Interbeds
Sand: clear-white gray, unconsolidated, kaolinitic, some amorphous clay interbeds
Siltstone: firm-sl hard, brownish gray, argillaceous
Fault Zone: probable contorted bedding above and below fault, claystone, kaolinized feldspar sands adjacent to fault.
Claystone
Claystone: med-dark gray, firm, moderately calcareous, gritty, grades to thin interbeds of olive gray siltstone or soft med gray amorphous clay
Massive sand
Sand: gray-white-green, unconsolidated, fair to well sorted, clean, oil shows, predominantly coarse grained, areas of pebbles/granitic gravel sands, chloritized biotite, pyrite, basal section gravels/kaolinite sands

Figure 13b

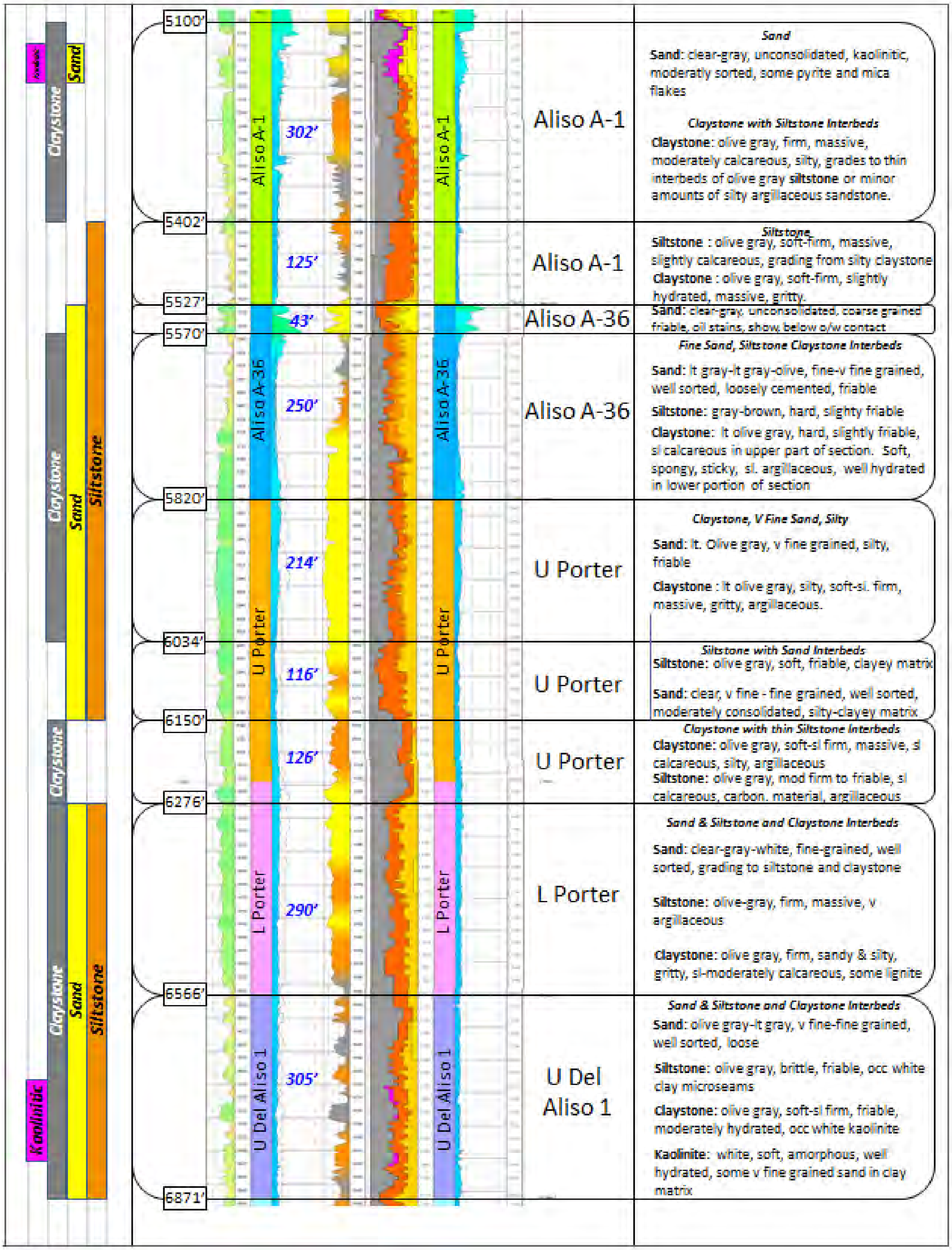
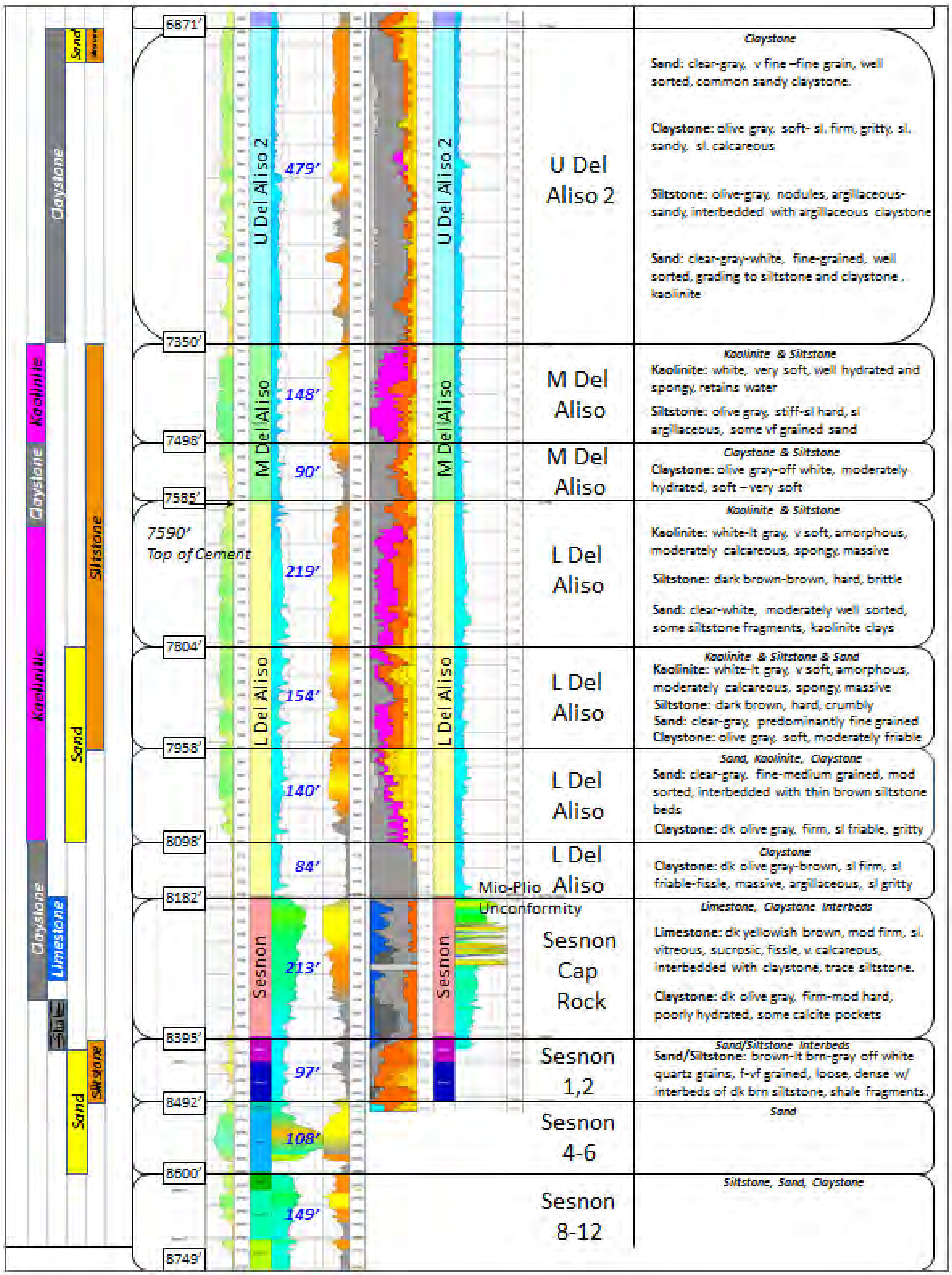

Claystone
Sand
Siltstone
Kaolinitic
5100'
5402'
5527'
5570'
5820'
6034'
6150'
6276'
6566'
6871'
Aliso A-1
302'
125'
43'
Aliso A-36
250'
U Porter
214'
116'
126'
L Porter
290'
U Del Aliso 1
305'
Aliso A-1
Aliso A-1
Aliso A-36
Aliso A-36
U Porter
U Porter
U Porter
L Porter
U Del Aliso 1
Sand
Sand: clear-gray, unconsolidated, kaolinitic, moderatly sorted, some pyrite and mica flakes
Claystone with Siltstone Interbeds
Claystone: olive gray, firm, massive, moderately calcareous, silty, grades to thin interbeds of olive gray siltstone or minor amounts of silty argillaceous sandstone.
Siltstone
Siltstone : olive gray, soft-firm, massive, slightly calcareous, grading from silty claystone
Claystone : olive gray, soft-firm, slightly hydrated, massive, gritty.
Sand: clear-gray, unconsolidated, coarse grained friable, oil stains, show below o/w contact
Fine Sand, Siltstone Claystone Interbeds
Sand: lt gray-lt gray-olive, fine-v fine grained, well sorted, loosely cemented, friable
Siltstone: gray-brown, hard, slighty friable
Claystone: lt olive gray, hard, slightly friable, sl calcareous in upper part of section. Soft, spongy, sticky, sl. argillaceous, well hydrated in lower portion of section
Claystone, V Fine Sand, Silty
Sand: lt. Olive gray, v fine grained, silty, friable
Claystone : lt olive gray, silty, soft-sl. firm, massive, gritty, argillaceous.
Siltstone with Sand Interbeds
Siltstone: olive gray, soft, friable, clayey matrix
Sand: clear, v fine - fine grained, well sorted, moderately consolidated, silty-clayey matrix
Claystone with thin Siltstone Interbeds
Claystone: olive gray, soft-sl firm, massive, sl calcareous, silty, argillaceous
Siltstone: olive gray, mod firm to friable, sl calcareous, carbon. material, argillaceous
Sand & Siltstone and Claystone Interbeds
Sand: clear-gray-white, fine-grained, well sorted, grading to siltstone and claystone
Siltstone: olive-gray, firm, massive, v argillaceous
Claystone: olive gray, firm, sandy & silty, gritty, sl-moderately calcareous, some lignite
Sand & Siltstone and Claystone Interbeds
Sand: olive gray-lt gray, v fine-fine grained, well sorted, loose
Siltstone: olive gray, brittle, friable, occ white clay microseams
Claystone: olive gray, soft-sl firm, friable, moderately hydrated, occ white kaolinite
Kaolinite: white, soft, amorphous, well hydrated, some v fine grained sand in clay matrix

Figure 13c



Sand
Claystone
Kaolinite
Claystone
Siltstone
Kaolinitic
Sand
Claystone
Limestone
Shale
Sand
Siltstone
6871'
7350'
7498'
7585'
7590' Top of Cement
7804'
7958'
8098'
8182'
8395'
8492'
8600'
8749'
U Del Aliso 2
479'
M Del Aliso
148'
90'
219'
L Del Aliso
154'
140'
84'
Sesnon
213'
97'
108'
149'
U Del Aliso 2
M Del Aliso
M Del Aliso
L Del Aliso
L Del Aliso
L Del Aliso
L Del Aliso
Mio-Plio Unconformity
Sesnon Cap Rock
Sesnon 1,2
Sesnon 4-6
Sesnon 8-12
Claystone
Sand: clear-gray, v fine –fine grain, well sorted, common sandy claystone.
Claystone: olive gray, soft- sl. firm, gritty, sl. sandy, sl. calcareous
Siltstone: olive-gray, nodules, argillaceous-sandy, interbedded with argillaceous claystone
Sand: clear-gray-white, fine-grained, well sorted, grading to siltstone and claystone, kaolinite
Kaolinite & Siltstone
Kaolinite: white, very soft, well hydrated and spongy, retains water
Siltstone: olive gray, stiff-sl hard, sl argillaceous, some vf grained sand
Claystone & Siltstone
Claystone: olive gray-off white, moderately hydrated, soft – very soft
Kaolinite & Siltstone
Kaolinite: white-lt gray, v soft, amorphous, moderately calcareous, spongy, massive
Siltstone: dark brown-brown, hard, brittle
Sand: clear-white, moderately well sorted, some siltstone fragments, kaolinite clays
Kaolinite & Siltstone & Sand
Kaolinite: white-lt gray, v soft, amorphous, moderately calcareous, spongy, massive
Siltstone: dark brown, hard, crumbly
Sand: clear-gray, predominantly fine grained
Claystone: olive gray, soft, moderately friable
Sand, Kaolinite, Claystone
Sand: clear-gray, fine-medium grained, mod sorted, interbedded with thin brown siltstone beds
Claystone: dk olive gray, firm, sl friable, gritty
Claystone
Claystone: dk olive gray-brown, sl firm, sl friable-fissle, massive, argillaceous, sl gritty
Limestone, Claystone Interbeds
Limestone: dk yellowish brown, mod firm, sl. vitreous, sucrosic, fissle, v. calcareous, interbedded with claystone, trace siltstone.
Claystone: dk olive gray, firm-mod hard, poorly hydrated, some calcite pockets
Sand/Siltstone Interbeds
Sand/Siltstone: brown-lt brn-gray off white quartz grains, f-vf grained, loose, dense w/ interbeds of dk brn siltstone, shale fragments.
Sand
Siltstone, Sand, Claystone

Figure 13d

5.2.3 SS-25 Other Characterizing Elements

Other key characteristics of the SS-25 well are described below.

- **Lost Circulation Potential**
  Lost circulation has been observed in a number of wells in the overthrust Modelo and Topanga formations. Lost circulation in the SS-25 occurred at 169 ft in the Modelo, at 741 ft and 990 ft in the Topanga.

- **Hydrocarbon Bearing Zones**
  Tar is present in the Middle Miocene Modelo as observed in mudlogs and surface outcrops in Aliso Canyon.

  The Upper Pliocene Aliso zone between 4,650 and 5,820 ft is an active oil producing zone and is actively being water flooded. Formation tests in the SS-25 resulted in hydrocarbon shows in the Aliso A-1 zone at: 4,661-4,781 ft, 4,725-4,860 ft, and 4,795-4,910 ft.

  The Middle Miocene Sesnon zone from 8,395 ft to TD is a gas storage reservoir.

- **Swelling Clays**
  Expansive clays are present throughout the stratigraphic section penetrated by the SS-25. Descriptions in the P-39A mudlog include "hydrated, sticky, fluffy" with respect to clay and claystone sections in the report. X-ray diffraction data was located for the Sesnon (Modelo) in the P-42A and FF32-A wells which identified the expansive clay smectite along with non-swelling clays of illite and kaolinite in of those samples. X-Ray diffraction data was not found for the other formation.

- **Fault Zones**
  The area above and below the OSST and YSST thrust faults would be expected to be broken with contorted beds. Sands adjacent to both of these faults are kaolinitic suggesting alteration of the feldspars due to introduction of fluids along the fault planes. The YSST is a sealed fault and is trap for hydrocarbons below it and not expected to be a zone of lost circulation.

- **Bed / Fault Dip Angles**
  Dip angles for the formations/zones were computed from maps for the SS-25. They are identified previously in Table 1. Beds above the YSST dip to the north, and to the south below the thrust.

- **Formation Water Salinities**
  Water Salinity calculations were computed from the electric logs for the entire depths penetrated in the two wells adjacent to the SS-25, the SS-25A and SS-25B. No salinities less than 1000 ppm were observed in either well, hence there is no indication of the present of any fresh water zones. Salinities decrease up hole as depicted in Figure 14.

A structural cross section comparing the SS-25, SS-25A and SS-25B wells is shown in Figure 15. A similar cross section showing the SS-25, SS-25B wells and the P-39A relief well is shown in Figure 16.

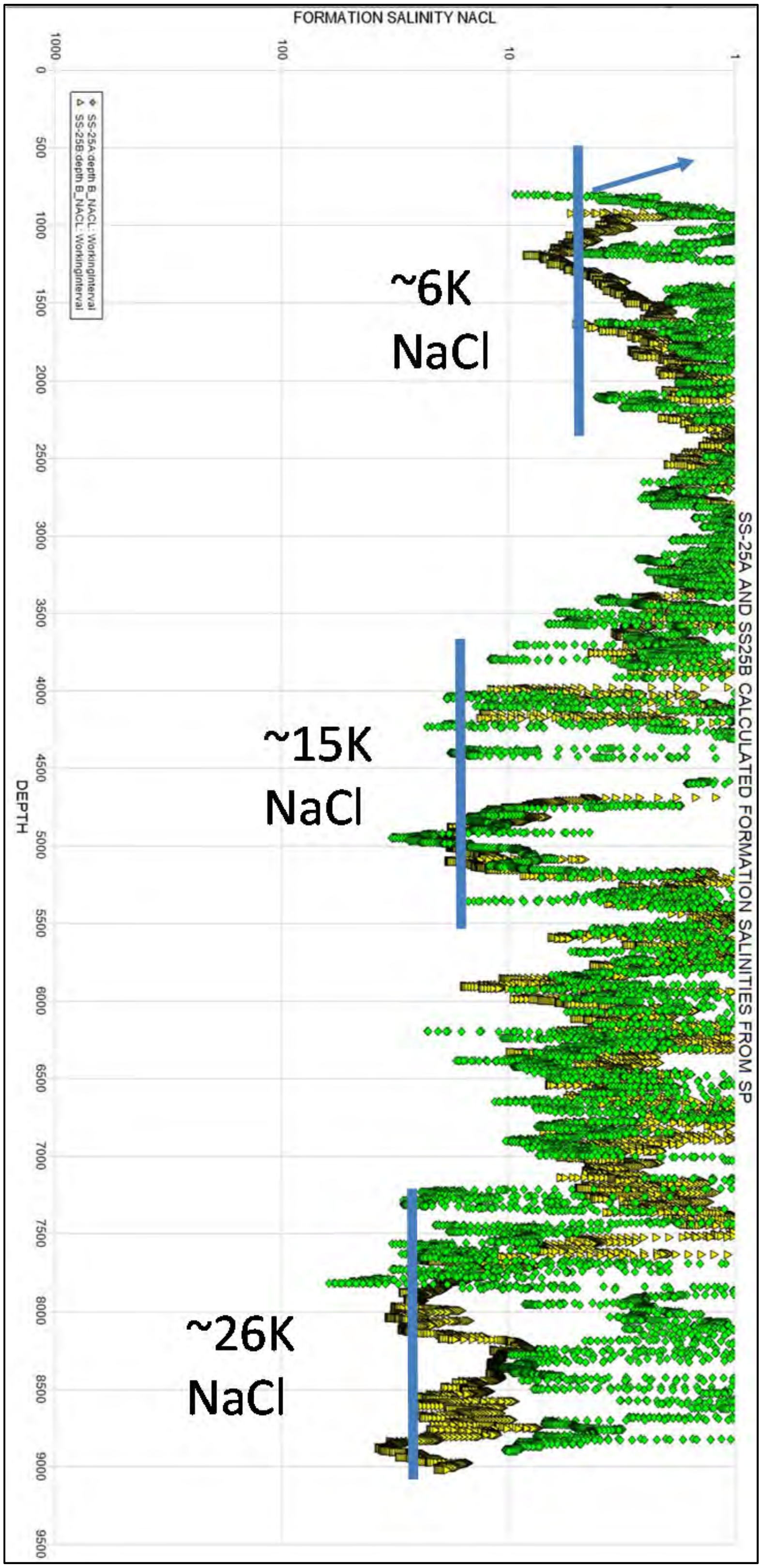


Figure 14. SS-25A and SS-25B Computed Water Salinities

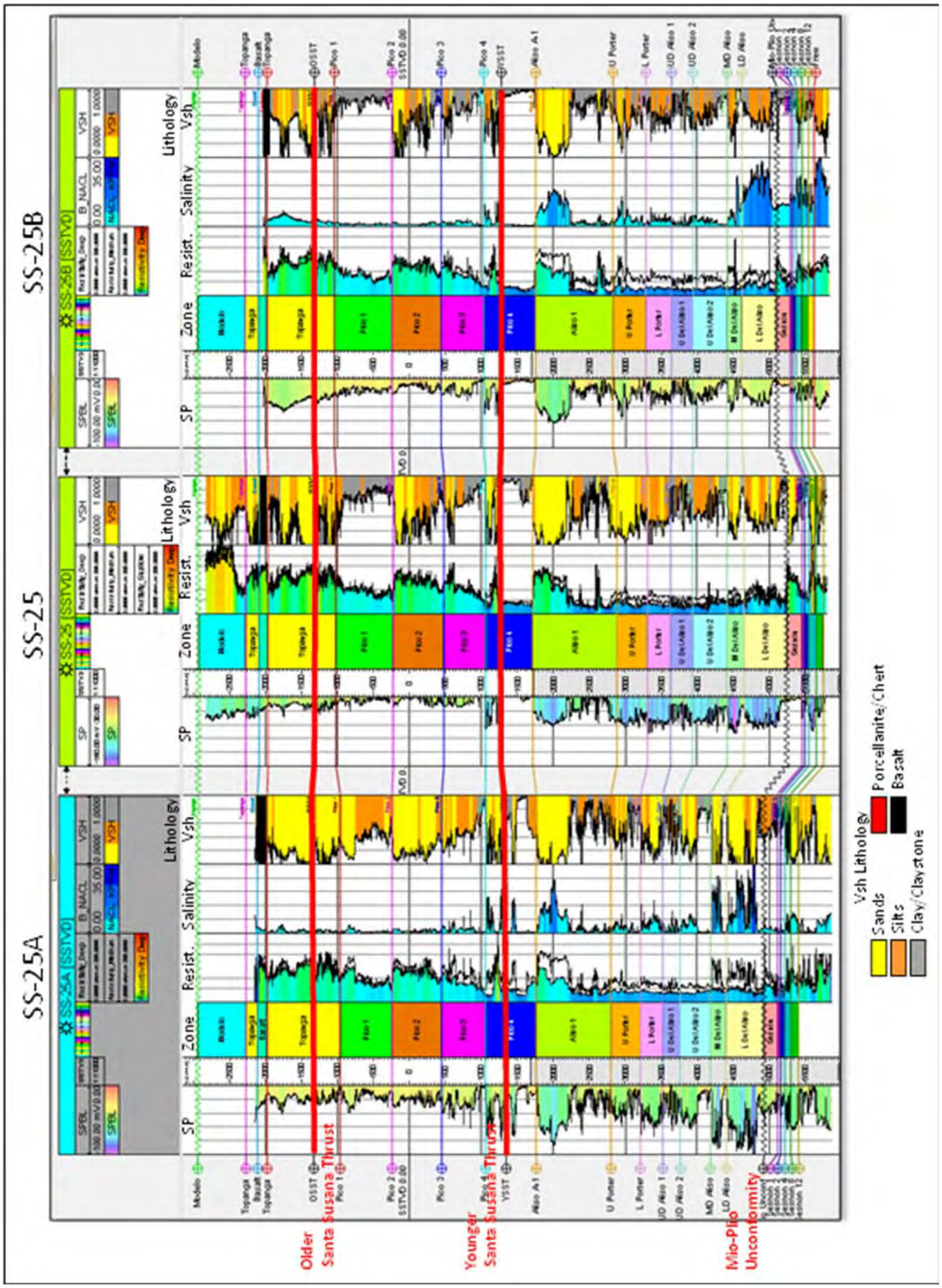


Figure 15. Structural west-east electric log cross-section which includes the SS-25 and analog adjacent wells SS-25 and SS-25B.

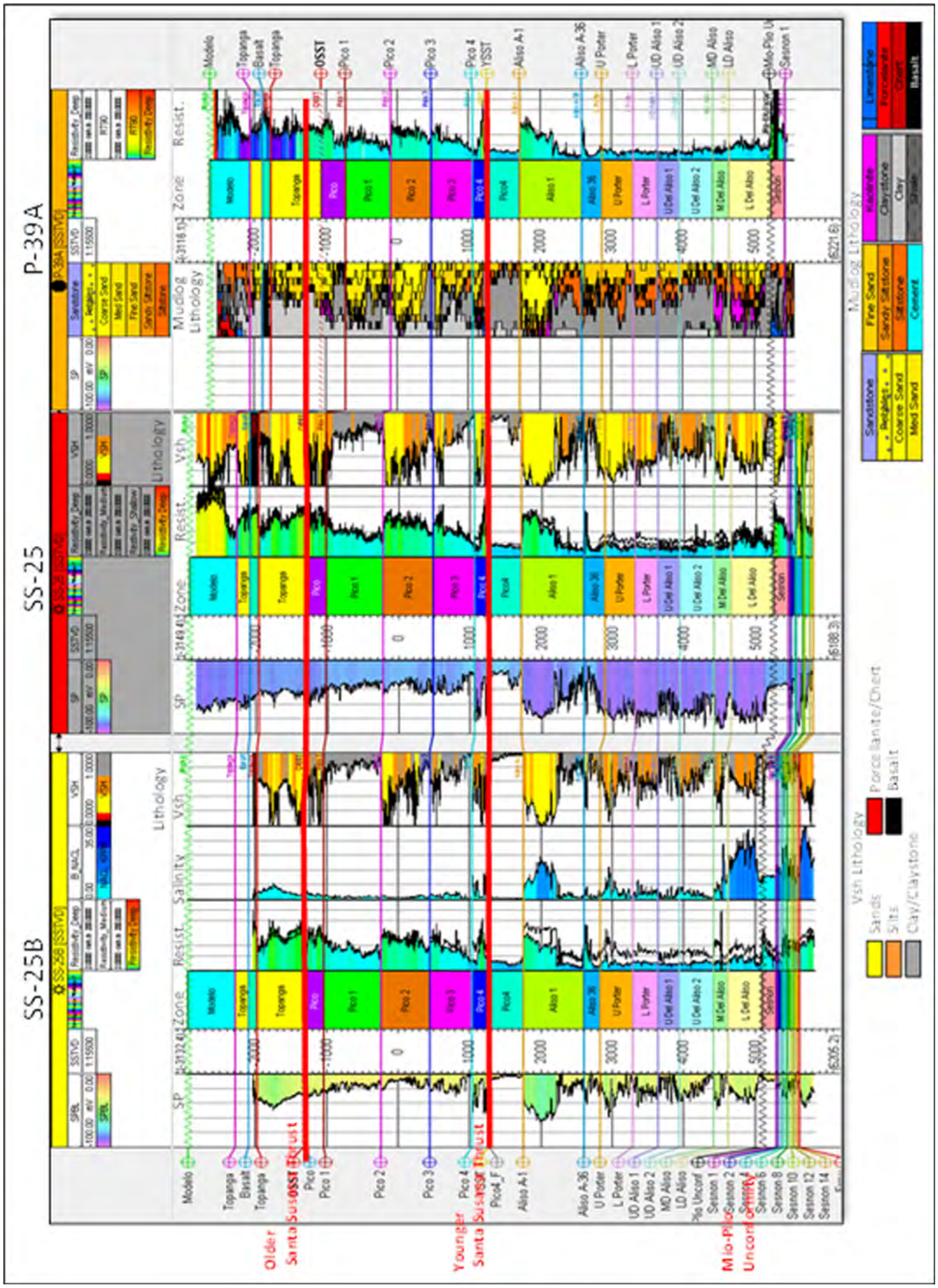


Figure 16. Structural west-east electric log cross section comparison for the SS-25B, SS-25 and P-39A wells.

5.3 Pore Pressure / Fracture Gradient and Geothermal Gradient

The estimated pore pressure and formation fracture gradient for the SS-25 well is shown in Figure 17. The pore pressure is nominally hydrostatic (8.33 ppg), however formation pressure tests while drilling indicate sub-hydrostatic pressures around 4,700 ft. The original Sesnon reservoir BHP from the Kunitomi[i] report was 3,600 psi at 8,300 ft TVD for an EMW of 8.34 ppg. The estimated BHP at the time of the well kill was 1190 psi at 8,475 ft TVD for an EMW of 2.7 ppg. This was based on Well SS-5 as reported in the Well P-39A relief well kill procedure. The lowest operating reservoir pressure is 1,000 psi. There is limited available fracture gradient data. The fracture gradient in the reservoir section is reported to be between 0.8 and 0.9 psi/ft, and there was some data provided in the P-39A kill analysis report, and the drilling reports. The fracture gradient is assumed to be essentially zero above ~900 ft based on the lost circulation issues reported in the SS-25 wells. No mud weights were listed in the SS-25 drilling records above 2,700 ft.

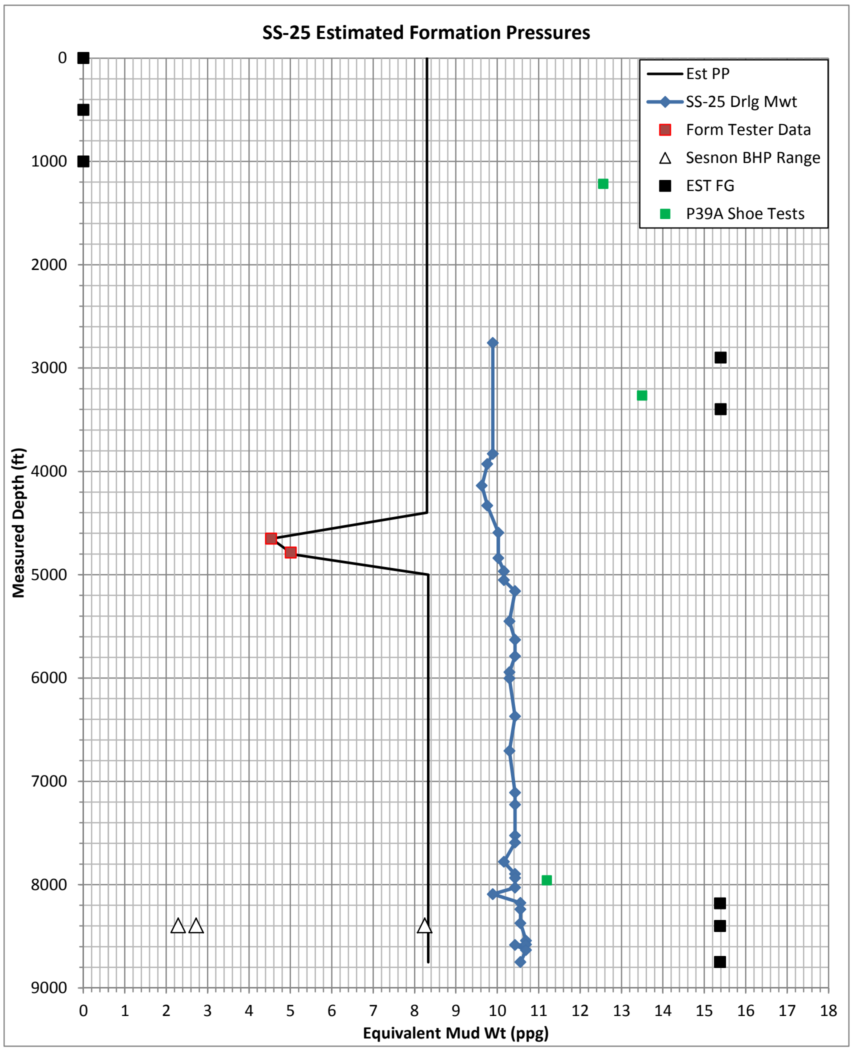
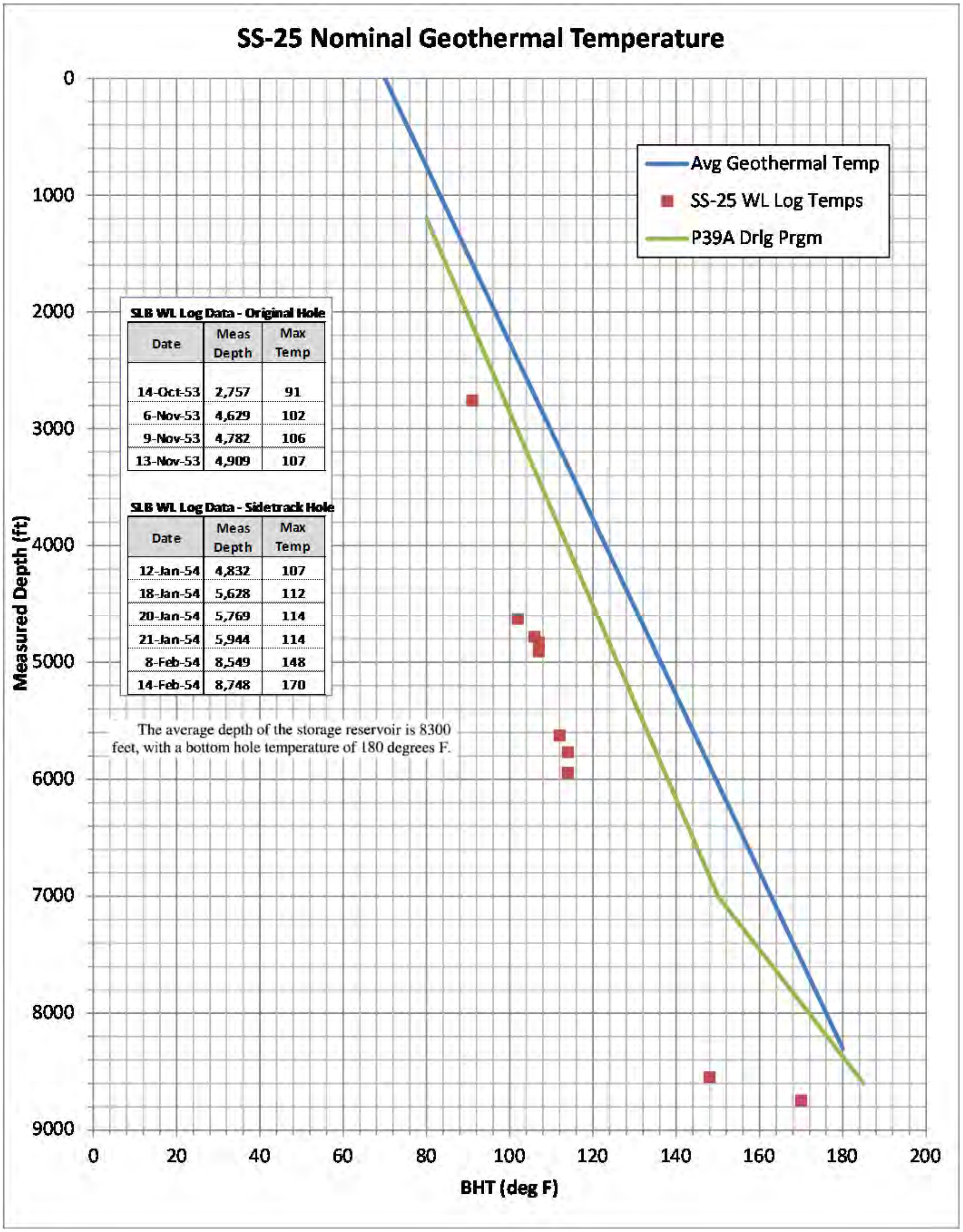


Figure 17. SS-25 Estimated Formation Pressures

[i] Natural Gas Storage Operations and Geology of the Aliso Canyon Field, Los Angeles Co., California, D.S. Kunitomi, T. Schrader, (not dated).

Available data on the nominal, undisturbed geothermal temperature data for SS-25 is shown in Figure 18. The data comes from the original 1954 wireline logs, and information provided in the P-39A drilling and completion program. The average geothermal gradient is based on the Kunitomi report.



SLB WL Log Data - Original Hole

Date	Meas Depth	Max Temp
14-Oct-53	2,757	91
6-Nov-53	4,629	102
9-Nov-53	4,782	106
13-Nov-53	4,909	107

SLB WL Log Data - Sidetrack Hole

Date	Meas Depth	Max Temp
12-Jan-54	4,832	107
18-Jan-54	5,628	112
20-Jan-54	5,769	114
21-Jan-54	5,944	114
8-Feb-54	8,549	148
14-Feb-54	8,748	170

Figure 18. SS-25 Geothermal Temperature Plot

5.4 SS-25 Analog Well Data Summary

The four analog wells shown in Table 2 were reviewed in order to determine what kind of issues occurred during drilling, in order to understand the kind of hole problems might impact the extraction operations on SS-25. The SS-25A and B wells were selected for their proximity. The SS-5 well was selected because it was listed as an analog well for the relief well planning, and the P-39A relief well because it was the most recent well with the best data. The analog well data is summarized below, and additional details for each well can be found in the Appendices.

Table 2. Analog Well Listing

Well	Spud	GLE	TD-MD	TD-TVD	API No.	Lat	Long
SS-5	2-Feb-45	2651.38	8,700	~8,700	037-00758	34.3138098	-118.5664
SS-25	1-Oct-53	2927	8,749	8,733	037-00776	34.31508291	-118.5640
SS-25A	2-Nov-72	2927	8,917	8,819	037-21322	34.3150725	-118.5641
SS-25B	13-Jan-73	2927	9,030	8,784	037-21323	34.31500	-118.5642
P-39A	4-Dec-15	2602	8,623	8,175	037-30471	34.31257	-118.5604

Figure 19 shows the surface locations of the analog wells relative to the SS-25 location, while Figure 20 compares the plan view directional profiles for the three SS-25 wells and the P-39A well. Table 3 shows the formation tops for the SS-25 A and B wells, and for P-39A.

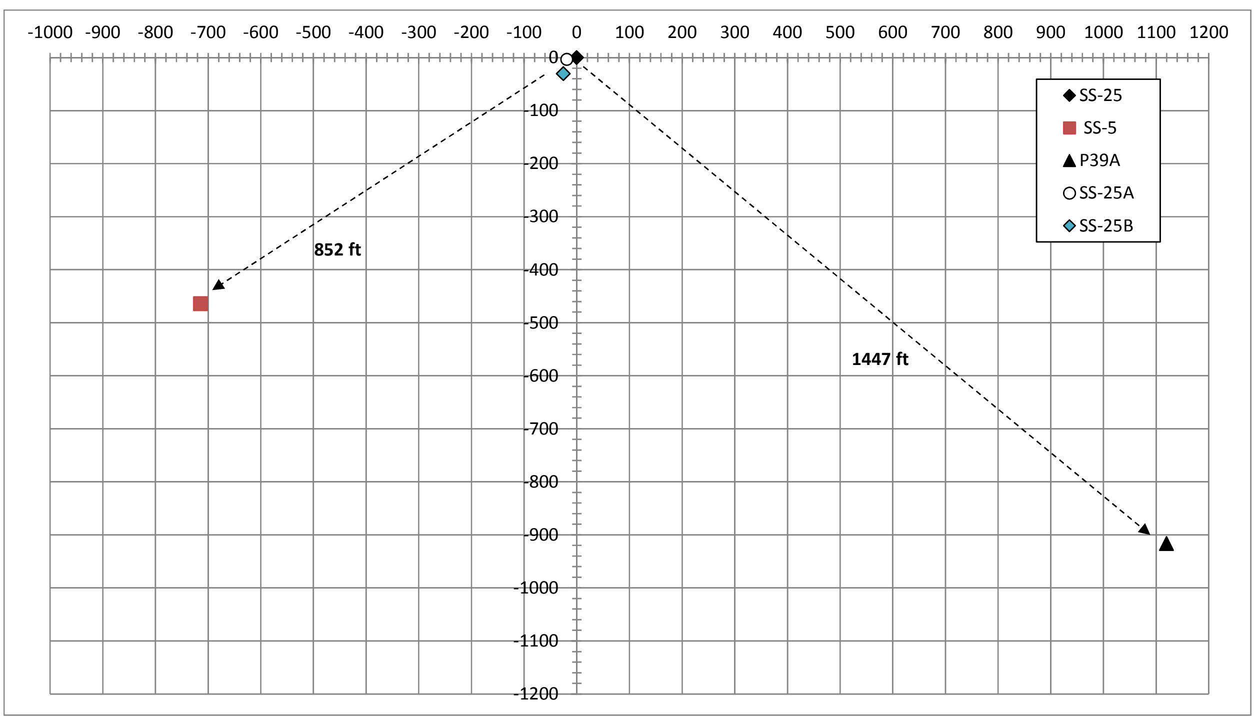


Figure 19. Analog Well Surface Location Comparison

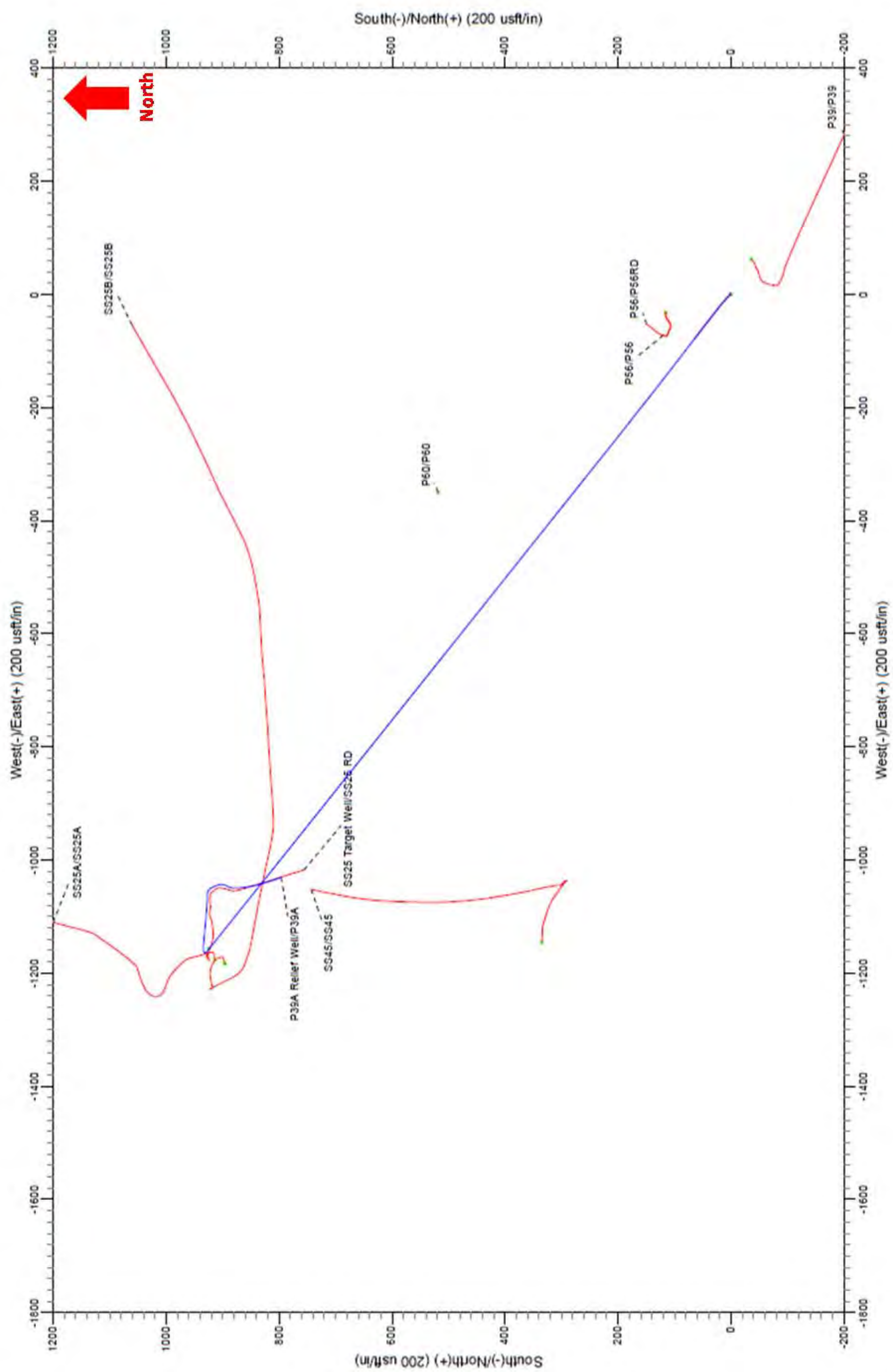


Figure 20. Analog Wells Directional Plan View Comparison

The correlative stratigraphic tops of the adjacent wells to the SS-25, wells SS-25A, SS-25B and Relief Well P-39A are provided in Table 3.

Table 3. SS-25A, SS-25B, P-39A Formation Tops

			SS-25A MD		SS-25B MD		P39A MD	
Age	**Formation**	**Zone**	**Top**	**Base**	**Top**	**Base**	**Top**	**Base**
Middle Miocene	**Modelo**	Modelo	0	670	0	658	0	560
	Topanga	Topanga	670	841	658	845	560	735
		Topanga Basalt	841	965	845	965	735	850
		Topanga	965	1614	965	1619	850	1602
		Old Santa Susana Thrust Fault	*1614*		*1619*		*1602*	
Upper Pliocene	**Pico**	Pico	1614	1979	1619	1900	1602	2011
		Pico 1	1979	2703	1900	2700	2011	2835
		Pico 2	2703	3394	2700	3385	2835	3522
		Pico 3	3394	4000	3385	3977	3522	4110
		Pico 4	4000	4425	3977	4208	4110	4306
		Young Santa Susana Thrust Fault	*4425*		*4208*		*4306*	
	Pico	Pico ST	4425	4708	4208	4696	4306	4774
		Aliso 1	4708	5529	4696	5547	4774	5644
		Aliso 36	5529	5768	5547	5775	5644	5926
		Upper Porter	5768	6188	5775	6250	5926	6364
		Lower Porter	6188	6506	6250	6633	6364	6702
Lower Pliocene		Upper Del Aliso 1	6506	6754	6633	6960	6702	7010
		Upper Del Aliso 2	6754	7183	6960	7512	7010	7479
		Middle Del Aliso	7183	7410	7512	7733	7479	7708
		Lower Del Aliso	7410	7945	7733	8250	7708	8293
		Miocene - Pliocene Unconformity	*7945*		*8250*		*8293*	
Middle Miocene	**Modelo**	Sesnon Cap Rock	7945	8134	8250	8448	8293	8513
		S1	8134	8180	8448	8483	8513	8556
		S2	8180	8240	8483	8534	8556	8607
		S4	8240	8272	8534	8583	8607	8623
		S6	8272	8326	8583	8624		
		S8	8326	8384	8624	8678		
		S10	8384	8436	8678	8716		
		S12	8436	8484	8716	8758		
		S14	8484	8674	8758	8798		
Eocene	**Frew**	Frew	8674	8905	8798	9030		
		Total Well Depth	8905		9030		8623	

A summary of the downhole related problems that occurred in the analog wells and the equivalent depth in SS-25 is shown in Table 4.

Table 4. Analog Well Downhole Problems Summary

Well Name	Comments	Measured Depth	Formation	Equiv. SS-25 MD
SS-25A 1972	Lost circulation	67 ft	Modelo	66 ft
	Lost circulation	371 ft	Modelo	365 ft
	Drilled without returns	371-779 ft	Modelo-Topanga	365-777 ft
	Lost circulation drilling with aerated mud	8,297 ft	Sesnon 6	8,551 ft
	Drilled with no to full returns with aerated mud, lost 800 bbls	8,297-8,456 ft	Sesnon 6,8,12	8,551-8,717 ft
SS-25B 1972	Stuck pipe drilling with air	100 ft	Modelo	101 ft
	Lost circulation drilling with mid	330 ft	Modelo	331 ft
	Drilled without returns	330-900 ft	Modelo-Topanga	331-901 ft
	Cement 13-3/8" without returns	900 ft	Topanga-Basalt	901 ft
	Lost circulation, lost 830 bbls	5,449 ft	Aliso A-1	5426 ft
	Stuck pipe	5,915 ft	U Porter	5,945 ft
	Twist off, lost circulation while fishing - lost 350 bbls. ST around fish	7,984 ft	L Del Aliso	7,876 ft
	Lost circulation - 300 bbls, drill with partial returns	7,905 ft	L Del Aliso	7,786 ft
	Twist-off	7,956 ft	L Del Aliso	7,844 ft
P-39A 2015	Partial lost returns	170 ft	Modelo	200 ft
	Complete lost circulation (set 2 cmt plugs)	362 ft	Modelo	427 ft
	Tight hole – 10-15k drag	2,101-2,095 ft 2,050-1,997 ft 1,935, 2,126 ft 2,225 ft	Pico Pico 2-Pico Pico, Pico 1 Pico 1	1,999-1,993 ft 1,949-1,903 ft 1,861,2,023 ft 2,118 ft
	Tight hole – 15k drag	2,929 ft	Pico 2	2,803 ft
	High rotating torque	7,040 ft	U Del Aliso 2	6,901 ft
S-5	No hole problems were reported	---	---	---

A comparison of the mud weights used on the analog wells, as well as the depths at which there were lost circulation or mechanical (stuck pipe) problems is shown in Figure 21.

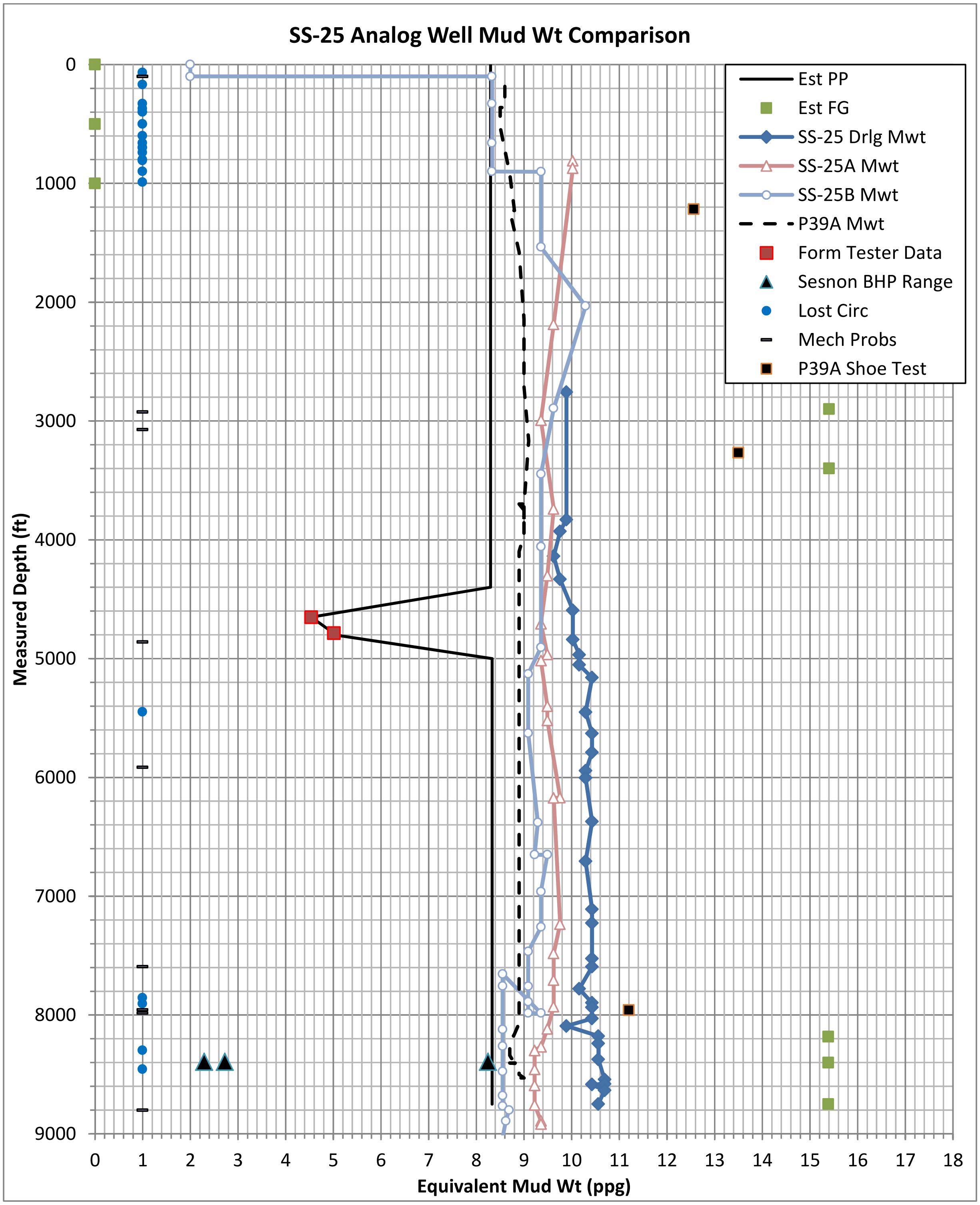


Figure 21. Analog Mud weight Comparison

In general, the longer an open hole interval is, and the longer it is "open", the greater the chance that the hole condition will deteriorate (sloughing) which can be problematic. In many wells the time can be measured in days or hours. However, as summarized below, a review of several wells with open hole sections exposed for long periods would suggest that sloughing is not a major issue in the Aliso Canyon field, provided a suitable inhibitive drilling fluids system is used.

- SS-25 Open Hole Exposure Time
  The open hole length between the 11-3/4" and the 7" casing strings was 7,590 ft. The upper section of the 10-5/8" hole was exposed for 125 days. Note that a review of the drilling data shows that this well was not drilled with OBM as is suggested by the wireline log headers. WBM was used with some additions of crude oil.

- SS-25A Open Hole Exposure Time
  The open hole length between the 13-3/8" and the 8-5/8" casing strings was 7,308 ft. The upper section of the 11" hole was exposed for 21 days.

- SS-25B Open Hole Exposure Time
  The open hole length between the 13-3/8" and the 8-5/8" casing strings was 6,747 ft. The upper section of the 11" hole was exposed for 28 days.

- P-39A Open Hole Exposure Time
  The open hole length between the 9-5/8" and the 7" casing strings was 4,653 ft. The upper section of the 8-1/2" hole was exposed for 28 days.

- SS-4-0 Open Hole Exposure Time
  Repairing the well after the 1994 earthquake involved exiting the 7" casing at 7,008 ft after extensive milling and fishing, drilling two sidetracks, plugging back, drilling a third sidetrack and then reentering the 7" at 7,666 ft. This ~600 ft hole interval was exposed for 119 days.

  Later, the 7" was cut and pulled. A cement plug was set below the 10-3/4" shoe at 4,852 ft in August 1994. In September 1995, the well was reentered for a sidetrack. No cement was found below the shoe and the well was successfully sidetracked. This short section of open hole had been exposed for around 387 days.

5.5 SS-25 Location Description

For reference, a top view of the SS-25 location prior to the removal of the SS-25A and B heat shields and the bridge that includes the site's basic dimensions is provided below.

Figure 22. SS-25 Location and Dimensions

6 SS-25 Post Well Kill Status

Several top-kill attempts were made after the SS-25 leak was first detected which proved unsuccessful leading to the decision to drill a relief well. A discussion of these initial kill attempts is beyond the scope of this document; however the following aspects could have an impact on the operations during Phase 3:

- 3 barite plugs were pumped over a period of several days as, shown below. Although some barite returns to surface were reported on 18-Nov, the location and status of these plugs are unknown, and some barite could still be in the 2-7/8" x 7" annulus.
    - 19 bbls of 18 ppg plug on 15 November 2015
    - 35 bbls of 18 ppg plug on 18 November 2015
    - 35 bbls of 18 ppg plug on 24 November 2015
- A plug was set in the tubing at 8,393 ft after the first kill attempt, and the tubing was perforated from 8,387 to 8,391 ft to allow circulation as shown in Figure 24.

The P-39A relief well intersected the SS-25 well at 8,615 ft MD in P-39A between the packer and top of the 5-1/2" liner in SS-25 as illustrated in Figure 23. A relief well kill operation was conducted with an 8.9 ppg mud and the SS-25 well was successfully killed.

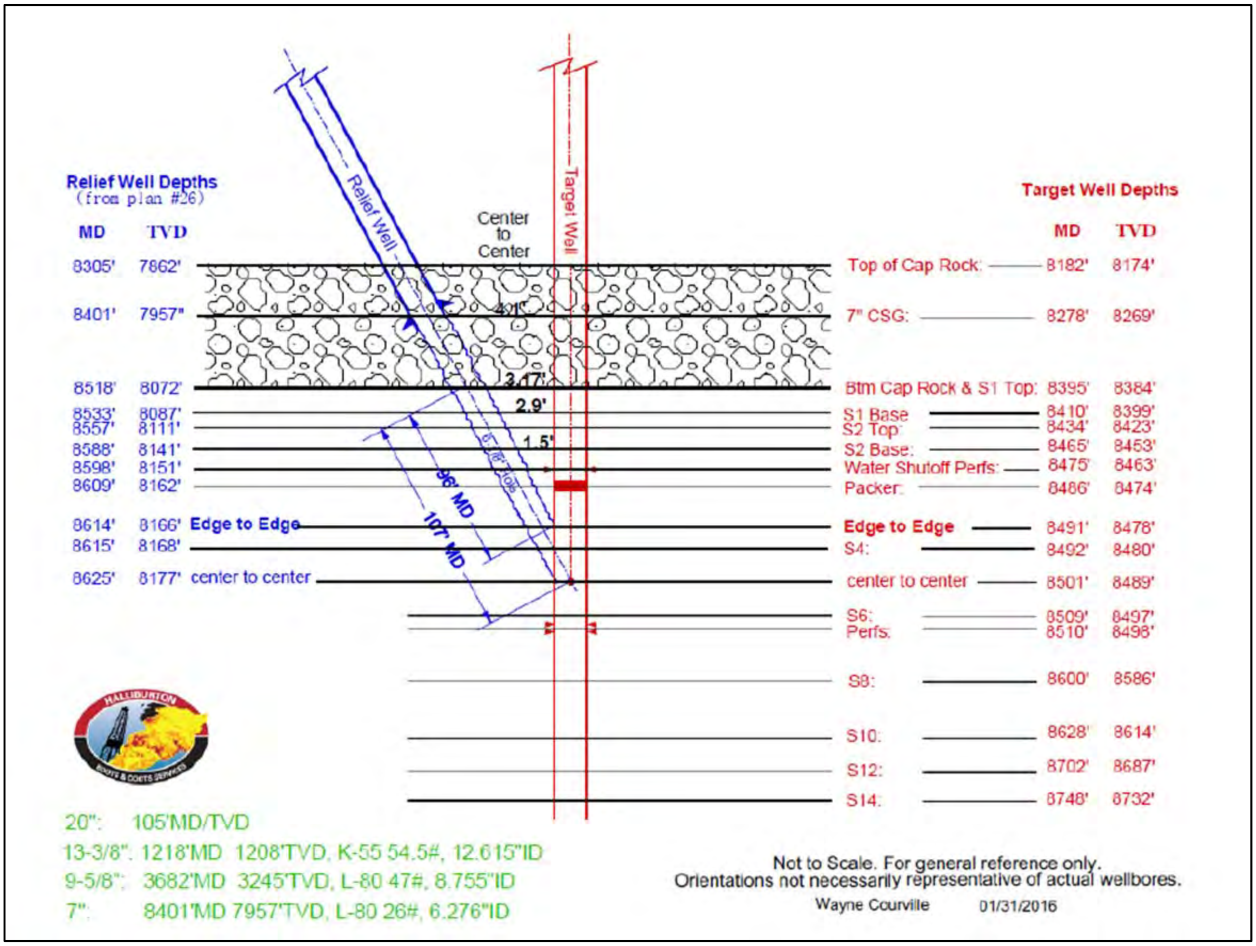


Figure 23. Planned P-39A Relief Well Intersection Concept

After monitoring the well the window cut on the SS-25 well was extended to facilitate setting cement plugs. Two cement plugs were then set to isolate the gas storage reservoir. The estimated TOC in the 2-7/8" x 7" annulus is 7,590 ft based on a CBL run on 17 February 2016. The TOC in the tubing was tagged at 8,175 ft with wireline during a noise/temperature log on 16 February 2016. A portion of the CBL log showing the TOC in the annulus is provided in Section 15.

The status of the SS-25 well just after the kill operation is shown in the wellbore schematic in Figure 25. The bottom of the well is sealed with cement plugs as shown. There is 896 ft of cement in the 2-7/8" by 7" annulus, and 321 ft of cement inside the tubing. The completion equipment run on the tubing string is therefore covered by cement on the inside and outside of the tubing.

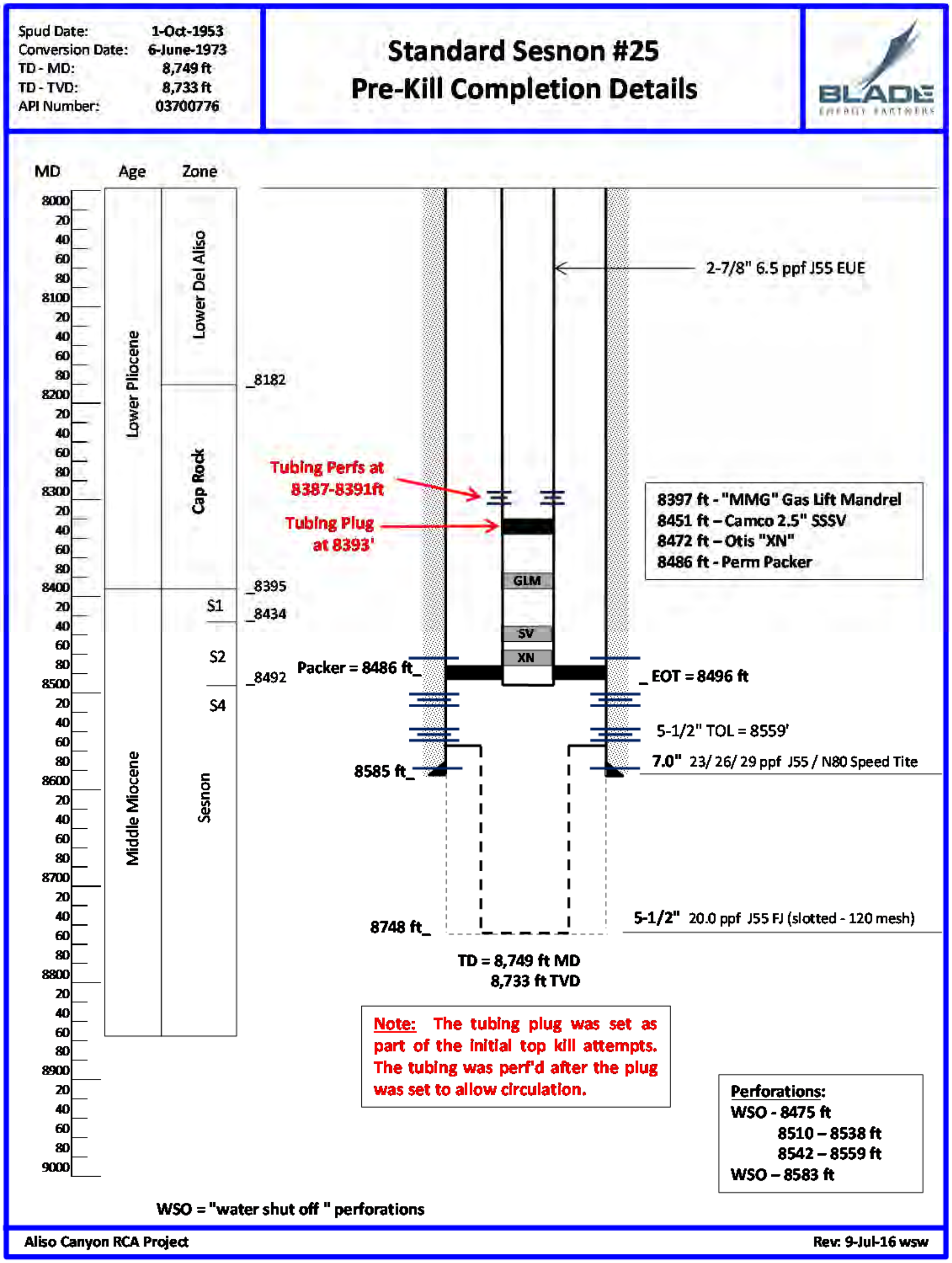


Figure 24. SS-25 Pre-Kill Completion Detail

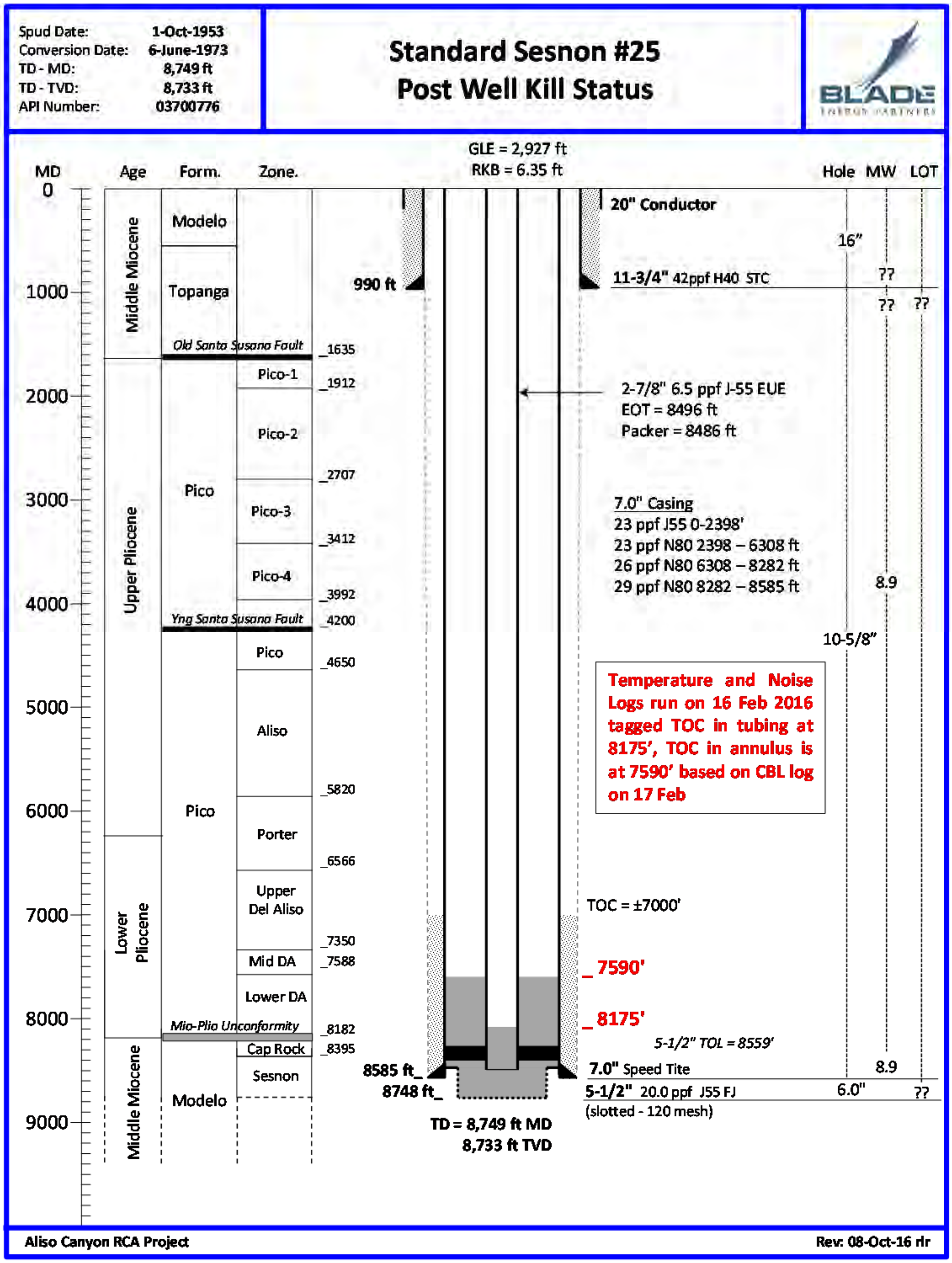


Figure 25. SS-25 Post Kill Wellbore Status Schematic

6.1 Casing Program

Details for the casing and tubing are shown in Table 5 below. There are no records about setting the conductor casing. The conductor was recently physically measured and shown to be 20" diameter.

Table 5. Casing and Tubing Data

Tubulars Data

String	OD (in)	Weight (ppf)	Grade	Nom Wall (in)	Nom ID (in)	Drift ID (in)	Setting Depths (MD) Hanger	Setting Depths (MD) Base	Length ft	Conn	Air Wt lbs
Conductor	20"	?	?	?	?	?	?	?	?	?	---
Surface	11-3/4"	42.0	YT H40	0.333	11.084	10.928	0	990	990	API STC	41,580
Production	7.0"	23.0	J55	0.317	6.366	6.241	0	2,398	2,398	Speedtite	55,154
		23.0	N80	0.317	6.366	6.241	2,398	6,308	3,910	Speedtite	89,930
		26.0	N80	0.362	6.276	6.151	6,308	8,282	1,974	Speedtite	51,324
		29.0	N80	0.408	6.184	6.059	8,282	8,585	303	Speedtite	8,787
Tubing	2-7/8"	6.5	N80	0.217	2.441	2.347	0	184	184	API EUE	1,196
		6.5	J55	0.217	2.441	2.347	184	8,496	8,312	API EUE	54,028

Tubulars Nominal Performance

String	OD (in)	Weight (ppf)	Grade	Conn	Pipe Data Nom Wall	Pipe Data Burst	Pipe Data Collapse	Pipe Data Tension	Connection Data OD	Connection Data ID	Connection Data Burst	Connection Data Tensile
Conductor	20"	?	?	?	?	?	?	?	?	?	?	?
Surface	11-3/4"	42.0	YT H40	API STC	0.333	1,980	1,040	478,000	12.750	11.084	1,980	307,000
Production	7.0"	23.0	J55	Speedtite	0.317	4,360	3,270	366,000	7.369	6.366		
		23.0	N80	Speedtite	0.317	6,340	3,830	532,000	7.369	6.366		
		26.0	N80	Speedtite	0.362	7,240	5,410	604,000	7.369	6.276		
		29.0	N80	Speedtite	0.408	8,160	7,030	676,000	7.369	6.184		
Tubing	2-7/8"	6.5	N80	API EUE	0.217	10,570	11,100	145,000	3.668	2.441	10,570	145,000
		6.5	J55	API EUE	0.217	7,265	7,676	99,661	3.668	2.441	7,260	99,700

7" OD's per Logan String Book

"Speedtite" apparently is a 2-step integral upset connection. The box upset OD has not been positively confirmed, but is either 7.369" or 7.444". Additional connection information is provided in Section 16.

6.2 Tubing String Details

Details of the tubing string and gas storage configuration completion equipment are shown Table 6 below.

Table 6. Tubing Stack-up

Description	Length (ft)	Top of Tool (ft)	Bottom of Tool (ft)
DFE	6.35		
Tubing Hanger	0.50	6.35	6.85
6 Jts 2-7/8" 8 RD EUE N-80 Tubing	183.68	6.85	190.53
265 Jts 8 RD EUE J-55 Tubing	8,202.59	190.53	8,393.12
Pup Jt 8 RD EUE N-80 Tubing	4.00	8,393.12	8,397.12
Camco MMG Mandrel with DCRT valve	8.43	8,397.12	8,405.55
Coupling	0.67	8,405.55	8,406.22
1 Jt 2-7/8" 8 RD EUE N-80 Tubing	31.40	8,406.22	8,437.62
Pup Jt 8 RD EUE N-80 Tubing	2.15	8,437.62	8,439.77

Description	Length (ft)	Top of Tool (ft)	Bottom of Tool (ft)
Camco SC-1 Safety System (annular flow safety system)	15.27	8,439.77	8,455.04
Camco 20 ft Blast Joint	19.77	8,455.04	8,474.81
Otis XN No-Go Nipple	1.17	8,474.81	8,475.98
Camco 10 ft Blast Joint	9.67	8,475.98	8,485.65
Baker Latch-in Locator	1.10	8,485.65	8,486.75
Baker Seal Assembly	4.20	8,486.75	8,490.95
Baker Production Tube	5.26	8,490.95	8,496.21

6.3 Wellhead Details

The wellhead stack-up is shown in Figure 26. The stack-up is based on documents from the well file and modifications during the well failure and well control events. The two crown valves shown are based on onsite observations. Note that the 7” casing was landed with 196,000 lbs of tension. All valve and flange specs need to be verified.

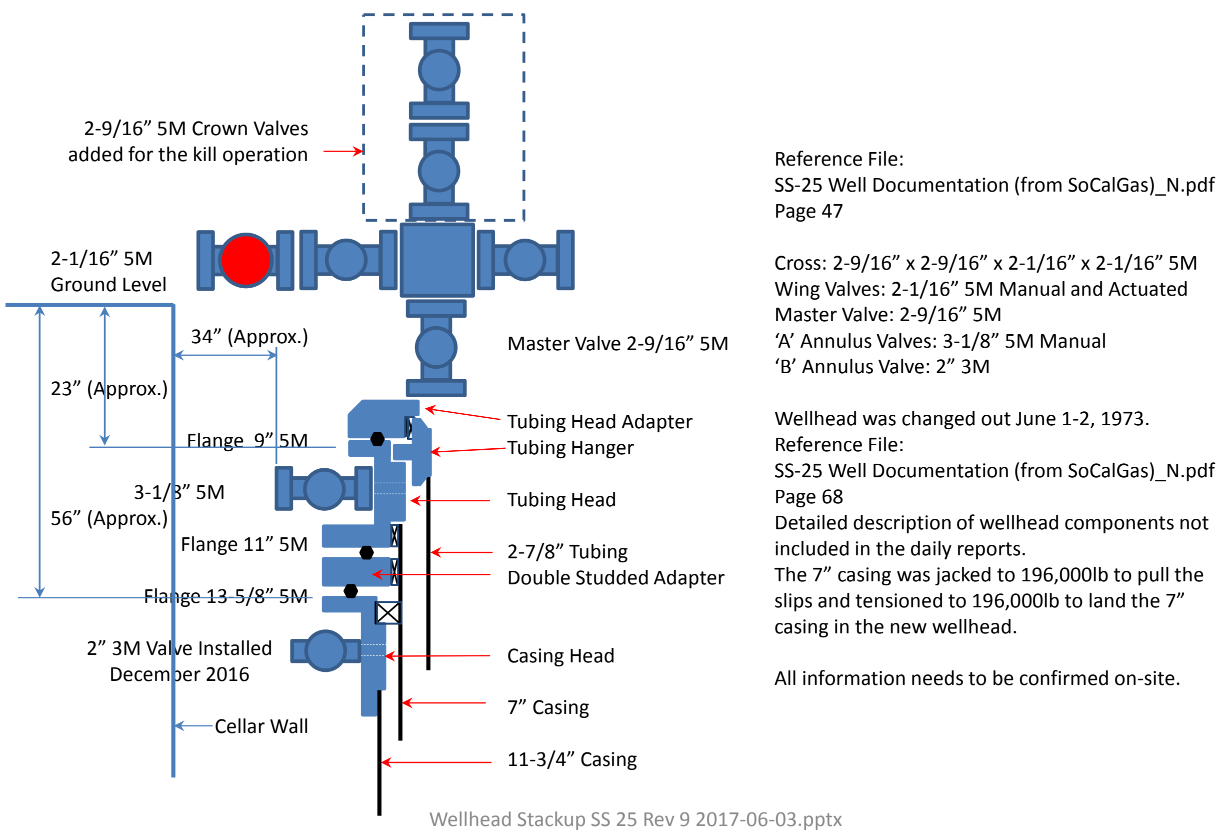


Figure 26. Wellhead Stack-up

6.4 2-7/8" Tubing Buckling Analysis

For reference, a buckling analysis of the 2-7/8" was done assuming the following inputs:

- 2-7/8" 6.4 ppf N80 and J55 EUE
- No Motion packer set at 8,486 ft
- Tubing landed with 10,000 lbs compression on the packer in February 1979
- Fluid density of 8.4 ppg.

As shown in Figure 27, the tubing is buckled at ~6,600 ft, and the buckling curvature is zero down to ~6,900 ft. In other words, the tubing is not buckled above ~6,600 ft.

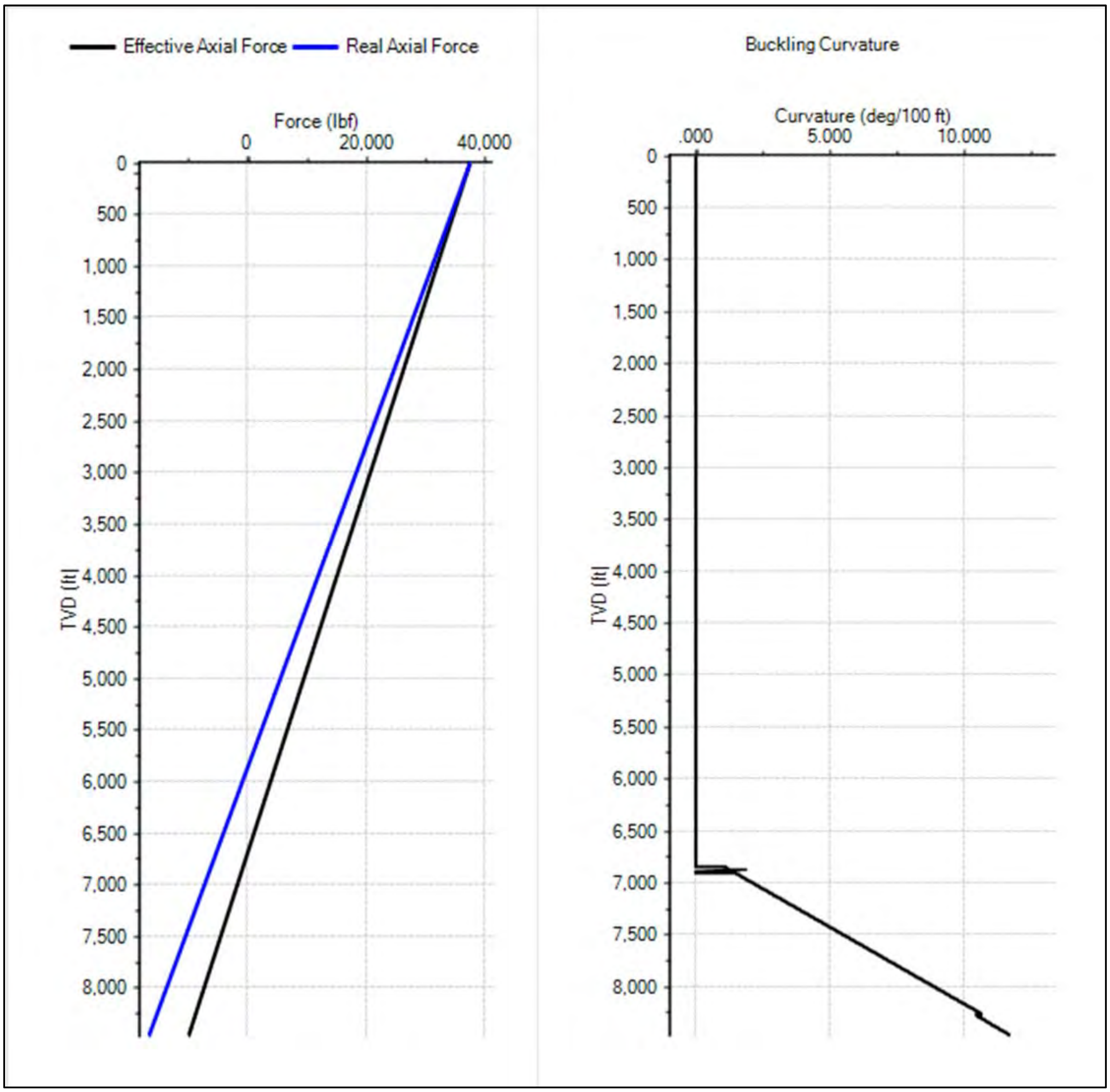


Figure 27. 2-7/8" Tubing Buckling Analysis

6.5 7" Casing Tension Profile

The as-cemented tension at the top of the 7" casing when it was originally run is calculated to be 148,000 lbs. As noted above, the string was landed with 196,000 lbs of tension after the wellhead was changed out. The slips were therefore set with 48,000 lbs of overpull.

For reference, the as-cemented and overpull tension load cases are shown in Figure 28. Also shown are the nominal tensile ratings for the various sections of the 7" string after being de-rated for temperature.

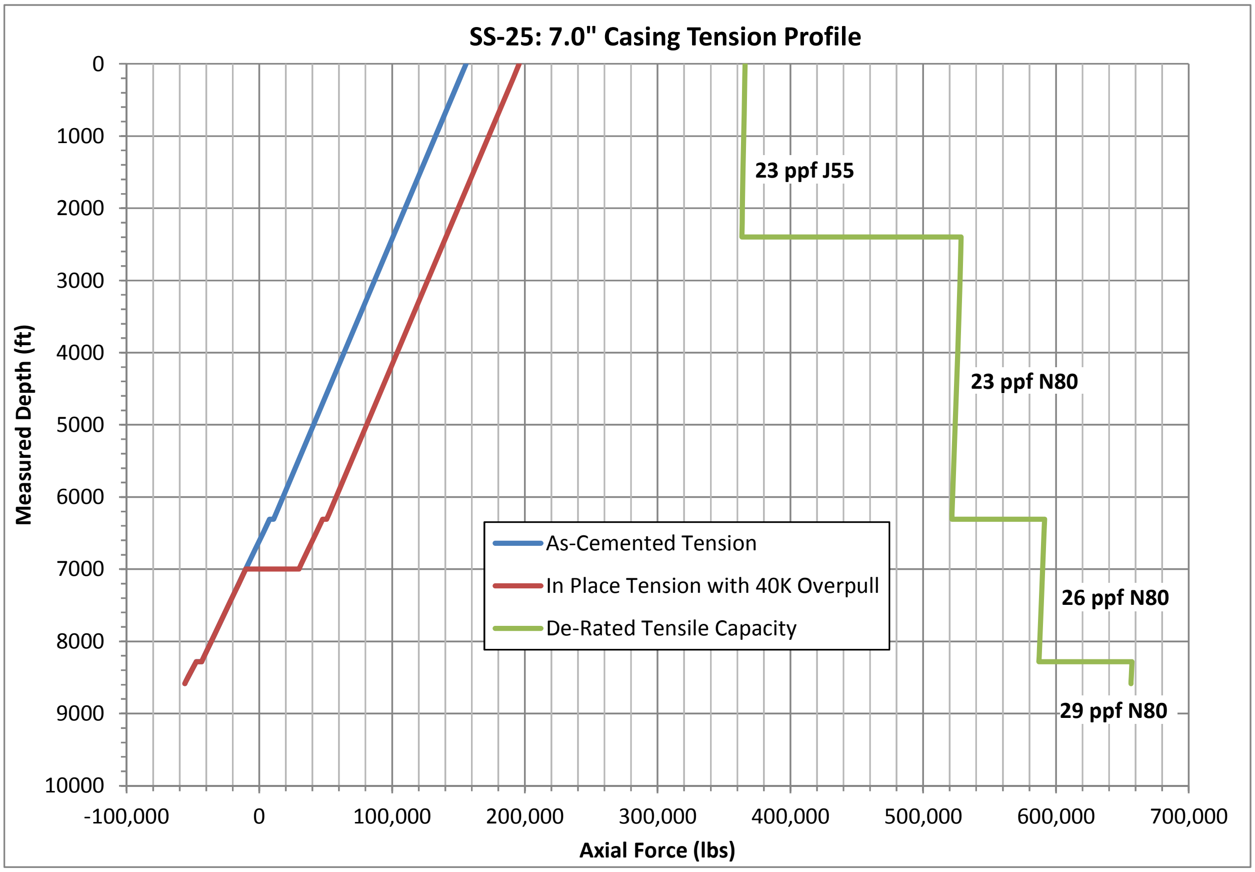
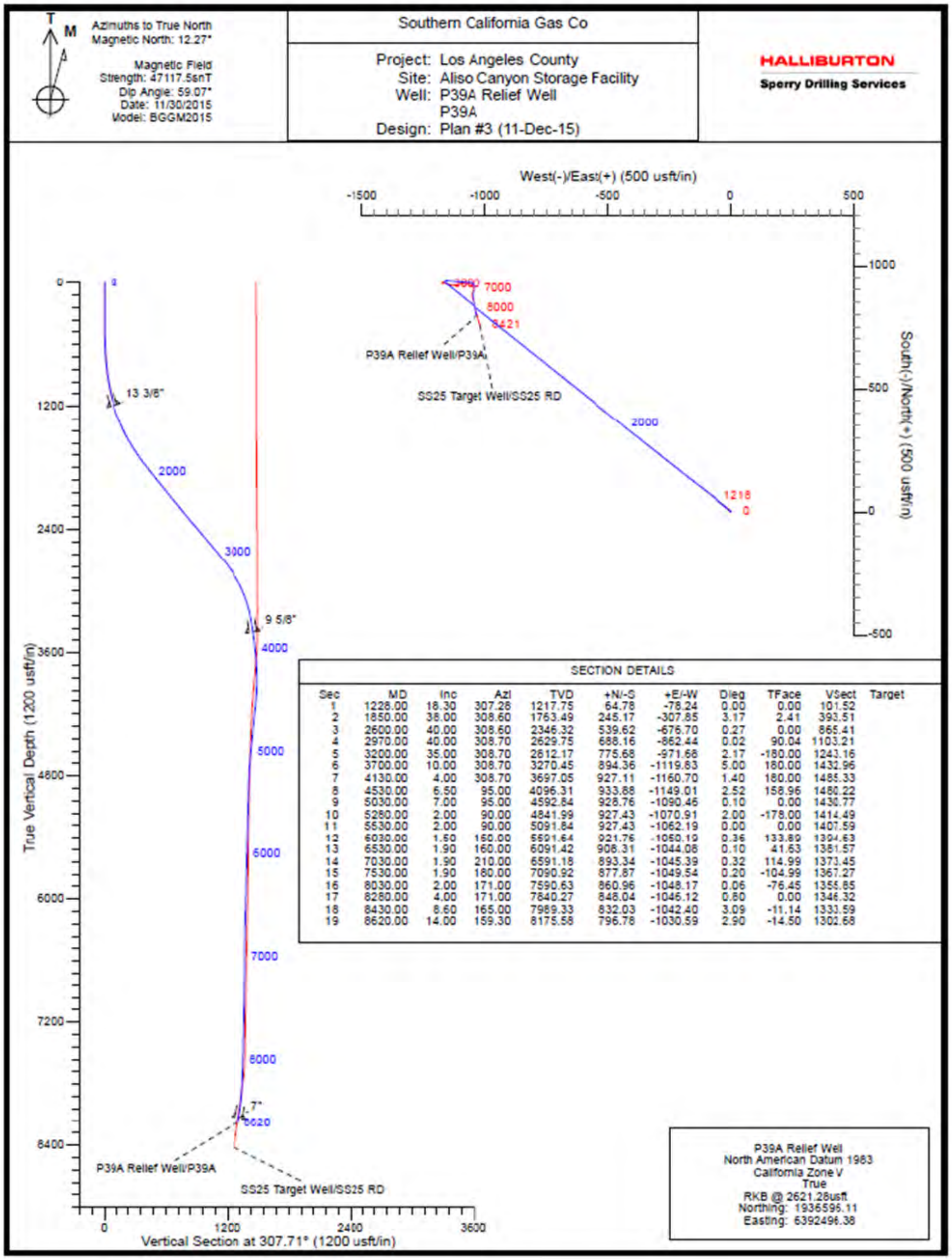


Figure 28. 7" Casing In-Place Tension Profile

6.6 Relief Well Directional Detail

The P-39A relief well was directionally drilled towards SS-25, until the wellbore was in close proximity of the SS25 well at around 3,700 ft, as shown in Figure 29. The P-39A well path then essentially paralleled that of SS-25 until the intersection point at 8,615 ft.



SECTION DETAILS

Sec	MD	Inc	Azi	TVD	+N/-S	+E/-W	Dleg	TFace	VSect	Target
1	1228.00	18.30	307.28	1217.75	64.78	-78.24	0.00	0.00	101.52	
2	1850.00	38.00	308.60	1763.49	245.17	-307.85	3.17	2.41	393.51	
3	2600.00	40.00	308.60	2346.32	539.62	-676.70	0.27	0.00	865.41	
4	2970.00	40.00	308.70	2629.75	688.16	-862.44	0.02	90.04	1103.21	
5	3200.00	35.00	308.70	2812.17	775.68	-971.68	2.17	-180.00	1243.16	
6	3700.00	10.00	308.70	3270.45	894.36	-1119.83	5.00	180.00	1432.96	
7	4130.00	4.00	308.70	3697.05	927.11	-1160.70	1.40	180.00	1485.33	
8	4530.00	6.50	95.00	4096.31	933.88	-1149.01	2.52	158.96	1480.22	
9	5030.00	7.00	95.00	4592.84	928.76	-1090.46	0.10	0.00	1430.77	
10	5280.00	2.00	90.00	4841.99	927.43	-1070.91	2.00	-178.00	1414.49	
11	5530.00	2.00	90.00	5091.84	927.43	-1062.19	0.00	0.00	1407.59	
12	6030.00	1.50	160.00	5591.64	921.76	-1050.19	0.36	133.89	1394.63	
13	6530.00	1.90	160.00	6091.42	906.31	-1044.06	0.10	41.63	1381.57	
14	7030.00	1.90	210.00	6591.18	893.34	-1045.39	0.32	114.99	1373.45	
15	7530.00	1.90	180.00	7090.92	877.87	-1049.54	0.20	-104.99	1367.27	
16	8030.00	2.00	171.00	7590.63	860.96	-1048.17	0.06	-76.45	1355.85	
17	8280.00	4.00	171.00	7840.27	848.04	-1046.12	0.80	0.00	1346.32	
18	8430.00	8.60	165.00	7989.33	832.03	-1042.40	3.09	-11.14	1333.59	
19	8620.00	14.00	159.30	8175.58	796.78	-1030.59	2.90	-14.50	1302.68	

Figure 29. P-39A Relief Well and SS-25 Directional Comparison

Table 7 shows the estimated wellbore center to center distance between the SS-25 and P-39A wells.

Table 7. Distance between P-39A and SS-25 Wellbores

SS-25 MD (ft)	SS-25 TVD (ft)	P-39A MD (ft)	P-39A TVD (ft)	Distance Between Wells (ft)
3,643	3,643	3,765	3,331	19.0 ± 10
3,726	3,726	3,848	3,414	10.8 ± 5
3,829	3,826	3,949	3,514	10.4 ± 3
3,977	3,977	4,100	3,665	12.0 ± 3
4,057	4,056	4,180	3,744	13.0 ± 3
4,358	4,355	4,480	4,043	9.8 ±3
4,736	4,733	4,858	4,421	14.9 ± 4
5,245	5,241	5,367	4,929	18.4 ± 5
5,759	5,754	5,881	5,442	22.0 ± 5
6,470	6,465	6,592	6,153	22.0 ± 5
6,955	6,950	7,077	6,638	17.5 +8/-4
7,475	7,471	7,598	7,159	8.7 +4/-2
7,584	7,580	7,707	7,268	5.1 +2/-1
7,674	7,670	7,797	7,357	3.2 ± 0.5
7,734	7,729	7,857	7,417	2.4 ± 0.4
7,825	7,820	7,948	7,508	4.8 ± 1.0
7,944	7,939	8,067	7,627	6.75 ± 1.5
8,034	8,028	8,157	7,716	4.75 ± 1.0
8,114	8,108	8,237	7,795	5.2 ± 1.0
8,214	8,206	8,337	7,894	5.1 ± 1.0
8,277	8,268	8,400	7,956	4.2 ±0.8
8,325	8,315	8,448	8,003	4.2 ±0.8
8,376	8,366	8,499	8,054	2.7 ± 0.5
8,406	8,395	8,529	8,083	2.5 ± 0.5
8,436	8,425	8,559	8,113	1.9 ± 0.3
8,461	8,449	8,584	8,137	1.65 ± 0.3
8,475	8,464	8,599	8,152	1.2 ± 0.2
8,476	8,465	8,600	8,153	0.85 ± 0.1
8,491	8,480	8,616	8,168	0.62 ± 0.05

7 SS-25 Current Status – Post Phase 1

This section describes the current status of the SS-25 well based on the results of the information gathered during Phase 1. It therefore serves as the starting point for the planning of Phase 3.

During Phase 1 several diagnostic wireline logs were run in the 2-7/8" tubing in order to find out as much information as possible about the condition of the tubulars to aid in the Phase 3 planning, and in the event that only a limited amount of the tubulars are able to be recovered during Phase 3. The key logging results are described below.

Table 8. List of SS-25 Diagnostic Logs

No.	Date	Log Type	Provided By
1	7 Apr-16	GR/CCL/JCGR: Gamma Ray, Casing Collar Locator, Junk Catcher, Gauge Ring	Baker Hughes
2	8 Apr-16	ICAL: 2-7/8" Tubing 24 Arm Imaging Caliber	Baker Hughes
3	12 Apr-16	HPT: High Precision Temperature	Versa-Line
4	13-18 Apr-16	SNL: Spectral Noise Log	Versa-Line
5	18-19 Apr-16	MID-2: Magnetic Image Defectoscope-2, 2-7/8" and 7"	Versa-Line
6	20 Apr-16	MID-3: Magnetic Image Defectoscope-3, 11-3/4"	Versa-Line
7	20-22 Apr-16	MVRT: Micro Vertilog Flux Leakage, 2-7/8"	Baker Hughes

The HPT and SNL logs were run to take high precision measurements of the subsurface temperature and to identify possible areas of fluid flow behind the 7". The MID and MVRT logs are designed to inspect downhole tubulars for potential pipe body damage. The MID log runs were capable of investigating all three strings (2-7/8", 7" and 11-3/4") and determine whether there has been metal loss. The MVRT log was intended to detect OD and ID defects on the 2-7/8" tubing. The results of these logs suggest the following:

- The HPT log showed significant low temperature anomalies at 140 and 340 ft where the temperature at each depth was measured at 46ºF. The SNL recorded distinct noise anomalies between 252 and 294 ft, and around the 11-3/4" casing shoe from 820 to 1,200 ft.
- The 2-7/8" tubing shows minimal wall loss based on the results of the caliper and MID-2 logs. The maximum ID and minimum ID of some tubing joints exhibit a "bow" shaped appearance which seems to be a manufacturing artifact.
- The 7" casing exhibits significant metal loss at 895 ft and at 4,456 ft as evidenced by the results of the MID-2 log results. The MVRT log also shows an anomaly outside the 2-7/8" tubing at 891 ft.
- The 11-3/4" casing exhibits significant metal loss at 151 ft and at 192 ft based on the MID-3 log results.

A summary of the HPT, SNL and MID log results are shown in Figure 30 and Figure 31. A detailed discussion of the Versa-Line log results can be found in their report titled*: "SS 25 HPT SNL MID Results Discussion May 12th 2016 - FINAL VERSION.pdf".* The MVRT log confirmed minimal wall loss in the 2-7/8" tubing, and a similar bowing effect was noted on some joints as seen on the MID log.

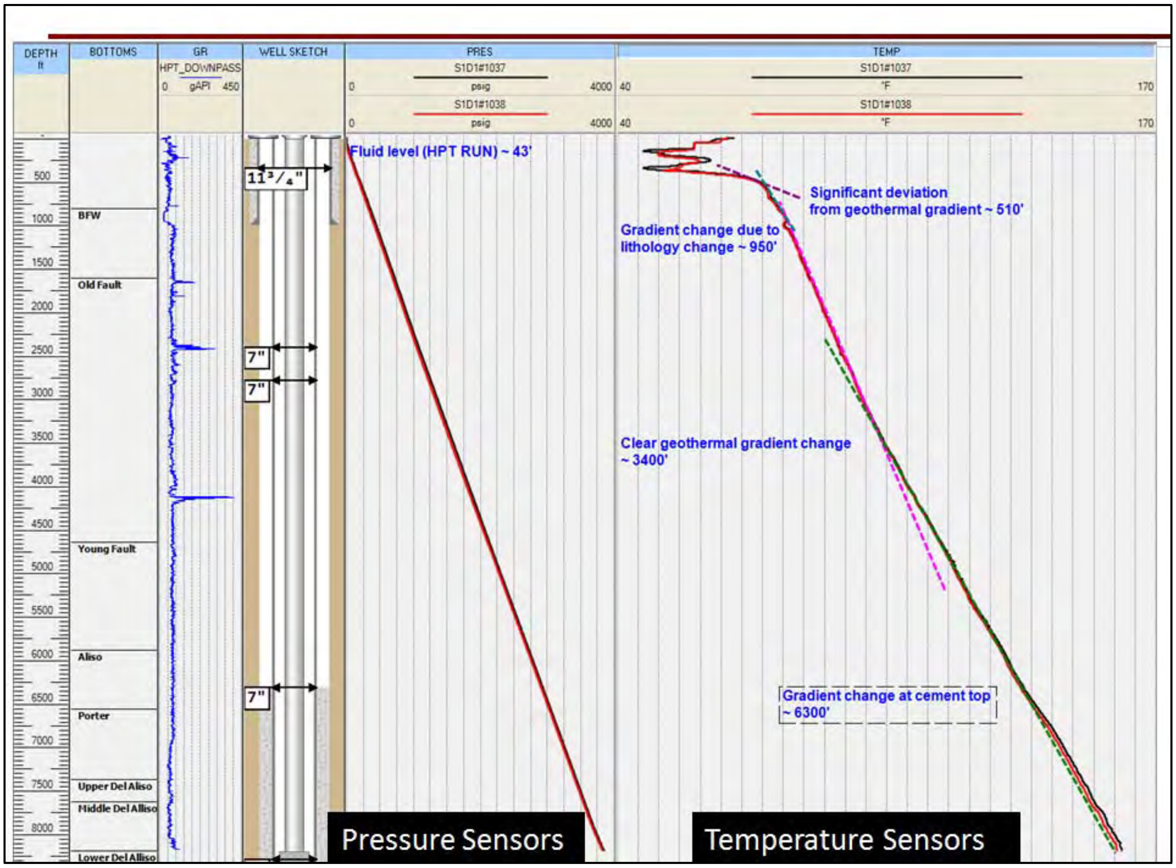


Figure 30. SS-25 HPT Log Results

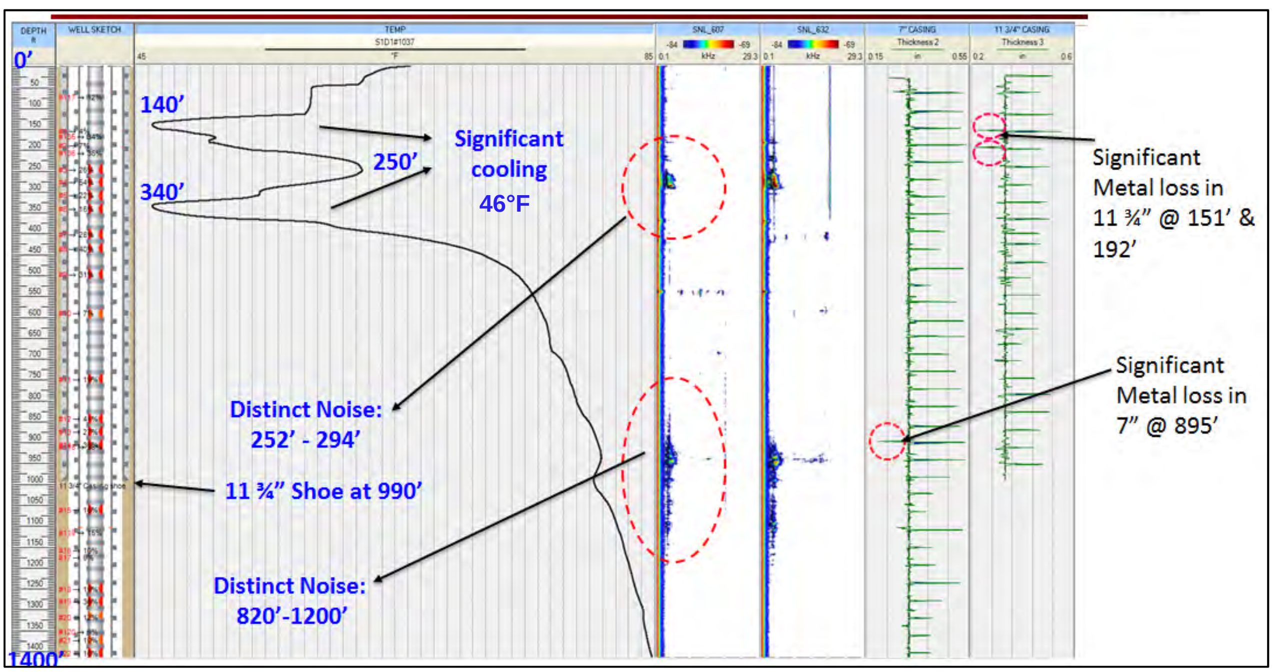


Figure 31. SS-25 HPT-SNL-MID Log Summary Results from 25 to 1,400 ft

For reference, Table 9 lists the files names for the various diagnostic logs that were run.

Table 9. SS-25 Diagnostic Log File Reference

Log Type	File Name
GR/CCL/JCGR	Southern_California_SS_#25_HCAL_PRELIMINARY_MVRT_HCAL_COMBO_LOG_2016.PDF
2-7/8" ICAL	Southern_California_SS_#25_HCAL_EVAL_2016.PDF
MID-2/3	GNPT_VSL_WL_STANDARD SESON#25_03700776_MID ANALYSIS_06.18.2016_WITHOUT CALIPER.pdf
MID-2/3	WL_STANDARD SESON#25_03700776_MID ANALYSIS_06.18.2016_WITH CALIPER.pdf
SNL-HPT-MID	Standard Seson#25_ SNL-HPT-MID_INTEGRATED_LOG_APRIL 12 TO 20-2016.pdf
SNL-HPT-MID	Standard Seson#25_ SNL-HPT-MID_LOG_APRIL 12 TO 20-2016_1-3000 SCALE.pdf
2-7/8"MVRT	Southern_California_SS_#25_MVRT_EVAL_with_expanded_scale__2016.PDF
2-7/8" MVRT & 2-7/8" ICAL	Southern_California_SS_#25_MVRT_HCAL_COMBO_LOG_2016.PDF

In order to better understand the temperature anomaly evident on the HPT log, an HPT/SNL/MID logging suite was subsequently run in both the SS-25A and SS-25B wells. In addition, a shallow geophysical investigation was completed.

7.1 Supplementary Logging on SS-25A and SS-25B

As shown in Figure 32, the shallow low temperature anomaly was also present in the SS-25A and SS-25B wells, and the lowest temperatures recorded, 41 and 43ºF respectively, were colder than what was measured in SS-25.

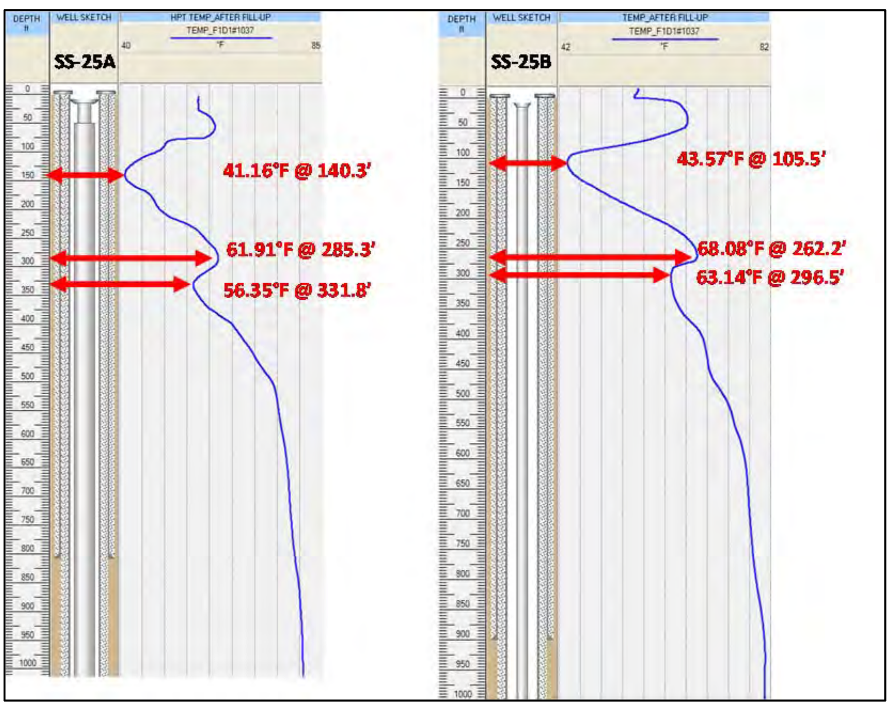


Figure 32. HPT Results for SS-2A and SS-25B

7.2 Shallow Geophysical Investigation

A shallow geophysical investigation was conducted between 15 August 2016 and 6 September 2016. The interpretation and analysis of the results is still ongoing at this time.

The purpose of the geophysical investigation is to provide information on the shallow geology around the SS-25 location down to approximately 1,312 ft below ground level. The investigation will aid in characterizing geological and hydrogeological features including the depth and location of faults and other geological structures, the depth and extent of aquifers, overburden thickness, bed rock delineation and shallow void mapping. The following surveying technologies were utilized:

- Nuclear magnetic Resonance (NMR)
- Electric Resistance Tomography (ERT)
- Seismic Refraction
- High Resolution Seismic Reflection
- Multichannel Analysis of Surface Waves (MASW)

Multiple survey lines were run at different orientations across the SS-25 pad. The survey lines used different electrode or geophone spacing which influences the depth of investigation and the resolution of the data. The NMR involved running different diameter survey loops around the circumference of the pad location. Table 10 shows the surveys that were completed, and Figure 33 shows a line orientation example from the 1.5m ERT survey.

Table 10. Shallow Geophysical Investigation Survey List

Survey Type	Lines Completed	Line Length (ft)
ERT: 1.5m electrode spacing	5	394
ERT: 5m electrode spacing	4	1,312
ERT: 10m electrode spacing	2	3,937
ERT: 22.5m electrode spacing	2	5,905
Seismic: 2m geophone spacing	2	938
Seismic: 5m geophone spacing	2	2,346
Seismic: MASW	1	460
NMR	2 loops	131 & 66

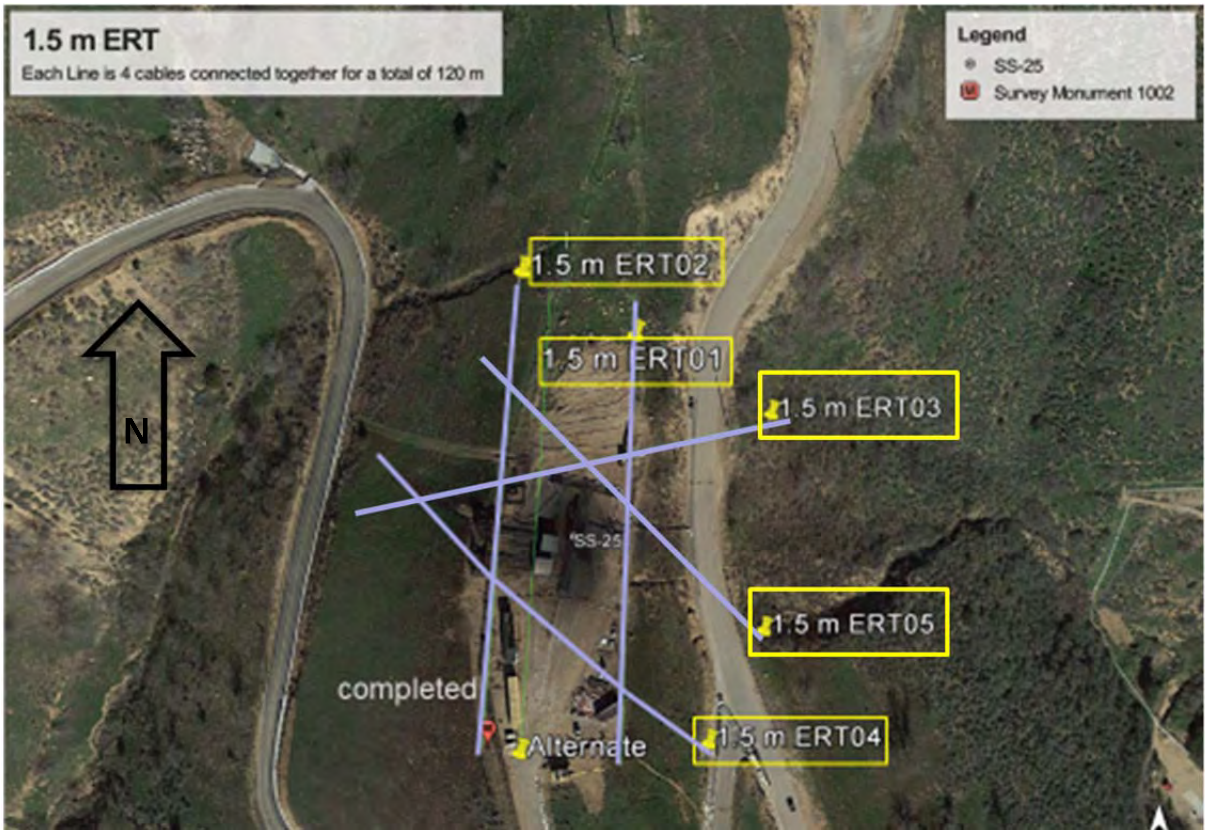


Figure 33. Survey Line Orientation Example - 1.5m Spacing ERT Survey

After this survey work was completed, four shallow boreholes were drilled on the SS-25 pad site in order to obtain core samples to further aid in characterizing the composition and strength of subsurface materials. This involved using a hollow-stem auger technique to drill through the upper soil and weathered bedrock interval (~50 ft) until reaching competent rock, and then using core drilling methods to obtain ~2" core samples down to a target depth of approximately 150 feet below ground surface.

The four boreholes were drilled and then logged between 6 September 2016 and 23 September 2016. The core samples were subsequently sent to a laboratory for analysis that includes the following tests.

- Grain-Size Analysis
- Atterberg Limits
- Unit Weight
- Moisture Content
- Direct Shear
- Unconfined Compression

After the boreholes were drilled, temperature, gamma ray/conductivity, NMR and optical tele-viewer wireline logs were run in each hole. A summary of the borehole details is shown in Table 11 and the approximate location of the boreholes are shown in Figure 34.

Table 11. Shallow Borehole Details September 2016

Shallow Geology Boreholes	B-1	B-2	B-3	B-4
Spud Date	Sept. 6th	Sept. 8th	Sept. 15th	Sept. 12th
Auger TD (ft)	42	45	57.5	70
Auger Size (in)	7.5	7.5	7.5	7.5
Top of Rock Core (ft)	42	45	57.5	70
Rock Core Bit Size (in)	3-3/4"	3-3/4"	3-3/4"	3-3/4"
Rock Core TD (ft)	150	120	135	102.5
Core Total Recovery (ft)	83.3	58.2	38.3	7.8
Core Recovery %	77%	78%	50%	24%
Max Depth (ft)	150	120	135	150
Drilling End Date	Sept. 8th	Sept. 10th	Sept. 18th	Sept. 15th
Temperature Log	Sept. 19th	Sept. 19th	Sept. 19th	Sept. 19th
Gamma Ray/Conductivity	Sept. 23rd	Sept. 19th	Sept. 19th	Sept. 19th
NMR Log	Sept. 22nd	Sept. 21st	Sept. 22nd	Sept. 21st
Optical Tele-viewer Log	Sept. 23rd	Sept. 23rd	Sept. 23rd	Sept. 23rd
Log Depth (ft)	39	49	133	97

Figure 34. Shallow Borehole Locations

7.3 SS-25 Current Status Summary

The current status of the SS-25 well, as of the end of Phase 1, is shown in Figure 35, and summarized below.

- The 2-7/8” tubing contains ~8.9 ppg WBM with a fluid level at 124 ft, confirmed in January 2017. The fluid level was at 43 ft prior to running wireline logs, so it is essentially full.
- The 2-7/8” x 7” annulus contains ~8.9 ppg WBM. The fluid level in January 2017 is 312 ft. The annulus may also contain the remains of 3 barite plugs that were pumped during the initial kill attempts.
- The 7” TOC is estimated to be at 7,000 ft. The annulus fluid, and the condition of the annulus above the TOC is unknown. The ‘B’ annulus fluid level in January 2017 is 344 ft.
- The Sesnon is isolated by cement plugs set in the tubing and in the tubing by casing annulus. The PBTD is therefore 7,590 ft.
- Diagnostic log results show minimal wall loss in the 2-7/8” tubing.
- Diagnostic log results show significant wall loss in the 11-3/4” casing at 151 and 192 ft.
- Diagnostic log results show significant wall loss in the 7” casing at 895 and 4,456 ft.
- There are significant low temperature anomalies at 140 and 340 ft where the temperature at each depth was measured at 46ºF.
- The assumed geothermal temperature to be used for thermal analysis is based on the HPT log results, and is shown in Figure 36.
- The log results of the High Precision Temperature (HPT) log run on 12 April 2016 are shown in Figure 37. This log clearly shows the two low temperature zones near the surface.
- The DTS temperature readings in January 2017, show a temperature of 32°F at 80 ft and 50°F at 300 ft.
- The DTS temperature readings in June 2017, show minimal temperature change from January 2017.

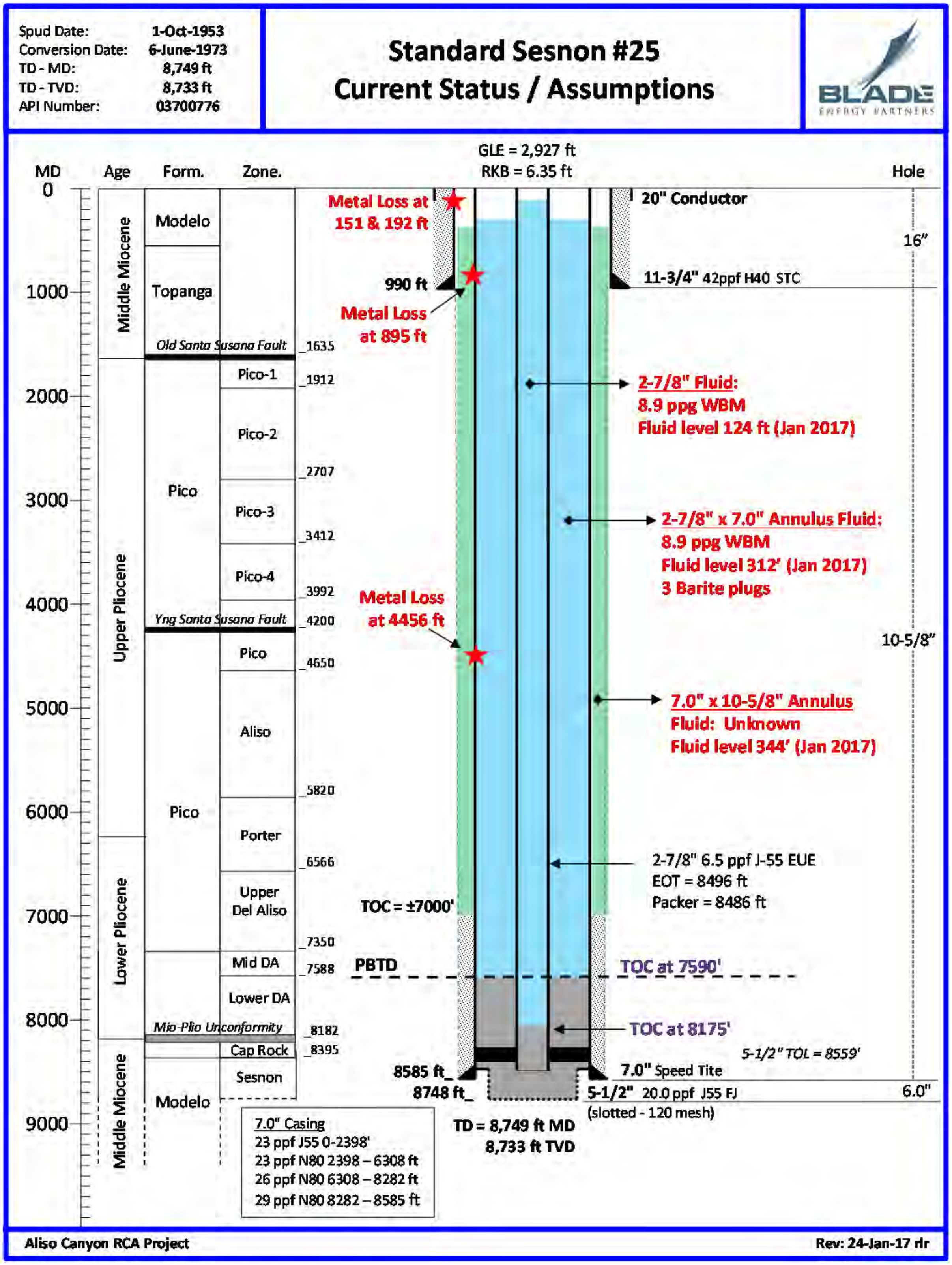


Figure 35. SS-25 Current Well Status, Post Phase 1

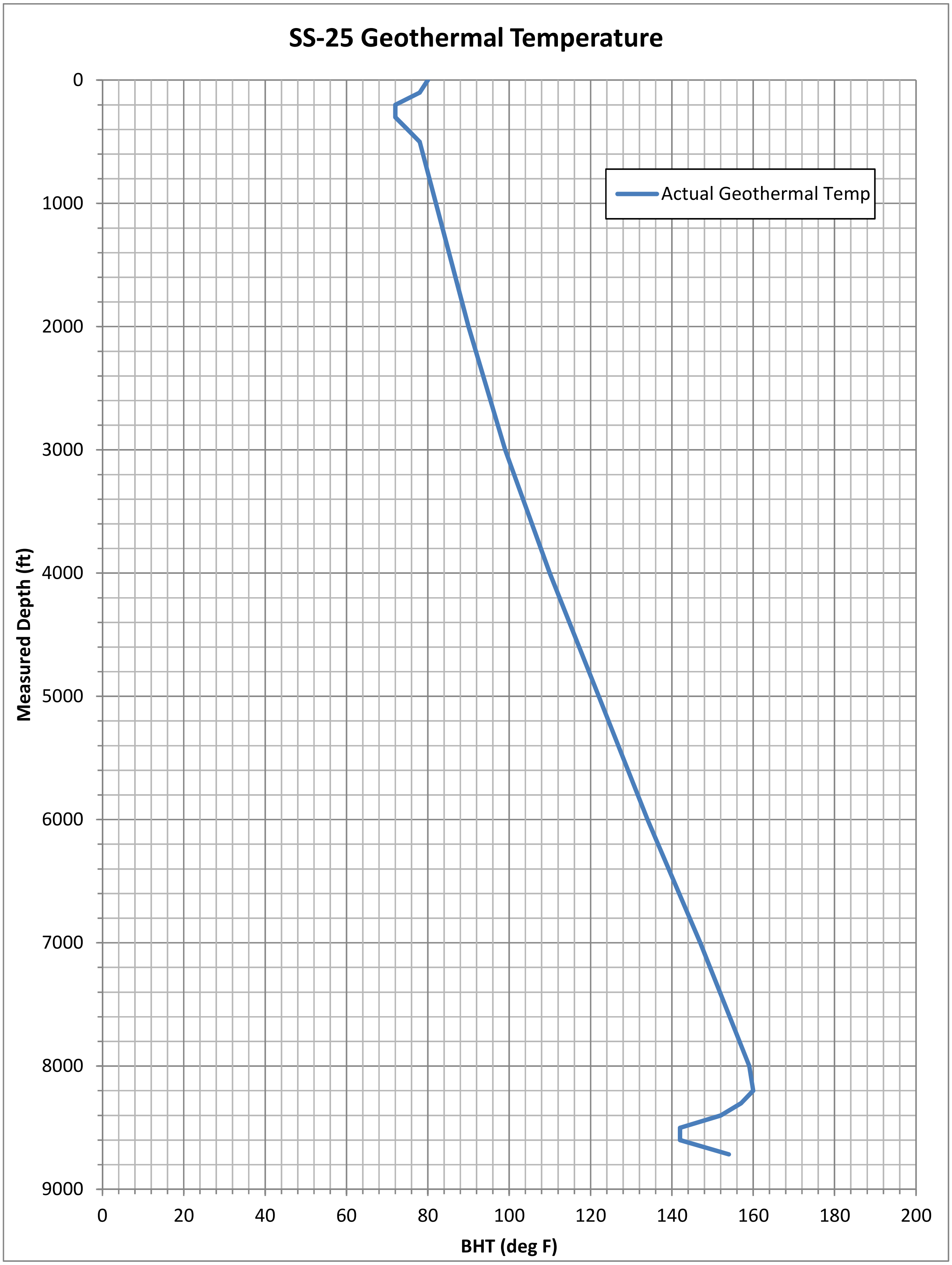


Figure 36. SS-25 Assumed BHT for Thermal Analysis

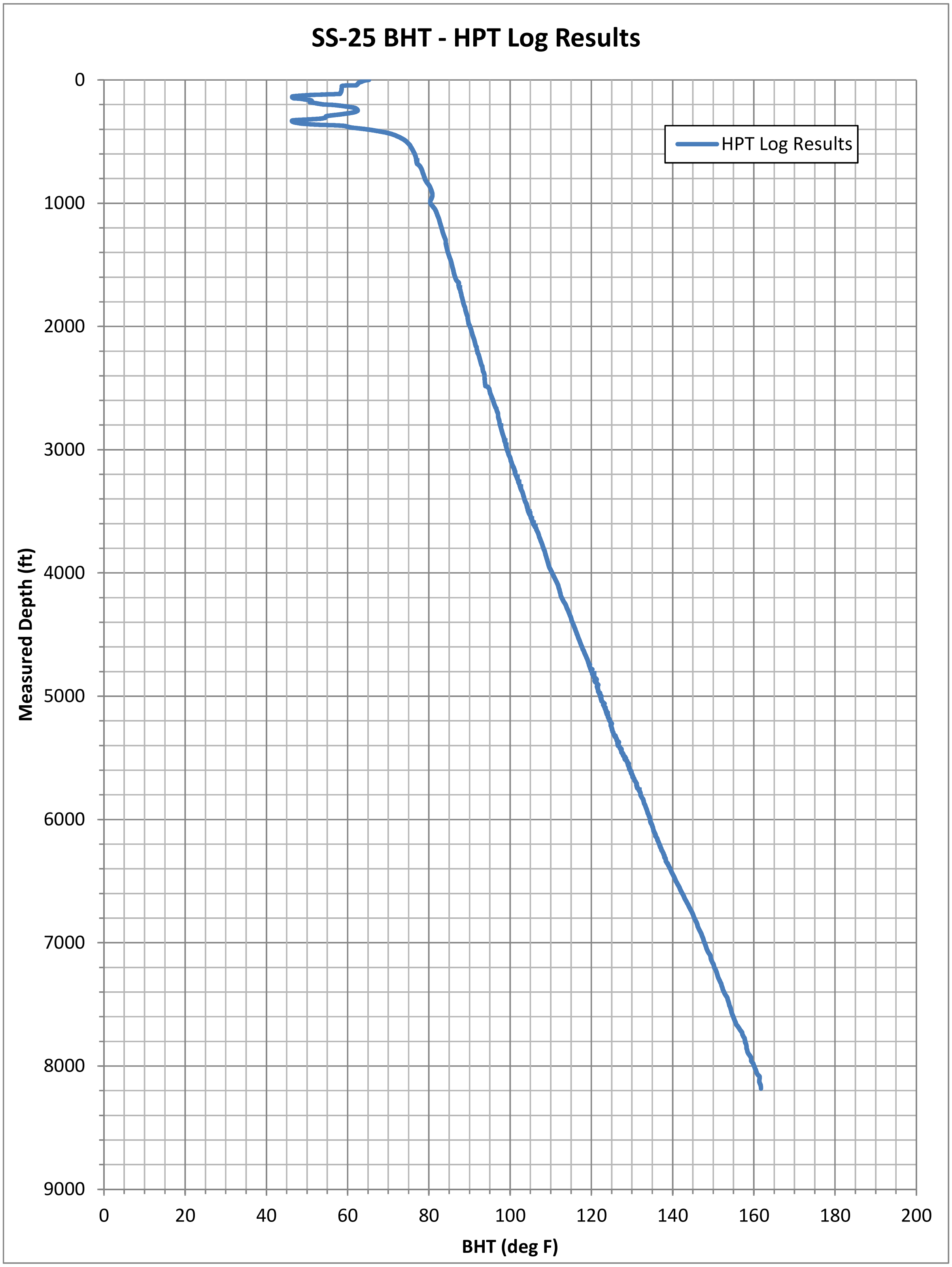


Figure 37. SS-25 High Precision Temperature Log Run 12 April 2016

8 Phase 3 Protocol and Operational Assumptions

The following are the key assumptions being used in the planning of Phase 3.

1. The well site has been restored by filling the crater that existed around the wellbore and is ready for a rig move in and rig up.
2. The cellar has been rebuilt and the wellhead has been surveyed to ensure that it is vertical.
3. The outlet valve to the “B” annulus on the wellhead has been replaced. (The 2-1/16” 3000 psi valve backed out or broke off during the well control event.)
4. The wellhead has been cleaned and inspected to ensure that it is operationally functional and undamaged from the well control events.
5. The integrity of the 7” production casing and the 11-3/4” surface casing is suspect based on the prior well control events, and the diagnostic wireline log results.
6. There is a need to compare the wellhead and tree configuration, flange sizes and pressure ratings with the schematic in Figure 26, make adjustments if necessary and source adapters as required for nippling up the BOP stack.
7. A 5M BOP stack is recommended to pull the tubing. The BOP will be NU on the 9” 5M tubing head flange.
8. A 5M BOP stack is recommended when the tubing head is removed to recover the upper part of the 7” casing. The BOP will be NU on the 13-5/8” 5M casing head flange.
9. Estimated BHP.
    a. Original Sesnon BHP was 3,600 psi at 8,300 ft TVD for an EMW of 8.34 ppg.
    b. The estimated BHP at the time of the well kill was 1,190 psi at 8,475 ft TVD for an EMW of 2.7 ppg. Based on Well SS-5 as reported in the Well 39A relief well kill procedure.
    c. The recommended mud weight for the extraction operations and plugging and abandonment is 9.0 ppg for an estimated overbalance of 284 psi based on original BHP.
10. Estimated downhole mud volume requirements. These volumes assume the tubing is cut around 7,600 ft.
    a. 44 bbls - estimated 2-7/8” tubing volume to 7,600 ft.
    b. 28 bbls - estimated 2-7/8” x 7” annulus volume to 895 ft.
    c. 237 bbls - estimated 2-7/8” x 7” annulus volume to 7,600 ft.
    d. 298 bbls - estimated 7” casing volume to 7,600 ft.
    e. 17 bbls - tubing displacement volume to 7,600 ft.
11. The fluid composition in the tubing and ‘A’ annulus is an unknown, however, based on the previous operations, it is believed that it will probably consist of a mixture of fluids including fluid that U-tubed from the relief well during the kill operation.

    The tubing fluid will be sampled at several depths prior to circulating the well using a wireline fluid sampler. Annulus fluid samples will be taken when the well is first circulated. Samples will be collected and documented for every 50 bbl circulated.

Samples will be collected and documented by Blade according to the Aliso Canyon RCA SS-25 Site Evidence Collection and Documentation Protocol, April 28, 2016, Version 008 (or latest version).

12. The well needs to P&A'd in such a way that it can be reentered, if necessary, at some future date per DOGGR requirements.
13. Samples of the mud and other fluids used in the well will be collected for the purpose of chemical fingerprinting. Further, the mud supplier will be required to provide the chemistry of the fluid. Details are included in Section 10.3.

8.1 Protection of Evidence during Phase 3A and Phase 3A Contingency

All well and wellbore equipment shall be considered "evidence". Therefore every effort shall be taken to improve the chance for recovery of casing, tubing and downhole equipment and to avoid inadvertent damage to equipment and/or evidence. During extraction of the tubing/casing a fishing operation may be required. A fishing operation has the potential to alter the evidence from its post blowout stage. However, this will be mitigated by careful attention to tool selection, operational procedures and processes. This implies careful service equipment selection and adhering to procedures that emphasize care over speed when running tools through the tubing and casing. This also includes minimizing erosion through a breach, hole, crack or other defect in the casing or tubing by circulating solids laden fluids.

It is assumed that there is a breach of the 7" casing that allowed gas to escape to the 11-3/4" casing and eventually to surface. The duration of the gas release was about 111 days (23 October 2015 to 11 February 2016). There were 7 separate attempts to kill the well using various density brines, drilling mud, high viscosity fluids and LCM. After some attempts, the LCM and liquids were found within the surface crater. If the initial failure was caused by a small crack, corrosion pit, or by another small defect it is likely that the localized area surrounding the failure has already been altered due to erosion from the passage of gas, liquid and solids. If the initial failure is a large opening (e.g. the threaded connection between two joints of 7" casing separated), the localized area may not be altered significantly. The surfaces of the failure may have been altered by the blowout event and the kill attempts.

By direct and indirect examination of numerous 7" casing joints, useful information can be extracted, not just on the failure, but on the larger data set. The intent of logging the 7" casing is to collect a large data set while the casing is still in situ. Other information can be collected while the 7" casing is still in place like whether or not the casing is capable of holding internal pressure. Vastly more data can be collected from the 7" casing when it has been recovered. Even if the location at which the failure occurred was substantially altered due the blowout conditions, with enough information on the surrounding area and distant area, a hypothesis could be put forth to determine the failure cause(s).

It is important to recognize that the collection of logging data may mildly alter the condition of the casing. Some examples like the multi-arm caliper and the wellbore casing scraper tool make contact with the ID of the casing. There may be tool marks on the casing as a result of the contact. The operations sequence and pictures of each tool before and after each run can be used to distinguish tool marks from the pre-existing marks.

Establishing if the integrity of the 7" casing has been compromised or not, can also produce stresses, however these stresses will be lower or equal to the pressures during operations and the blowout event. If the pressure test causes any alteration at the failure location, that will be evident and can be distinguished from the original failure by fractography. The planned integrity/pressure tests serve objectives related to the Plugging and Abandoning (P&A) operations as well as data collection for the investigation. The casing test pressures are considered nominal, not greater than the design pressure.

8.2 Other Considerations

8.2.1 Mechanical Pipe Cutter

The Baker Mechanical Pipe Cutter is recommended to minimize damage to the tubing and the casing because it provides a safe and effective method to cut the tubing. As shown in Figure 38, the tubing cut with Baker Mechanical Pipe Cutter is smooth and uniform. The OD of the tubing at the location of the cut has not changed as a result of the cut. Tim Burger, with Baker Hughes explains why damaging the 7" is almost impossible:

With the monitoring functions of our software (ECLIPS), we can determine the exact moment of the tubing cut in real-time, using voltage, current, accelerometer and radius measurements coming from the cutter downhole. Tool can then be powered down immediately, resulting in the high-probability that the blade never comes into contact with the outer string. If contact is made with the 7" casing, it would be very momentary, resulting in only a scratch of the surface. Even if the tubing is ecentralized (eccentric) and touching the outer string at the point where the cut is made, a deep cut into the outer-string would be almost impossible, as the tool is only designed to cut a maximum casing size of 4" OD, and will be anchored to the tubing string at the time, NOT to the outer string. Again, once the cut is made, it will be very obvious from the surface readings.

Figure 38. Tubing Cut with the Baker Mechanical Pipe Cutter

8.2.2 Lost Circulation Material (LCM) to Cure Losses

In order to protect the surface of the breach, LCM without any solids will be used here. Typical LCM is "*solid* material intentionally introduced into a mud system to reduce and eventually prevent the flow of drilling fluid into a weak, fractured or vugular formation. This material is generally fibrous or plate-like in nature, as suppliers attempt to design slurries that will efficiently bridge over and seal loss zones. In addition, popular lost circulation materials are low-cost waste products from the food processing or chemical manufacturing industries. Examples of lost circulation material include ground peanut shells, mica, cellophane, walnut shells, calcium carbonate, plant fibers, cottonseed hulls, ground rubber, and polymeric materials."[ii]

[ii] Schlumberger Online Glossary, http://www.glossary.oilfield.slb.com/Terms/l/lcm.aspx

Circulation of fluids with abrasive solids through the 2-7/8" tubing by 7" casing or 7" casing by 11-3/4" casing maybe potentially damaging to evidence. The LCM can affect the recovery of the 7" casing by forming a bridge, akin to cement, and may not allow the casing to pull free. Additionally, the LCM can scour or abrade any remaining failure surfaces. The use of solids containing or cement-like LCM is not planned. Consequently, a solids-free gel-like LCM approach will be used to ensure there is no risk of sticking the production casing or cause any form of scouring of the breach region. Tests were performed with products such as Xanthan gum (also known as XC polymer), hydroxyethyl cellulose (HEC), cross-linked polymers, gunk plugs (mineral oil and bentonite), etc., to confirm the behavior of the solids free LCM. It is recognized that a solids-free LCM may not be as effective compared to using solids, but a solids-free approach will minimize damage to evidence.

8.3 Phase 3 Operational Concept Description

This section describes the base case conceptual plan for extracting the tubulars from SS-25 and then permanently abandoning the well. The base case is intended to provide the foundation for the initial planning for Phase 3 which includes identifying the equipment, tools and services, evaluating the major risks and potential problem areas, communicating the concept and objectives to the various stakeholders, and developing the initial operation procedures. The base case includes four separate and discrete sub-phases: Phase 3-A, Phase 3-B, Phase 3-C, and Phase 3-D. As shown in the summary procedure steps in Sections 9.1, 9.2, 9.3, 9.4 and 9.5, there are several statements of "Stop Operations" where new information gathered from previous operations will be accessed and evaluated prior to proceeding with the next operation. In addition, after completion of each sub-phase, Blade will stop operations and re-assess protocols and procedures; including: performing HAZid analysis, identifying mitigations, and confirming or revising decision trees and contingencies based on new information and circumstances. Any revisions, and any supplemental protocols will be submitted to the CPUC, DOGGR and SoCalGas for review, comment, and approval. The following steps reflect the need to be able to reenter the well sometime in the future after it has been permanently abandoned, per DOGGR regulatory requirements.

8.3.1 Phase 3-A: Pre-rig Steps, Place Cement and Set a Bridge Plug in the Tubing

As illustrated in Figure 39, the objectives of this stage are to complete pre-rig steps including determining the fluid levels in the tubing, 'A' annulus and 'B' annulus for information and planning purposes, and recover tubing fluid samples. Cement will be placed in the bottom of the tubing up to the TOC in the 'A' annulus. A bridge plug will be set in the tubing at ~7,590 ft.

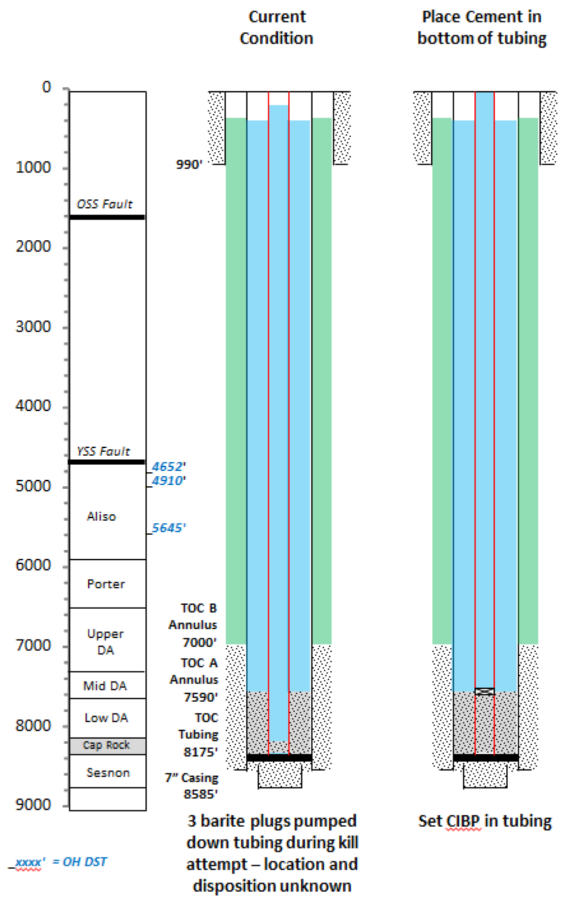


Figure 39. Determine Fluid Levels, Place Cement and Set a Bridge Plug in the Bottom of the Tubing

8.3.2 Phase 3-A: 2-7/8" Tubing Recovery and 7" Diagnostic Logging

As illustrated in Figure 40, the objectives of this stage are to recover the 2-7/8" tubing, inspect the casing at a depth of approximately 895' and run a suite of diagnostic logs in the 7" casing.

The steps include filling the annuli with mud, running a free point and cutting the tubing at the free point. If parted casing is not indicated, POH to 1050' and circulate to clear fluid and run a HD color video camera to inspect the 7" casing at a depth of approximately 895'. Displace the clear fluid back to mud to run the 7" casing logging program. The mud will be displaced to clear fluid for running the video camera at the end of the logging program.

The goals of the diagnostic logs (reference Table 13) are to better define the condition of the casing, understand the condition of the 7" by open hole annulus, and evaluate the formation lithology.

After logging the 7" casing, the plan is stop operations and review the log results and obtain approval for the next steps.

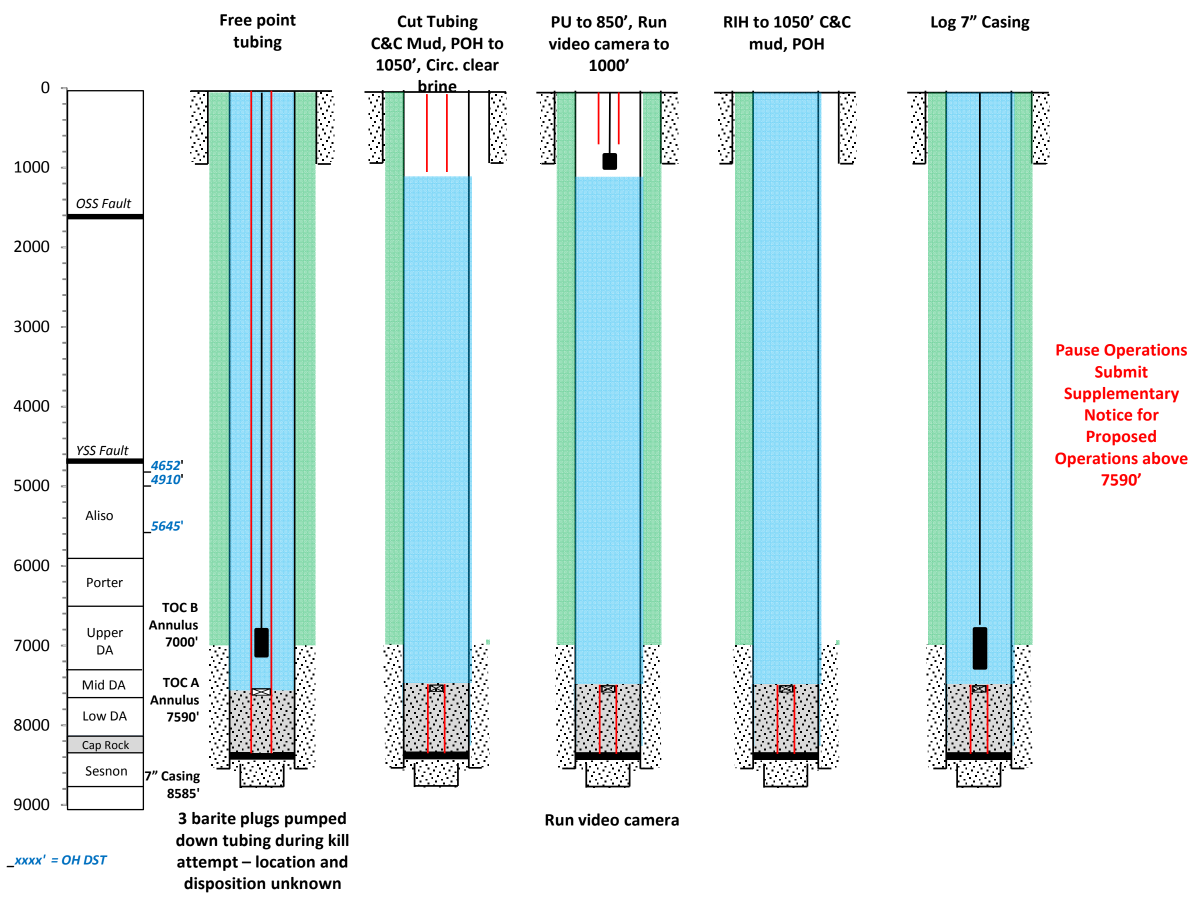


Figure 40. 2-7/8" Tubing Recovery and 7" Diagnostic Logging Sequence

The log results will determine the proposed next steps and may include setting plugs above the tubing stub, pressure test the bottom plugs and locate leaks in the 7" casing using a test packer. This may be followed by perforating and squeeze cementing multiple zones in the lower part of the well for the permanent P&A. The wellbore sequence steps are shown in Figure 41.

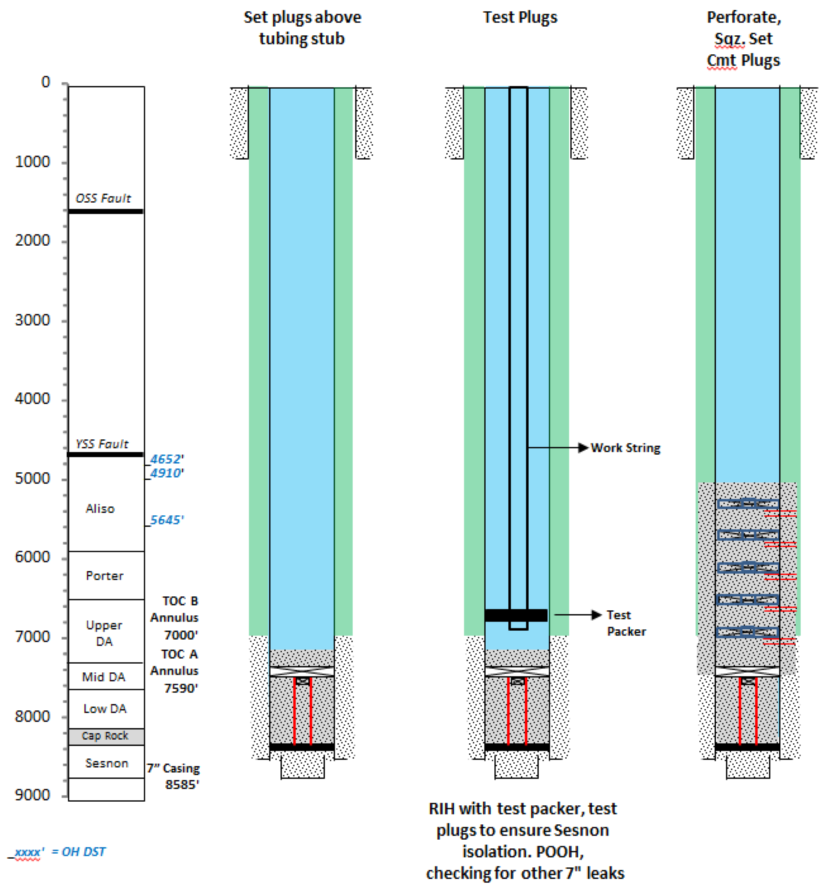


Figure 41. Set Plugs, Test Plugs, Perforate, Squeeze and P&A Lower Zones

8.3.3 Phase 3-A: Continency: Recover Parted 7" Casing and Log 11-3/4" Casing

Phase 3-A Contingency includes steps to proceed if there are indications of parted 7" casing. If the tubing is stuck it will be free pointed and cut above the free point and pulled. The 7" casing will be recovered to the cut tubing depth if above 930 ft. If the cut depth is deeper than 930 ft the casing will be cut at 930ft and recovered. The 11-3/4" casing will be logged in preparation for the next phase.

If the tubing is not stuck and is pulled, as shown in the right side of Figure 42 a gauge ring will be run to determine the casing part depth. The 7" casing may be logged prior to pulling the upper casing depending on the depth of parted casing. The 7" casing will be recovered to 930 ft. The 11-3/4" casing will be logged in preparation for the next phase. The high level steps are shown in Figure 42.

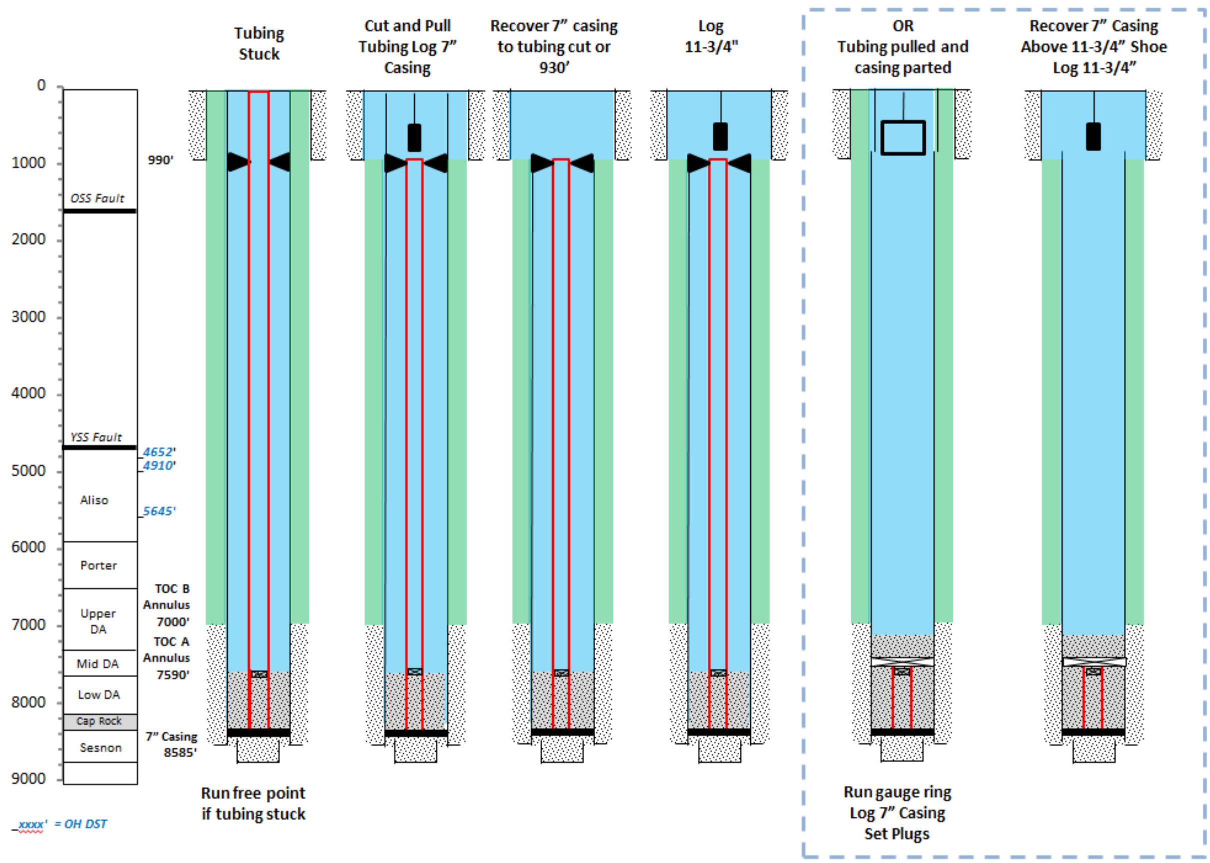


Figure 42. Recover Parted 7" Casing and 11-3/4" Logging

8.3.4 Phase 3-B: Upper 7” Casing Recovery and 11-3/4” Diagnostic Logging

If the 7” casing was pulled in Phase 3-A Contingency, skip Phase 3-B and go to Phase 3-C.

If Phase 3-A was completed, as shown in Figure 43, the plan is to recover the upper part of the 7” casing from just below the location of significant wall loss at 895 ft.

The wall loss location in the 7” casing is 95 ft above the 11-3/4” shoe. The nominal plan would be to recover the 7” down to ~930 ft leaving 75 ft of 7” inside the 11-3/4”. Recall that the current diagnostic log results for the 11-3/4” casing indicate significant wall loss at 151 and 192 ft. After the bottom part of the well is isolated, logging the 11-3/4” will allow additional confirmation of the condition of the 11-3/4” casing.

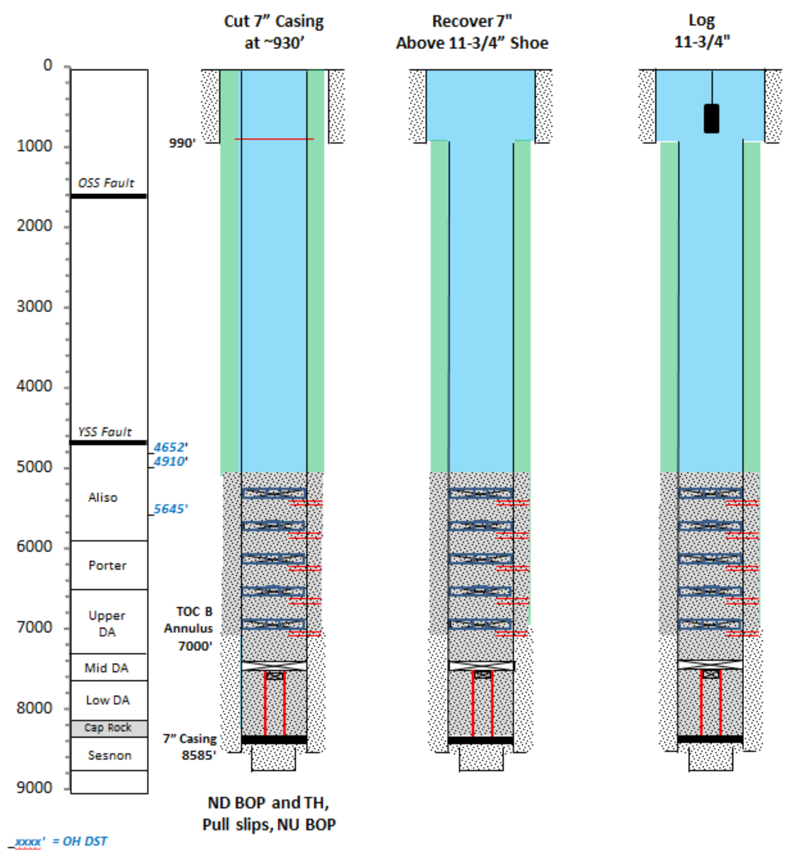


Figure 43. Upper 7” Recovery and 11-3/4” Logging Sequence

8.3.5 Phase 3-C: 11-3/4" Pressure Test and Repair

Phase 3-C will follow any combination of Phase 3-A, Phase 3-B and Phase 3-A Contingency.

As illustrated in Figure 44, an 11-3/4" RBP would be set as deep as possible to isolate the well so that the 11-3/4" can be evaluated and pressure tested. Repair the 11-3/4" casing leaks and pressure test to assure integrity of the surface casing. Repair options include an expandable casing patch or cement squeeze the 11-3/4" casing.

If Phase 3-A contingency steps were done, the perforate and squeeze cement plugs will be set later as part of the Phase 3-D steps.

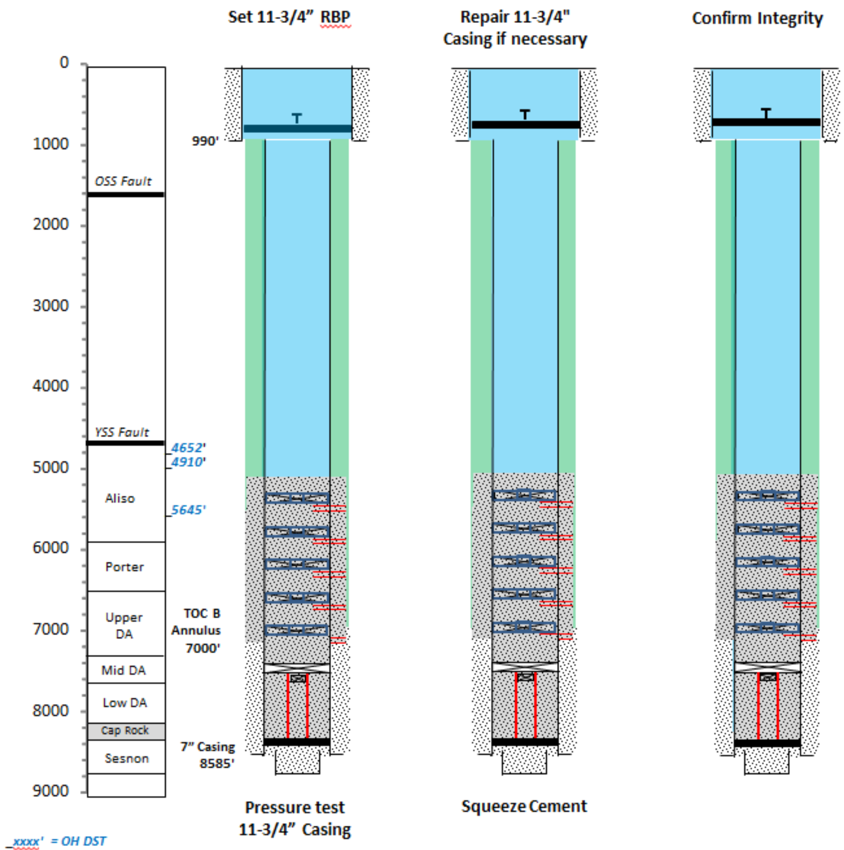


Figure 44. 11-3/4" Pressure Test and Repair

8.3.6 Phase 3-D: Recover Lower 7" Casing, Tieback and P&A

Phase 3-D will follow Phase 3-C if Phase 3-A and Phase 3-B were done or if Phase 3-A Contingency with free tubing was done.

After retrieving the 11-3/4" bridge plug, run a 7" temporary tieback casing for the purpose of perforating and squeezing the lower zones if not done previously. The 7" casing below the 11-3/4" shoe may be recovered based on log evaluation and the feasibility of recovering casing.

The 7" will then be tied back to surface and cemented. Perforate and squeeze the BFW zone to protect fresh water if required. The 7" tieback casing minimum requirements are 23 ppf J-55 or K-55 grade with a burst rating of 4,360 psi. The tieback casing will be pressure tested to ~1,000 psi. With the 7" casing tied back to surface, the SS-25 well can be P&A'd in a conventional manner which would also allow the well to be reentered should it become necessary sometime in the future. The high level steps are shown in Figure 45.

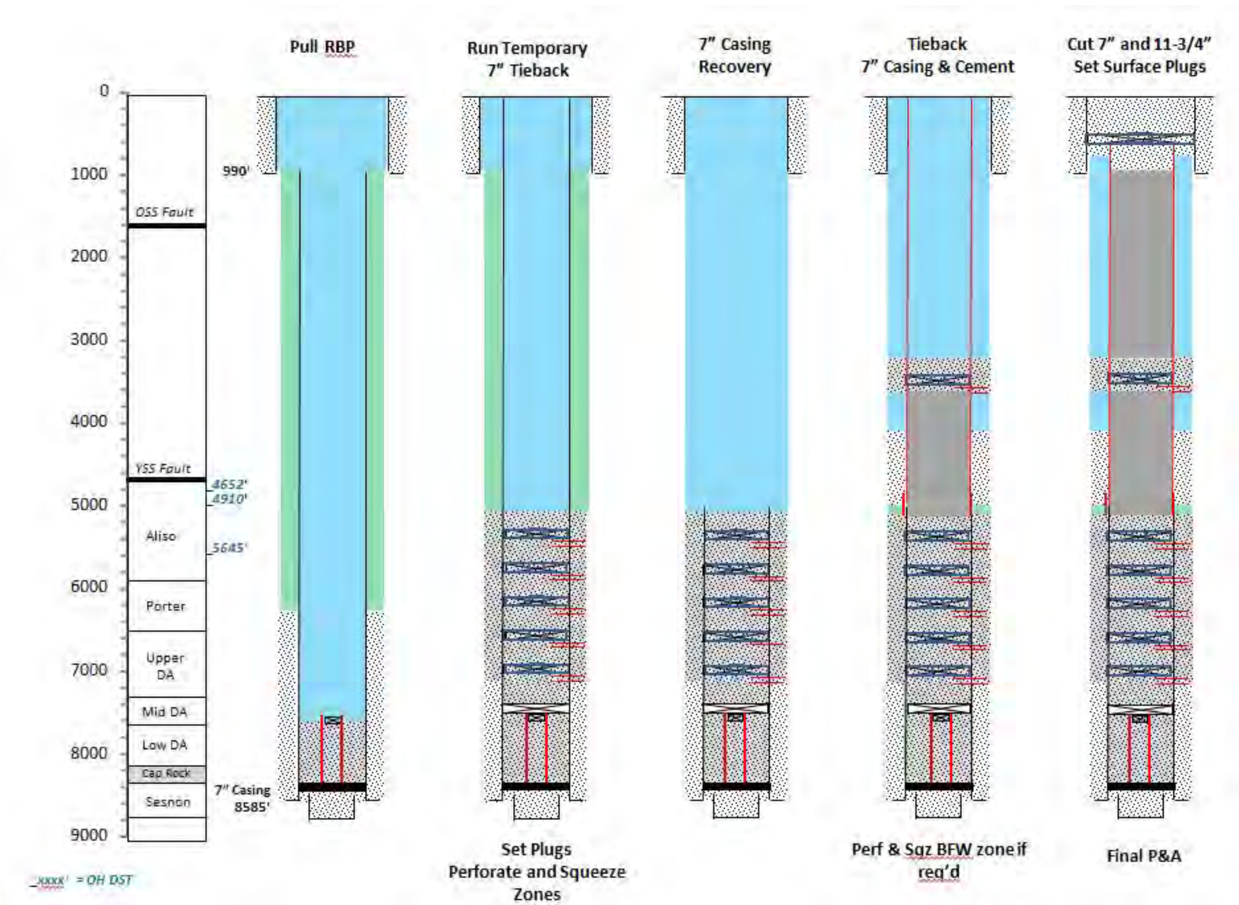


Figure 45. Lower 7" Recovery, Tieback and P&A Sequence

8.3.7 Phase 3-D Modified: Tieback 7" Casing for Fishing and Logging, Recover Lower Tubing, Log Lower 7" Casing, Recover Lower 7" Casing, Tieback 7" Casing and P&A Well

These contingency steps follow Phase 3-C and apply in the event the 7" is parted, the tubing was stuck and the upper 7" was recovered during the Phase 3A Contingency steps.

The 7" casing will be tied back temporarily for tubing recovery and for 7" casing logging. Following logging, perforate and squeeze the lower zones for abandonment. 7" casing may be recovered below the 11-3/4" casing shoe depending on log evaluation and feasibility of recovering casing.

After the 7" casing is recovered, the 7" casing will be tied back for P&A re-entry purposes. Perforate and squeeze the BFW zone to protect fresh water if required. The 7" tieback casing minimum requirements are 23 ppf J-55 or K-55 grade with a burst rating of 4,360 psi. The tieback casing will be pressure tested to ~1,000 psi. The high level steps are shown in Figure 46.

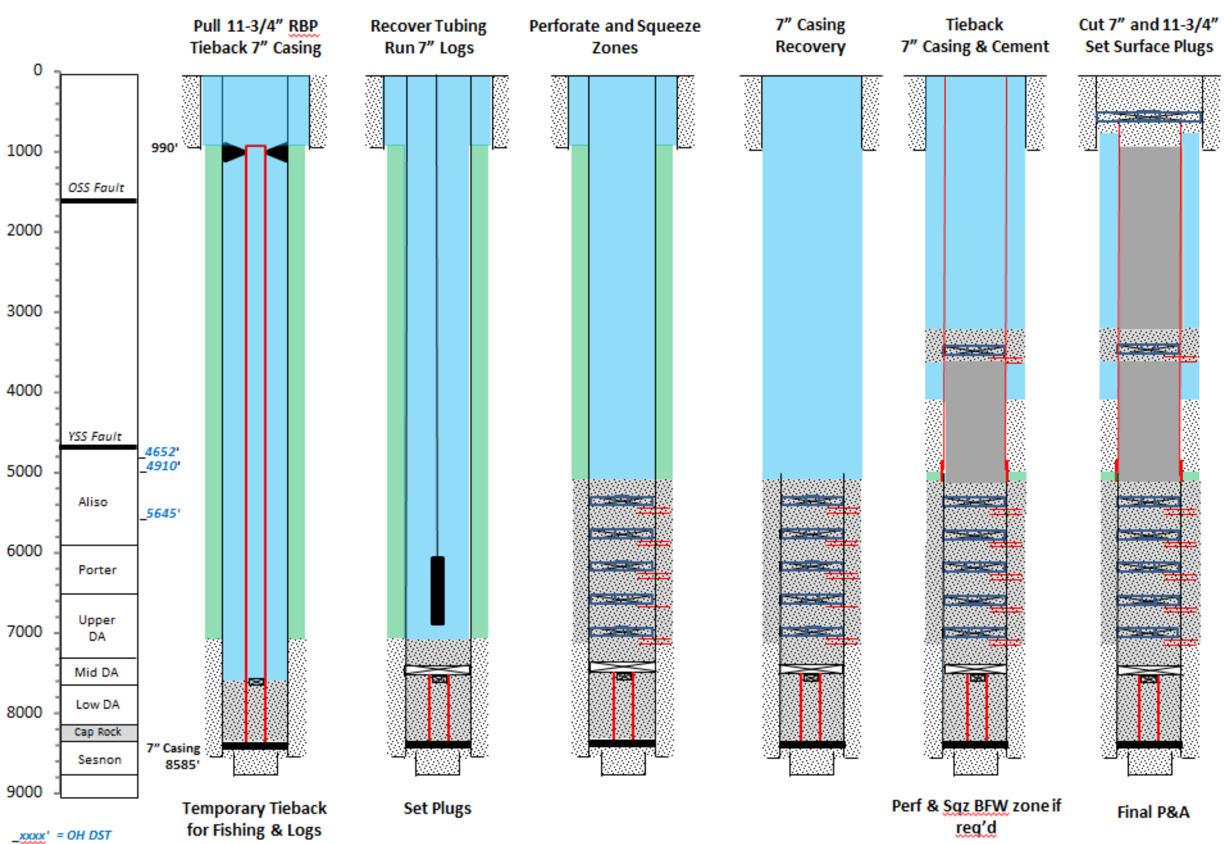


Figure 46. Tubing Recovery, Logging, 7" Recovery, Tieback and P&A Sequence

8.4 Casing Recovery Methods

The two methods for recovering casing are to wash over it, or to cut and pull it. Washing over allows the annulus to be circulated, provides confidence that the annulus is clear of solids, and that the washed over section is free. However, washing over has limitations such as how fast the wash shoe wears and must be tripped, the number of wash pipe joints that are practical, etc. There are also few options for fishing wash pipe should it become stuck. Usually there is no way to wash over stuck wash pipe due to OD and ID constraints, and the well would need to be P&A'd at this point. Additionally, there is a high potential for damaging the casing and/or the connections during the wash over process. Cutting and pulling the casing minimizes the potential for damaging the casing and connections, and can allow the recovery of longer sections of free pipe. However, additional trips may be required to circulate and condition the hole, and shallower cuts are needed if the casing is stuck thereby recovering shorter sections of casing.

The base case plan will be to start with the cut and pull method and have the wash over tools available as a backup. Being able to examine the casing in its current condition is important for the RCA.

Section 8.5 shows an overview of the risks associated with the extraction operations and steps that will be taken to mitigate the risks. Section 8.6 has several decision tree / contingency plans for the major steps of the operation.

As previously mentioned, the conceptual plans outlined in this section are based on what is known and suspected about the current condition of the well.

8.5 Phase 3 Potential Risks and Mitigation Steps

The following is a summary of some of the potential risks associated with each phase of the extraction process as well as the risk mitigation steps that will be taken. A detailed HAZid was completed, and appropriate mitigations are addressed.

Table 12. Potential Risk and Mitigation Steps

Risks	Consequence	Mitigations
2-7/8" Tubing Recovery		
Compromised Tubing Integrity (corrosion, collapse…)	Extended Fishing Time	•Evaluate diagnostic logs to determine tubing condition •Develop appropriate operating procedures
3 Barite plugs pumped during initial kill attempts	2-7/8" stuck inside 7", additional complexity pulling tubing	•Wash over and recover tubing
Compromised 7" integrity (collapse)	Inability to recover all the tubing string, limited 7" recovery	•Evaluate diagnostic logs to determine casing condition •Design ops plans to maximize recovery of both strings

Risks	Consequence	Mitigations
Losses while circulating or filling the tubing or casing	Unable to keep the hole full	•Mix and pump LCM pills •Run temperature survey to determine loss depth •Monitor well for safety. Proceed with work when the well is deemed safe
7" Casing Recovery		
11-3/4" Shoe Integrity	Lost Circulation, Mud Broaches to Surface	•Monitor for losses •Repair shoe with LCM
Long Open Hole Intervals During Recovery Ops *(SS-25 had 7595 ft of open hole before setting 7")*	Hole Stability: Hole collapse, washout, lost circulation, stuck pipe, additional fishing complexity, inability to proceed with recovery ops	•Develop lost circulation and fishing contingency plans •Rig selection, adequate pumps •Evaluate hole condition with cased hole logs
Not able to get over casing stub in open hole	Not able to recover additional casing to tie back casing, P&A the well	•Circ and condition mud •Wash and ream carefully to stay in original hole •Comprehensive pre-planning: historical data review, ops procedures, contingency planning
BHP in Water Flood Zone	Insufficient mud weight, well flows, hole stability	•Determine water flood BHP (static & operating). •Disallow WF operations, •Select appropriate mud density (P-39A drilled with 8.9 ppg mud)
Casing is stuck after 63 yrs	Limited recovery	•Run diagnostic logs as backup in case recovery is limited •Design ops plans to maximize recovery •Develop fishing contingency plans
11-3/4" Casing Integrity		
Casing leaks	Need to repair leaks for operations below the 11-3/4" casing	•Pressure test to confirm integrity •Repair casing for Phase 3 operations
Lost Circulation, Inability to keep hole full for well control	Hole Stability, Stuck Casing, Lost circulation, well flows	•Mix and pump LCM pills with no solids •Run temperature survey to determine loss depth •Monitor well for safety. Proceed with work when the well is deemed safe

8.6 Decision Trees and Contingencies

Decision trees for some of the critical operations are included below, and reflect the uncertainty in the current wellbore condition. There are many uncertainties that will exist until the procedure steps are executed. Examples of uncertainties include, lost circulation, parted casing, stuck casing, stuck tubing, etc. The purpose of the decision trees is to help communicate and understand the possible outcomes from operational decision points and to be prepared depending on the outcomes.

A summary of the key aspects of each decision tree is as follows:

- **Figure 47. Decision Tree: Fill 'A' Annulus with 9 ppg Mud**
  One of the first steps is to fill the 'A' annulus with 9 ppg mud. The volume of the 'A' annulus to 895 ft is 28 bbl. The bottom of the well is sealed with cement plugs. Therefore if there is a hole in the 7" casing it is possible that mud could be lost through the hole in the casing. As the decision tree shows, the 'A' annulus will be filled with 9 ppg mud. If the annulus stands full, the well will be ready for the next steps. If there are losses, the contingency is to mix and pump a lost circulation material (LCM) pill to plug the loss zone. High-vis LCM pills are recommended to minimize the risk of sticking the casing or tubing. If losses persist, steps such as monitoring the well fluid level to determine the loss rate and running a temperature log will be done to determine the depth of the loss zone. If it is not possible to cure the losses, the well will be monitored to determine when it is safe to proceed with operations to free point the tubing. The fluid level will be monitored to ensure the fluid level does not drop. Excess fluid will be added to the annulus to account for tubing pulled from the well.

  The tubing and cement plug in the tubing have been pressure tested. Therefore no losses are expected on the tubing side.

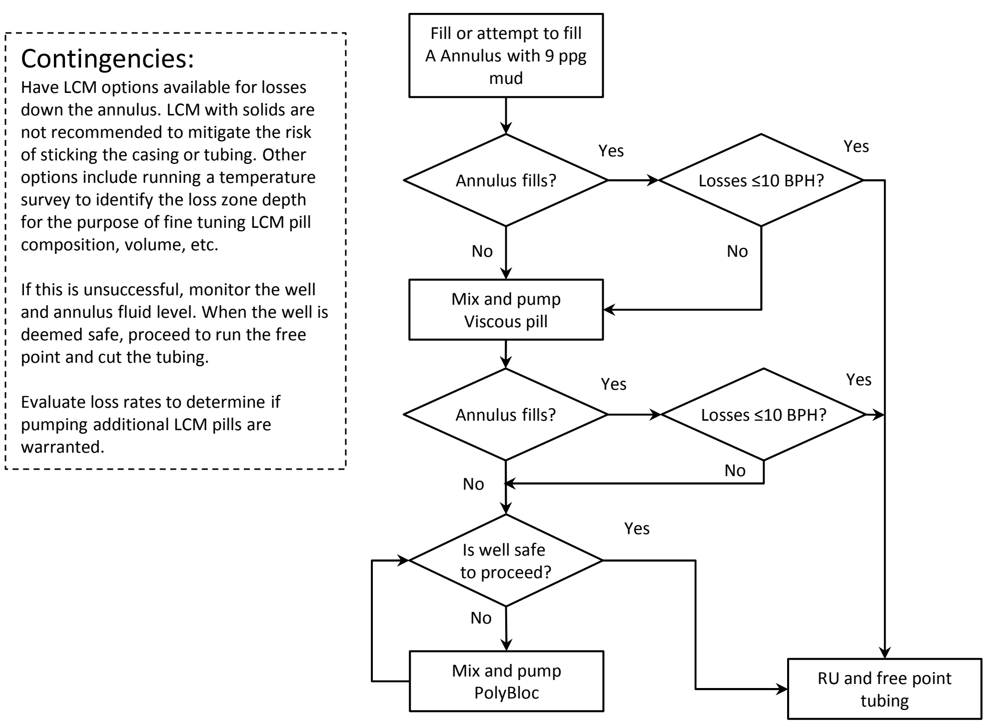


Figure 47. Decision Tree: Fill 'A' Annulus with 9 ppg Mud

- **Figure 48. Decision Tree: Cut and Pull Tubing and Log 7" Casing**

  The objective is to cut the tubing at the TOC in the 'A' annulus (~7,600 ft), displace to clear fluid and run a video camera prior to running other tools in the 7" casing. A free point tool will be run to determine the depth where the tubing is free. After the video camera is run, the clear fluid will be displaced back to mud for the remaining 7" casing log runs.

  The weight indicator will be monitored to determine if there are indications that the casing is parted and is causing drag while pulling tubing. The recommended maximum tension will be indicated in the work plan. If there are indications of parted 7" casing causing excessive tubing drag, pause operations for evaluation and next steps approval.

  If additional tubing needs to be recovered for P&A plugs, washpipe may be used to recover additional tubing. If this is successful, washing over the tubing will continue until sufficient tubing is recovered.

  If it appears there is parted casing or the parted casing prevents pulling the tubing, pause operations for evaluation and next steps approval.

  After 7" casing logs are run, perforate and squeeze the lower P&A zones.

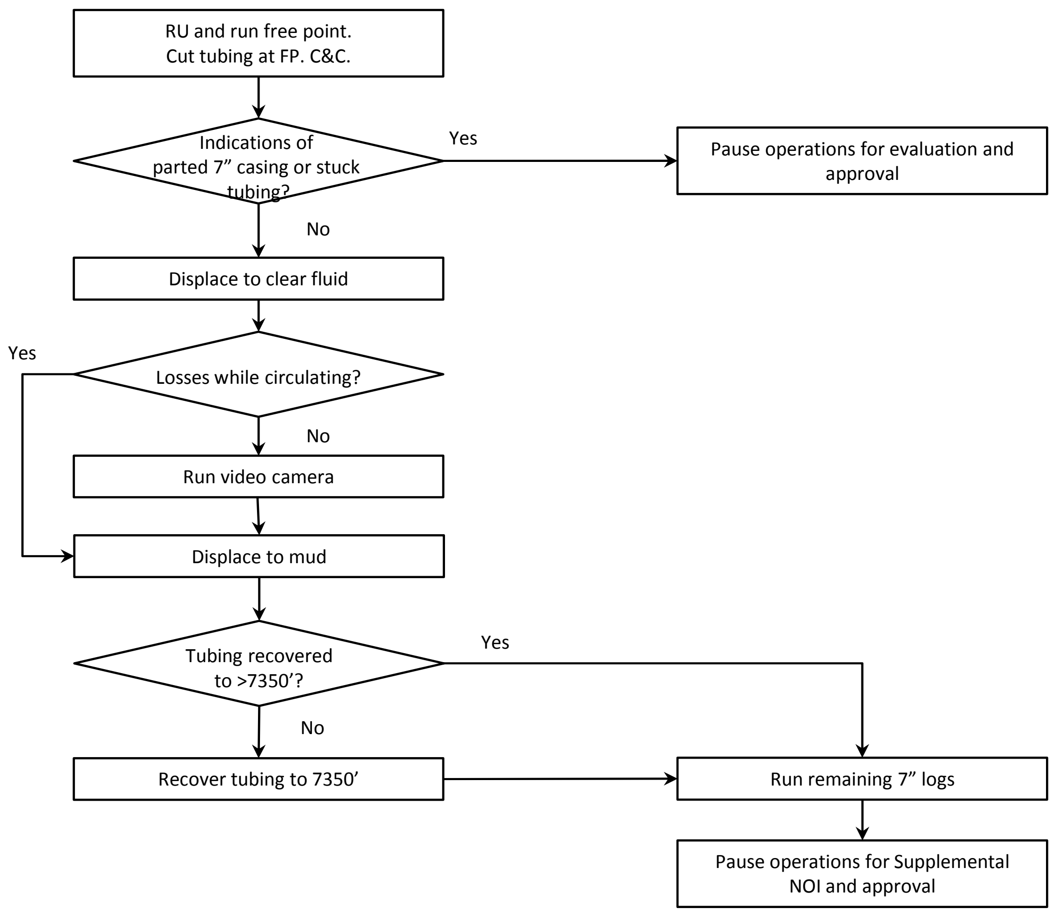


Figure 48. Decision Tree: Cut, Pull Tubing and Log 7" Casing

- **<u>Figure 49. Decision Tree: Recover Parted 7" Casing and Inspect 11-3/4" Casing</u>**
  This decision tree is associated with Phase 3-A Contingency where there are indications of parted casing causing tubing drag while POH.

  If the tubing can be pulled a gauge ring will be run to determine the depth of parted casing. Inspection logs will be run in the 7" casing to the part depth. If the part depth is deeper than the 11-3/4" shoe, the 7" casing will be recovered to ~930 ft. Then run 11-3/4" inspection logs.

  If the tubing cannot be pulled, run a free point, cut the tubing and recover the tubing to the free point. If the tubing is recovered below the 11-3/4" shoe, run 7" inspection logs to the cut depth. If the tubing cut depth is above the 11-3/4" shoe, recover the 7" casing to the tubing cut depth. Then run 11-3/4" inspection logs.

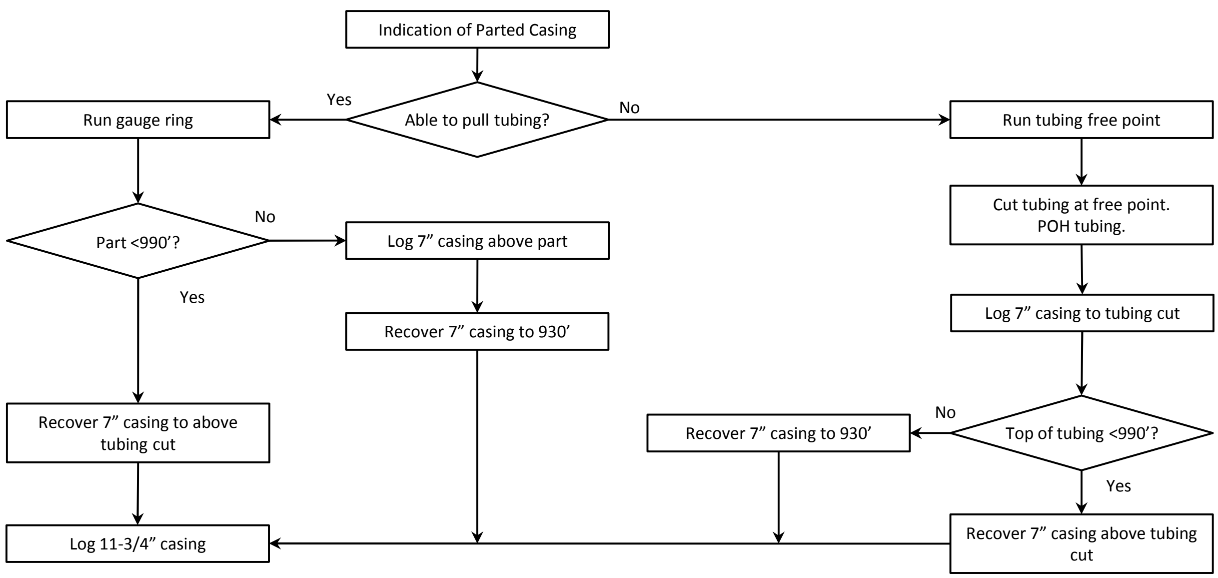


Figure 49. Decision Tree: Recover Parted 7" Casing and Inspect 11-3/4" Casing

9 Operational Procedures Executive Summary

A high level summary for Phase 3 is shown in Figure 50.

SS-25 RCA Phase 3-A

Phase 3-A Pre-Rig Tasks
Pressure test B annulus valve
Shoot fluid level A and B annuli
Shoot fluid level in tubing
Take tubing fluid samples. Place cement and CIBP in the bottom of the tubing.

Phase 3-A Rig (Recover tubing, Log 7" casing)
Fill A and B annuli. Shoot levels, consider High-Vis LCM pills for losses
IF annulus stands full
Set BPV, ND tree, NU BOP, Pull BPV
ELSE Cure losses, Set BPV. ND tree, NU BOP. Pull BPV.
Free point tubing
Cut tubing at 7590'. If there is tubing drag indicating parted 7" casing, consider setting a cement plug above the tubing stub.
IF parted casing is not indicated, circulate to clear fluid. Run HD color video camera.
POH LD tubing
OR
Cut tubing <7590'
IF there are indications of parted casing (1)
Stop Operations; Obtain approval for next steps
IF parted casing is not indicated, circulate to clear fluid. Run HD color video camera.
Recover tubing to 7350'
Log 7" casing. Evaluate logs.
Stop Operations; Obtain approval for next steps
Set BP and/or cement plug
RIH test packer and test bottom plug
Test 7" casing for upper leaks
Perforate and squeeze zones at ~7350' MDA, ~6550' UDA, ~6250' LP
Perforate and squeeze zones at ~5800' UP, ~5500' A36, ~4600' A1

(1) Indications of parted 7" casing include high drag when pulling tubing or couplings that hang up.

Phase 3-A Contingency (Recover parted 7" casing and log 11-3/4" casing)
IF Tubing Free
POH with tubing. Run Gauge Ring.
-IF 7" Parted above 11-3/4" Shoe
Extended flow check
ND BOP and TH. Pull slips. NU BOP.
Recover 7" casing to 930'
Log 11-3/4" casing →
-IF 7" Parted below 11-3/4" Shoe
Log 7" casing to parted depth
Cut 7" casing at 930'
Extended flow check
ND BOP and TH. Pull slips. NU BOP.
Recover 7" casing to 930'
Log 11-3/4" casing →
ELSE Tubing Stuck
Run free point. If stuck off bottom, RIH to bottom. Cut tubing.
POH with tubing.
-IF Recover tubing above 990'
Log 7" casing to cut tubing depth
Cut 7" casing at tubing cut
Extended flow check
ND BOP and TH. Pull slips. NU BOP.
Recover 7" casing to tubing cut
Log 11-3/4" casing →
-IF Recover tubing below 990'
Log 7" casing to tubing cut
Cut 7" casing at 930'
Extended flow check well.
ND BOP and TH. Pull slips. NU BOP.
Recover 7" casing to 930'
Log 11-3/4" casing →

Phase 3-B (Recover 7" casing to 930' and log 11-3/4" casing)
Cut 7" casing at ~930'
Set storm pkr. ND BOP and TH. Pull slips. NU BOP. Pull storm pkr.
POH and LD casing
Log 11-3/4" casing →

Phase 3-C (Restore integrity to 11-3/4" casing)
Set 11-3/4" RBP
Test 11-3/4" casing for leaks
Repair casing leaks
IF Phase 3-A & 3-B done OR Phase 3-A Contingency and tubing free, GOTO Phase 3-D
IF Phase 3-A Contingency was done and tubing stuck, GOTO Phase 3-D Modified

Phase 3-D (Recover lower 7" casing, tieback 7" casing, P&A well)
POH 11-3/4" RBP
Run temporary 7" tieback if required for perforate and squeeze
If not done previously: Set BP and/or cement plug
If not done previously: RIH test packer and test bottom plug
If not done previously: Perforate and squeeze zones at ~7350' MDA, ~6550' UDA, ~6250' LP
If not done previously: Perforate and squeeze zones at ~5800' UP, ~5500' A36, ~4600' A1
Recover 7" casing below 990' as required for the RCA
Tieback 7" casing and cement
Cut 7" casing above 11-3/4" shoe
ND BOP. ND TH.
Set cement plugs
Cut surface casing
Set surface cement plugs

Phase 3-D Modified (Tieback 7" casing, Recover lower tubing, Log lower 7" casing, Recover 7" casing, Tieback 7" casing, P&A well)
POH 11-3/4" RBP
Run temporary 7" tieback
ND BOP, NU tubing head, NU BOP
Recover tubing
Log lower 7" casing. Evaluate logs.
Set BP and/or cement plug
RIH test packer and test bottom plug
Perforate and squeeze zones at ~7350' MDA, ~6550' UDA, ~6250' LP
Perforate and squeeze zones at ~5800' UP, ~5500' A36, ~4600' A1
Recover 7" casing below 990' as required for the RCA
Tieback 7" casing and cement
Cut 7" casing above 11-3/4" shoe
ND BOP. ND TH.
Set cement plugs
Cut surface casing
Set surface cement plugs

From file:

SS-25 Phase 3 Summary Steps Rev 10.xlsx

Figure 50. High Level Summary of Phase 3-A, 3-A Contingency, 3-B, 3-C, 3-D and 3D Modified

A high-level contextual summary of the operational steps of the extraction procedure is provided below.

9.1 Phase 3-A: Recover 2-7/8" Tubing and Inspect 7" Casing

9.1.1 Phase 3-A Pre-Rig Tasks

1. Pressure test the 2"-3000 psi threaded 'B' annulus valve.
2. Remove the DTS from SS-25
3. Shoot the fluid level in the 'A' annulus and 'B' annulus
4. Shoot the fluid level in the tubing
5. Recover tubing fluid samples using a wireline fluid sampler device
6. Place cement in the bottom of the tubing from ~8,175 ft to ~7,590 ft and tag cement
7. Set a bridge plug in the tubing above the TOC at ~7,590 ft

9.1.2 Phase 3-A Rig Tasks

8. MIRU the rig
9. Fill the tubing and A annulus with 9.0 ppg mud
    a. If the annulus stands full, proceed to set a BPV.
    b. If the annulus does not fill, mix and pump LCM with no solids, monitor the well and fluid level. When the well is safe, go to the step to set a BPV.
10. Set a BPV in the tubing hanger. ND tree and tubing head adaptor.
11. NU BOPE with a 6" diverter. Pull the BPV. Test the BOPE and function test the diverter.
12. MU landing joint in tubing hanger
13. RU wireline lubricator
14. Run a free point and CCL to determine the free point of the tubing (the estimated TOC in the annulus is 7,590 ft based on the CBL log included in Section 15)
15. If the tubing is free at ~7,590 ft, cut the tubing. C&C mud.
    a. POH and lay down ~5 joints of tubing, noting if there is excess drag, indicating possible parted casing.
    b. If possible parted casing <u>is</u> indicated, <u>Stop Operations</u>. Assess the feasibility and need to set a cement plug above the tubing stub prior to POH with the tubing. Considerations include running tubing back to bottom; evaluate the need to set a cement plug prior to POH, squeeze cement, etc. The next steps will be prepared and regulatory and other approvals will be obtained prior to any next step operations.
    c. If parted casing <u>is not</u> indicated, POH to 1050'. Lay down tubing per the protocol procedures. <u>Circulate the well with clear fluid in preparation to running a HD color video camera.</u> POH to 850'. RU and run the camera to inspect the 7" casing in the area of 895'. RD eline. RIH to 1050' with spare joints. Displace the clear fluid with mud.

16. If the tubing is free above ~7,590 ft, cut the tubing at the free point. C&C mud.
    a. POH and lay down 6 joints of tubing, noting if there is excess drag, indicating possible parted casing.
    b. If parted casing is indicated, Stop Operations. Considerations include the depth of parted casing and the need to recover tubing deep enough to properly P&A the well. The next steps will be prepared and regulatory and other approvals will be obtained prior to any next step operations.
    c. If parted casing is not indicated, POH to 1050'. Lay down tubing per the protocol procedures. Circulate the well with clear fluid in preparation to running a HD color video camera. POH to 850'. RU and run the camera to inspect the 7" casing in the area of 895'. RD eline. RIH to 1050' with spare joints. Displace the clear fluid with mud.
    d. Recover the tubing to ~7,350 ft.
17. RU wireline and make the 7" logging runs and evaluate logs
18. Stop operations, evaluate next steps and obtain approval for next steps.
19. Set a bridge plug and/or cement plug above the tubing stub
20. RIH with test packer to pressure test the bottom plug and locate casing leaks
21. Based on the results of CBL, isolate the Middle Del Aliso sand (top at ~7,350 ft). Lay a cement plug from ~7,350 ft to ~7,200 ft if there is good isolation on the CBL, or perforate the MDA at ~7,350 ft, establish injection, set a cement retainer above and squeeze the zone and then lay a 100-150 ft cement plug on top of the retainer. If unable to inject, balance a cement plug in the casing.
22. Perforate, establish injection, set a cement retainer, and squeeze the zone at ~6,550 ft to isolate the Upper Del Aliso sand for the P&A. Place 150 ft of cement above the retainer. If unable to inject, balance a cement plug in the casing.
23. Perforate, establish injection, set a cement retainer, and squeeze the zone at ~6,250 ft to isolate the Lower Porter sand for the P&A. Place 150 ft of cement above the retainer. If unable to inject, balance a cement plug in the casing.
24. Perforate, establish injection, set a cement retainer, and squeeze the zone at ~5,800 ft to isolate the Upper Porter sand for the P&A. Place 150 ft of cement above the retainer. If unable to inject, balance a cement plug in the casing.
25. Perforate, establish injection, set a cement retainer, and squeeze the zone at ~5,500 ft to isolate the A36 sand for the P&A. Place 150 ft of cement above the retainer. If unable to inject, balance a cement plug in the casing.
26. Perforate, establish injection, set a cement retainer, and squeeze the zone at ~4,650 ft to isolate the A1 sand for the P&A. Place 150 ft of cement above the retainer. If unable to inject, balance a cement plug in the casing.
27. Stop operations, evaluate next steps and obtain approval for next steps.
28. Prepare for Phase 3-B

9.1.3 Phase 3-A Contingency Tasks

These contingency steps apply if there are indications the 7" is parted.

29. If the tubing is free, POH with the tubing
    a. RIH with gauge ring to check for parted casing depth.
    b. If the 7" casing is parted above 990 ft, ND BOP and tubing head. Pull casing slips. NU BOP. Recover the 7" casing to ~930 ft. Log the 11-3/4" casing.
    c. If the 7" casing is parted below 990 ft, log the 7" casing to the parted casing depth. Cut the 7" casing at 930 ft. ND BOP and tubing head. Pull casing slips. NU BOP. Recover the 7" casing. Log the 11-3/4" casing.
    d. Prepare for Phase 3-C and Phase 3-D
30. If the tubing is stuck, free point the tubing. If the tubing is stuck off bottom, attempt to run the tubing back to bottom. Cut the tubing above the stuck point. POH tubing.
    a. If the tubing is cut above 990 ft, log the 7" casing above the cut depth. Cut or pull the 7" casing at the tubing cut depth. ND BOP and tubing head. Pull casing slips. NU BOP. Recover the 7" casing to the tubing cut depth. Log the 11-3/4" casing.
    b. If the tubing cut is below 990 ft; log the 7" casing above the cut depth. Cut the 7" casing at 930 ft. ND BOP and tubing head. Pull casing slips. NU BOP. Recover the 7" casing. Log the 11-3/4" casing.
    c. Prepare for Phase 3-C and Phase 3-D Modified
31. Stop operations, evaluate next steps and obtain approval for next steps.

9.2 Phase 3-B: Recover the 7" Casing to 930 ft

If the 7" casing was pulled in Phase 3-A Contingency. Skip Phase 3-B and go to Phase 3-C.

32. RIH casing cutter and cut the 7" casing at ~930 ft (above the 11-3/4" shoe)
33. Set a storm packer at 200 ft
34. ND the BOP
35. ND the tubing head and DSA to expose the 7" casing slips and pack-off
36. Pull casing slips
37. NU BOP on the 13-5/8" 5M casing head flange
38. Retrieve the storm packer
39. Run a spear on 3-1/2" work string
40. POH laying down the 7" casing per the protocol procedures
41. Run 11-3/4" inspection logs
42. Stop operations, evaluate next steps and obtain approval for next steps.

9.3 Phase 3-C: Pressure Test and Repair 11-3/4" Casing

Phase 3-C will follow any combination of the previous phases.

43. Set an 11-3/4" RPB above the 7" casing stub
44. Pressure test the 11-3/4" to 500 psi. Locate any leaks.
45. Leaks may be repaired several methods including cement squeeze or expandable casing patch. If there are leaks, the repair method will be based on 11-3/4" casing log evaluation.
46. Confirm the pressure integrity of the 11-3/4" casing by pressure testing to 500 psi with 9 ppg fluid
47. Prepare for Phase 3-D or Phase 3-D Modified
48. Stop operations, evaluate next steps and obtain approval for next steps.

9.4 Phase 3-D: Recover the Lower 7" Casing, Tie Back the 7" and P&A Well

Phase 3-D will follow Phase 3-C if Phase 3-A and Phase 3-B were done or if Phase 3-A Contingency with free tubing was done.

49. Pull the 11-3/4" RBP
50. Set a bridge plug and cement plug above the tubing stub (if not done previously).
51. RIH with test packer to pressure test the bottom plug.
52. Tieback 7" casing temporarily if required for perforate and squeeze for the P&A.
53. Based on the results of CBL, isolate the Middle Del Aliso sand (top at ~7,350 ft). Lay a cement plug from ~7,350 ft to ~7,200 ft if there is good isolation on the CBL, or perforate the MDA at ~7,350 ft, establish injection, set a cement retainer above and squeeze the zone and then lay a 100-150 ft cement plug on top of the retainer. If unable to inject, balance a cement plug in the casing.
54. Perforate, establish injection, set a cement retainer, and squeeze the zone at ~6,550 ft to isolate the Upper Del Aliso sand for the P&A. Place 150 ft of cement above the retainer. If unable to inject, balance a cement plug in the casing.
55. Perforate, establish injection, set a cement retainer, and squeeze the zone at ~6,250 ft to isolate the Lower Porter sand for the P&A. Place 150 ft of cement above the retainer. If unable to inject, balance a cement plug in the casing.
56. Perforate, establish injection, set a cement retainer, and squeeze the zone at ~5,800 ft to isolate the Upper Porter sand for the P&A. Place 150 ft of cement above the retainer. If unable to inject, balance a cement plug in the casing.
57. Perforate, establish injection, set a cement retainer, and squeeze the zone at ~5,500 ft to isolate the A36 sand for the P&A. Place 150 ft of cement above the retainer. If unable to inject, balance a cement plug in the casing.
58. Perforate, establish injection, set a cement retainer, and squeeze the zone at ~4,650 ft to isolate the A1 sand for the P&A. Place 150 ft of cement above the retainer. If unable to inject, balance a cement plug in the casing.
59. Stop Operations. Assess feasibility of recovering 7" casing below the 11-3/4" shoe based on log results. Obtain regulatory approval.
60. Cut and pull or wash over the 7" until sufficient casing is recovered

61. Tie back the 7” and cement
62. ND BOP. NU Tubing head. NU BOP
63. Perforate 7” tieback casing and squeeze the BFW zone for P&A (if required).
64. Cut the 7” casing above the 11-3/4” shoe
65. ND BOP. ND TH. Pull casing slips. NU BOP.
66. POH and LD casing.
67. Set a cement retainer and cement plug at the 7” stub
68. ND BOP. Cut the 11-3/4” below ground level or leave the casing head on for monitoring
69. Set the surface cement plug

9.5 Phase 3-D Modified: Tieback 7” Casing for Fishing and Logging, Recover Lower Tubing, Log Lower 7” Casing, Recover Lower 7” Casing, Tieback 7” Casing and P&A Well

These contingency steps apply following Phase 3-C in the event the tubing is stuck, the 7” is parted and the upper 7” was recovered during the Phase 3A Contingency steps.

70. Pull the 11-3/4” RBP.
71. Tieback the 7” casing temporarily for fishing tubing and logging purposes.
72. ND the BOP, Install tubing head, NU BOP.
73. Fish and recover tubing to ~7,350 ft.
74. Run 7” logs in lower 7” casing and evaluate logs.
75. Set a bridge plug and cement plug above the tubing stub (if not done previously).
76. RIH with test packer to pressure test the bottom plug.
77. Based on the results of CBL, isolate the Middle Del Aliso sand (top at ~7,350 ft). Lay a cement plug from ~7,350 ft to ~7,200 ft if there is good isolation on the CBL, or perforate the MDA at ~7,350 ft, establish injection, set a cement retainer above and squeeze the zone and then lay a 100-150 ft cement plug on top of the retainer. If unable to inject, balance a cement plug in the casing.
78. Perforate, establish injection, set a cement retainer, and squeeze the zone at ~6,550 ft to isolate the Upper Del Aliso sand for the P&A. Place 150 ft of cement above the retainer. If unable to inject, balance a cement plug in the casing.
79. Perforate, establish injection, set a cement retainer, and squeeze the zone at ~6,250 ft to isolate the Lower Porter sand for the P&A. Place 150 ft of cement above the retainer. If unable to inject, balance a cement plug in the casing.
80. Perforate, establish injection, set a cement retainer, and squeeze the zone at ~5,800 ft to isolate the Upper Porter sand for the P&A. Place 150 ft of cement above the retainer. If unable to inject, balance a cement plug in the casing.
81. Perforate, establish injection, set a cement retainer, and squeeze the zone at ~5,500 ft to isolate the A36 sand for the P&A. Place 150 ft of cement above the retainer. If unable to inject, balance a cement plug in the casing.

82. Perforate, establish injection, set a cement retainer, and squeeze the zone at ~4,650 ft to isolate the A1 sand for the P&A. Place 150 ft of cement above the retainer. If unable to inject, balance a cement plug in the casing.
83. Stop operations. Assess feasibility of recovering 7” casing below the 11-3/4” shoe based on log results. Obtain regulatory approval.
84. Cut and pull or wash over the 7” until sufficient casing is recovered
85. Tie back the 7” and cement
86. ND BOP. NU Tubing head. NU BOP
87. Perforate 7” tieback casing and squeeze the BFW zone for P&A (if required).
88. Cut the 7” tieback casing above the 11-3/4” shoe
89. ND BOP and tubing head. Pull casing slips. NU BOP.
90. POH and LD casing.
91. Set a cement retainer and cement plug at the 7” stub
92. ND BOP. Cut the 11-3/4” below ground level or leave the casing head on for monitoring
93. Set the surface cement plug

10 Equipment and Services Requirements

The following is a description of the third party equipment and services that will be required for the extraction operations.

10.1 Wireline Logging – Casing inspection Services

The Table 13 and Table 14 show a list of the wireline logging tools that are planned to run in the 7" and 11-3/4" to obtain as much information as possible on the condition of the casing prior to the casing recovery operations.

The downhole camera, Baker caliper and Versa-Line logs can be run before a casing scraper is run. The logs will be evaluated to determine the feasibility of running a casing scraper. A casing scraper run prior to running the remaining logs is preferable.

Table 13. 7" Casing Diagnostic Wireline Logging Program

Log Description	Purpose	Provider	Tool Name	Abbreviation
Downhole camera	Visual inspection of 7" casing ID at 895 ft	EV	EV Downhole Video	MK2
Junk Basket, Gauge Ring, Gamma Ray, Casing Collar Locator	Determine if there are any ID restrictions	Baker	--	JB-GR/GR/CCL
Mechanical Caliper	7" ID measurements, deformation, corrosion indications	Baker	ICAL Multi-Finger Caliper	ICAL
Defect detection-magnetic imaging	Metal loss detection - defect identification in the 7" and 11-3/4" casing	Versa-Line	Magnetic Imaging Defectoscope-2 Magnetic Imaging Defectoscope-3	MID 2 MID-3
Re-run ICAL after scraper run				
Defect detection-magnetic imaging	Metal loss detection in 7" - defect identification	Baker	High Resolution Vertilog	HRVRT
Formation Evaluation	Water saturation, Carbon / Oxygen ratio, Hydrogen Index, Presence of Gas	SLB	Pulsed Neutron eXtreme	PNX
Annulus evaluation 7" Casing condition	Solid-liquid-gas map of annulus material, hydraulic communication map, acoustic impedance, flexural attenuation, rugosity image, casing thickness image, internal radius image	SLB	Isolation Scanner	IBC
Annulus evaluation Formation evaluation	Cement bond quality, formation characterization, identification of open fractures	SLB	Sonic Scanner	SSCAN

Log Description	Purpose	Provider	Tool Name	Abbreviation
7" Casing condition Formation evaluation	High resolution ultrasonic casing ID and OD imaging; Lithology type, water, hydrocarbon identification	SLB	Ultrasonic Corrosion Imager, LithoScanner	UCI-NEXT
Active corrosion detection	Identify anodic/cathodic cells indicating active corrosion	SLB	Corrosion and Protection Evaluation Tool	CPET
Re-run Downhole camera	Visual inspection of 7" ID for defects and anomalies	EV	EV Downhole Video	MK2

Table 14. 11-3/4" Casing Diagnostic Wireline Program

Log Description	Purpose	Provider	Tool Name	Abbreviation
Junk Basket, Gauge Ring, Gamma Ray, Casing Collar Locator	Determine if there are any ID restrictions	Baker	--	JB-GR/GR/CCL
Mechanical Caliper	11-3/4" ID measurements, deformation, corrosion indications	Baker	ICAL Multi-Finger Caliper	ICAL
11-3/4" Casing condition	Metal loss detection - defect identification in the 11-3/4" casing and the depth of the 20" conductor	Versa-Line	Magnetic Defectoscope-2	MID-2
Formation Evaluation	Water saturation, Carbon / Oxygen ratio, Hydrogen Index, Presence of Gas	SLB	Pulsed Neutron eXtreme	PNX
Annulus evaluation 11-3/4" Casing condition	Solid-liquid-gas map of annulus material, hydraulic communication map, acoustic impedance, flexural attenuation, rugosity image, casing thickness image, internal radius image	SLB	Isolation Scanner	IBC
Annulus evaluation Formation evaluation	Cement bond quality, formation characterization, identification of open fractures	SLB	Sonic Scanner	SSCAN
11-3/4" Casing condition Formation evaluation	High resolution ultrasonic casing ID and OD imaging; Lithology type, water, hydrocarbon identification	SLB	Ultrasonic Corrosion Imager, LithoScanner	UCI-NEXT
Downhole camera	Visual inspection of 11-3/4" ID for defects and anomalies	EV	EV Downhole Video	MK2

10.2 Fishing Tools Services

A preliminary list of fishing tools required to recover the 2-7/8" and 7” strings is provided below.

Table 15. List of Fishing Tools

Item no.	Tool Description
	For the 2.875" Tubing Recovery Above 2.875" Freepoint
1	Overshot with Mill Control and Cut Lip Guide dressed with grapple for 2.875" body of pipe and additional Grapple for Coupling OD
2	Bowen Oil Jars for fishing not drilling
3	Accelerator Jars
4	Bumper Sub
5	TIW Valve
6	Elevators and Slips for 2-7/8”
7	Burn shoe for dressing off stub if needed
8	Power Swivel (or rig top drive) for all operations and may need to change out to larger units as pipe weight and size of fish increases.
	For the 2.875" Tubing Recovery Below 2.875" Freepoint
9	Same list as above plus the following
10	Wash pipe with bushing and crossovers for workstring
11	Wavy bottom Burning shoes to wash over fish and couplings
12	Overshot with Pack-off for recovery/ wireline jet cutter operations
13	Possible outside cutter
	For 7" Recovery Above Freepoint
14	Multiple Bit sizes to drift casing through bad spot and to depth of recovery
15	Casing Swages to open casing to drift sufficient to allow inside cutter or jet cutter pass through
16	Spear with basket or spiral grapple with stop and maybe packoff for lifting the 7" to pull slips and packoff assembly
17	Grapple extension if needed
18	Bumper Sub
19	Wireline Jet cutter
20	Inside Cutter with short Knives for cutting stub below wellhead
21	Jars
22	Accelerator jars
23	Casing Jacks and support equipment for ground for flange mounting with 7” slips and bowls, elevators and slips for 7”
24	Overshot with packoff
25	Crossovers as needed
26	May need to weld onto 7" stub for lubricator installation during jet cutter operations, will need 7" stub and coupling with side outlet

Item no.	Tool Description
27	BOP rams for 7"
28	Crossover for the TIW valve
	For 7" Recovery Below Freepoint
29	Same list as above
30	Washpipe for 7”, Bushings and Crossovers
31	Burning shoes for 7”
32	Spear dressed for 7”
33	Inside Rotary Cutter
34	Oversized Guide
35	Cut Lip Guide
36	Wall Hook
37	Mechanical Pipe Cutter (run on e-line)
38	Knuckle Joint
39	Skirted Mill
40	Lead Impression Block (LIB)

10.3 Drilling Fluids Services

A 9.0 ppg Potassium Chloride (KCl) PolyTek water-based mud that provides appropriate shale inhibition will be used during the casing recovery operations. PolyTek mud is commonly used in the Aliso Canyon field with excellent results. A clear filtered KCl brine system will be used when the downhole camera is run. A detailed fluids program for both systems will be provided. Some of the key fluids considerations are as follows.

- All mud testing equipment should be checked and re-calibrated to ensure accuracy, especially the rheometers. All chemicals used for testing should be fresh. A proper mud lab must be on location for use by the mud engineer.
- As monitoring the percent low gravity solids is very important, a 50cc retort must be on location for use.
- It is important that the rig solids control equipment and mixing system be evaluated and maintenance performed to ensure optimum performance. Only square mesh API shaker screens should be used. A centrifuge is required to remove low gravity solids and LCM from the drilling fluid. It must be arranged so that solids can be removed while circulating or not circulating.
- A 100 bbl pre-mix tank may be required on location for LCM and hole cleaning pills.
- A mud engineer should be on location at all times while mixing mud, diluting, adding chemicals, tripping, during occurrences of lost circulation, and while circulating. One or complete mud checks will be required daily. Even if the mud has not been circulated, contaminants such as water and bacteria may change the properties.
- The drilling fluid formulation (with max % low gravity solids simulated with Rev Dust) should be tested in the mud laboratory to ensure that the correct properties will be attained. The temperature and duration of the heat aging should be agreed. The

formulation should then be tested for lubricity, and other lubricants tested to improve lubricity if needed.

- The range of all critical properties should be noted on the mud report to compare with actual results. Reporting should also include the product usage, daily material balance formulation, mud volume reporting (especially lost circulation volumes), and sweep reports. The remarks column should highlight any changes or trends to included ECD and torque. Torque monitoring will be especially important if wash pipe operations are required.
- Mud and fluid samples will be collected and documented according to the document; Aliso Canyon RCA SS-25 Site Evidence Collection and Documentation Protocol, April 28, 2016, Version 008 (or latest version) by Blade.
    - Samples of the mud will be collected when the liquid mud is transferred to the rig mud tanks. The mud sample will be chemically fingerprinted to determine the composition of the mud.
    - Samples of the mud or other fluids will be collected when any liquid mud or other fluid is delivered to the SS-25 site. The fluid samples will be chemically fingerprinted to determine the composition of the mud or fluid.
- Mud product additives to the mud system and quantities of additives will be monitored and recorded for the purpose of determining the composition of the mud. Mud chemistry details will also be provided by the mud supplier.

10.4 Filtration Services

Filtration services will be required to filter the brine system to a suitable NTU value prior to running the downhole camera.

10.5 Cementing Services

The cementing services for the 2-7/8" tubing plug, the setting of P&A plugs and the 7" tieback primary cementing operations will be arranged.

10.6 Casing Crew Services

A casing crew will be used to lay down the tubing and casing strings. The company will also provide Torque monitoring equipment so that the breakout torque of each connection can be measured and recorded.

A saw (TRAV-L-CUTTER or equivalent) will be required to cut the 7" casing. In the event a made-up connection needs to be preserved and not be broken out.

10.7 Tubulars Handling Services

The following is a list of the tubulars handling equipment and services that will be required.

- Thread protectors
- Packaging for transport
- PU/LD machine
- Bolsters for 2-7/8" tubing

- Bumper rings for 2-7/8” tubing
- Bolsters for 7” casing

10.8 Other Required Equipment

The following is a partial list of various other equipment and tools that may be required.

- 2-7/8” CIBP
- 7” CIBP
- 7” and 11-3/4” casing scrapers
- 7” and 11-3/4” RBP’s
- 7” and 11-3/4” Test Packers
- 6,000 ft of 7” 23.0 ppf J55 LTC tie-back casing (or equivalent)
- 8,000 ft of 3-1/2” 13.30 ppf with 3-1/2 IF connections, S135 grade work string
- Centrifuge
- Ditch magnet

10.9 Rigs

Rigs, rig types and plans are discussed in Section 3.

11 Appendix 1: SS-25A Well Data

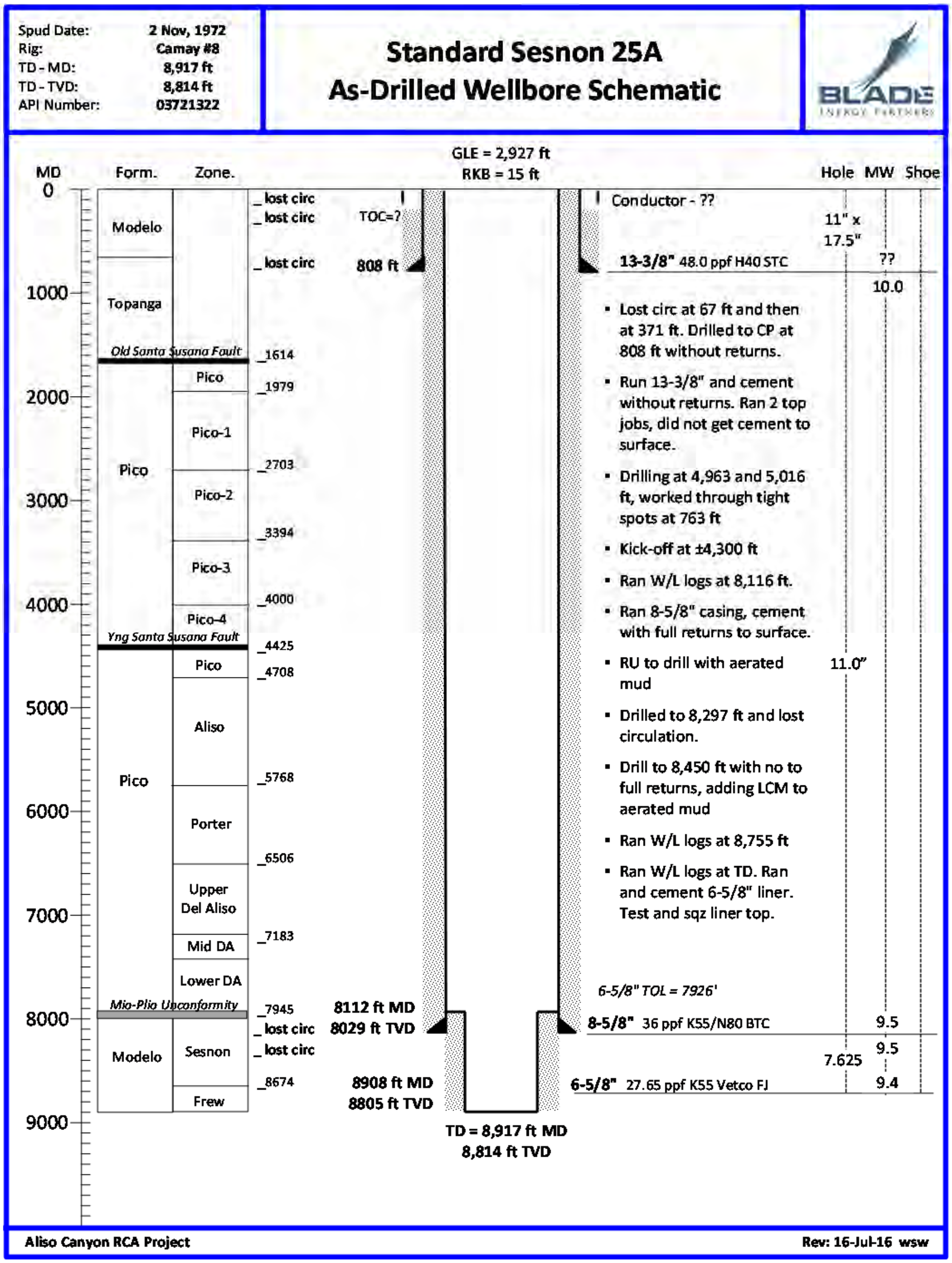


Figure 51. SS-25A As-Drilled Wellbore Schematic

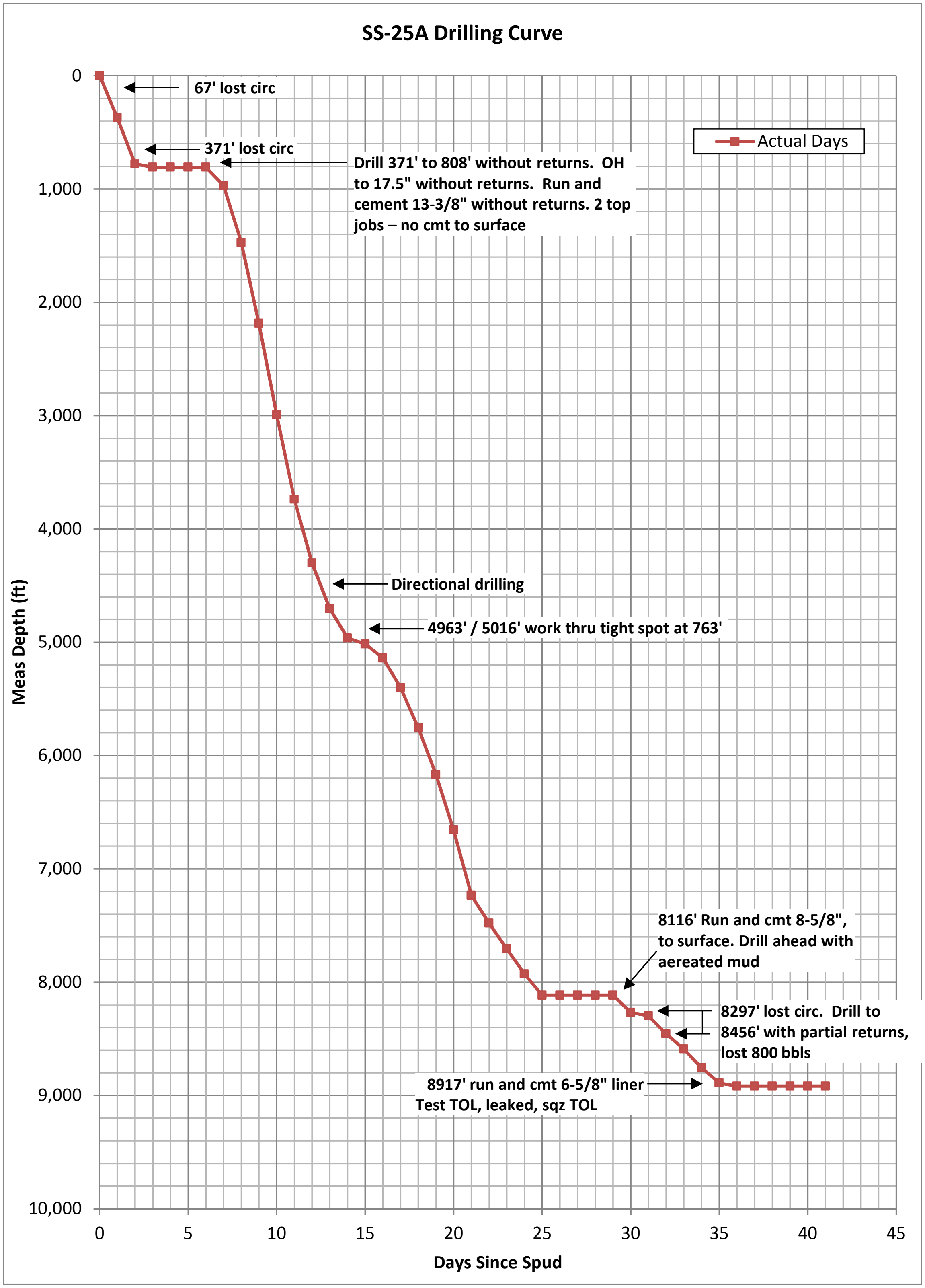


Figure 52. SS-25A Drilling Curve

Well: SS-25A

28-May-16

Drilling Operations Summary

Report Date	Day	Meas Depth	MW (lb/ft3)	ft per Day	Mwt (ppg)	Hole Size	Operations Summary
	0	0					
2-Nov-72	1	371	??	371		11.00	Spud. Drill to 371'. Lost Circ at 67 and 371'. Treat mud w/LCM
3-Nov-72	2	779	??	408		11.00	Att to re-gain circ. Drill to 779 with no returns
4-Nov-72	3	808	??	29		17.50	Drill to 808' with no returns. OH to 17.5" with no returns
5-Nov-72	4	808	??	0		17.50	Fin OH. Ran Ran 13-3/8" csg to 808 ft. Cemented casing with no returns. Ran Top job at 80 ft. No cmt to surface
6-Nov-72	5	808	??	0		17.50	Ran 2nd top job at 80 ft. No cmt to surface. Cut csg, NU WH and BOP
7-Nov-72	6	808	??	0		17.50	Rig repairs. TIH, drilling out
8-Nov-72	7	970	75.0	162	10.03	11.00	Drilling
9-Nov-72	8	1,472	67.0	502	8.96	11.00	Drilling
10-Nov-72	9	2,186	72.0	714	9.63	11.00	Drilling
11-Nov-72	10	2,992	70.0	806	9.36	11.00	Drilling
12-Nov-72	11	3,739	72.0	747	9.63	11.00	Drilling
13-Nov-72	12	4,301	71.0	562	9.49	11.00	Drilling
14-Nov-72	13	4,705	70.0	70	9.36	11.00	Drilling
15-Nov-72	14	4,963	71.0	258	9.49	11.00	Drilling. Work tools past tight spot in 13-3/8" at 763 ft
16-Nov-72	15	5,016	70.0	53	9.36	11.00	Drilling. Work tools past tight spot in 13-3/8" at 763' again
17-Nov-72	16	5,140	71.0	124	9.49	11.00	Drilling
18-Nov-72	17	5,400	71.0	260	9.49	11.00	Directional drilling
19-Nov-72	18	5,755	71.0	355	9.49	11.00	Directional drilling
20-Nov-72	19	6,170	73.0	415	9.76	11.00	Directional drilling
21-Nov-72	20	6,656	72.0	486	9.63	11.00	Directional drilling
22-Nov-72	21	7,234	73.0	578	9.76	11.00	Directional drilling
23-Nov-72	22	7,480	72.0	246	9.63	11.00	Directional drilling
24-Nov-72	23	7,706	72.0	226	9.63	11.00	Directional drilling
25-Nov-72	24	7,928	72.0	222	9.63	11.00	Directional drilling
26-Nov-72	25	8,116	71.0	188	9.49	11.00	Directional drilling
27-Nov-72	26	8,116	71.0	0	9.49	11.00	Ran E-logs. Ran 8-5/8" casing to 8112 ft. M&P first stage cmt - full returns. Open stage collar at 3000 ft. Pump second stage cmt - full returns, had cmt to surface
28-Nov-72	27	8,116	71.0	0	9.49	11.00	No report
29-Nov-72	28	8,116	71.0	0	9.49	11.00	NU BOPs. Drill out with 7-5/8" bit to 8085'. Shot WSO perfs at 8075'. Ran Jonson tester and tested perfs
30-Nov-72	29	8,116	71.0	0	9.49	11.00	Rig up to drill with aereated mud
1-Dec-72	30	8,267	70.0	151	9.36	7.625	Drill out shoe, drill ahead
2-Dec-72	31	8,297	69.0	30	9.22	7.625	Drill to 8297'. Lost Circ. PU to 8100' and LCM to mud
3-Dec-72	32	8,456	69.0	159	9.22	7.625	Drill to 8456' w/ no to full circ. Lost 800 bbls mud. Add LCM to aereated mud, regain full ciculation
4-Dec-72	33	8,590	69.0	134	9.22	7.625	Drilling
5-Dec-72	34	8,755	69.0	165	9.22	7.625	Drilling. C&C to log
6-Dec-72	35	8,890	70.0	135	9.36	7.625	Ran Schlum WL logs. Drilling
7-Dec-72	36	8,917	*70.0*	27	9.36	7.625	Drill to TD at 8917'. Lost 3 cones and one stab blade
8-Dec-72	37	8,917		0		7.625	Ran Schlum WL logs. Condition hole for liner
9-Dec-72	38	8,917		---		7.625	Ran 6-5/8" liner to 8908', with TOL at 7926'. Cement liner. *(no mention of returns, so assume full LC was not a prob)*
10-Dec-72	39	8,917		---		5.625	Clean out to TOL. Ran 5-5/8" bit and scraper

11-Dec-72	40	8,917		---		5.625	Work on frozen lines. Cont RIH, tag at 8903 ft
12-Dec-72	41	8,917		---		5.625	Test liner top - leaking. Squeeeze TOL. Drill out, test TOL - Ok
13-Dec-72	42	8,917		---		5.625	Shoot / test WSO perfs
14-Dec-72	43	8,917		---		5.625	Shoot / test WSO perfs
15-Dec-72	44	8,917		---		5.625	Shoot / test WSO perfs
16-Dec-72	45	8,917		---		5.625	Production testing
17-Dec-72	46	8,917		---		5.625	Production testing
18-Dec-72	47	8,917		---		5.625	Production testing
19-Dec-72	48	8,917		---		5.625	Production testing
20-Dec-72	49	8,917		---		5.625	Production testing
21-Dec-72	50	8,917		---		5.625	Ran 2-7/8" tubing to 8157.85 ft. RDMO **FINAL REPORT**

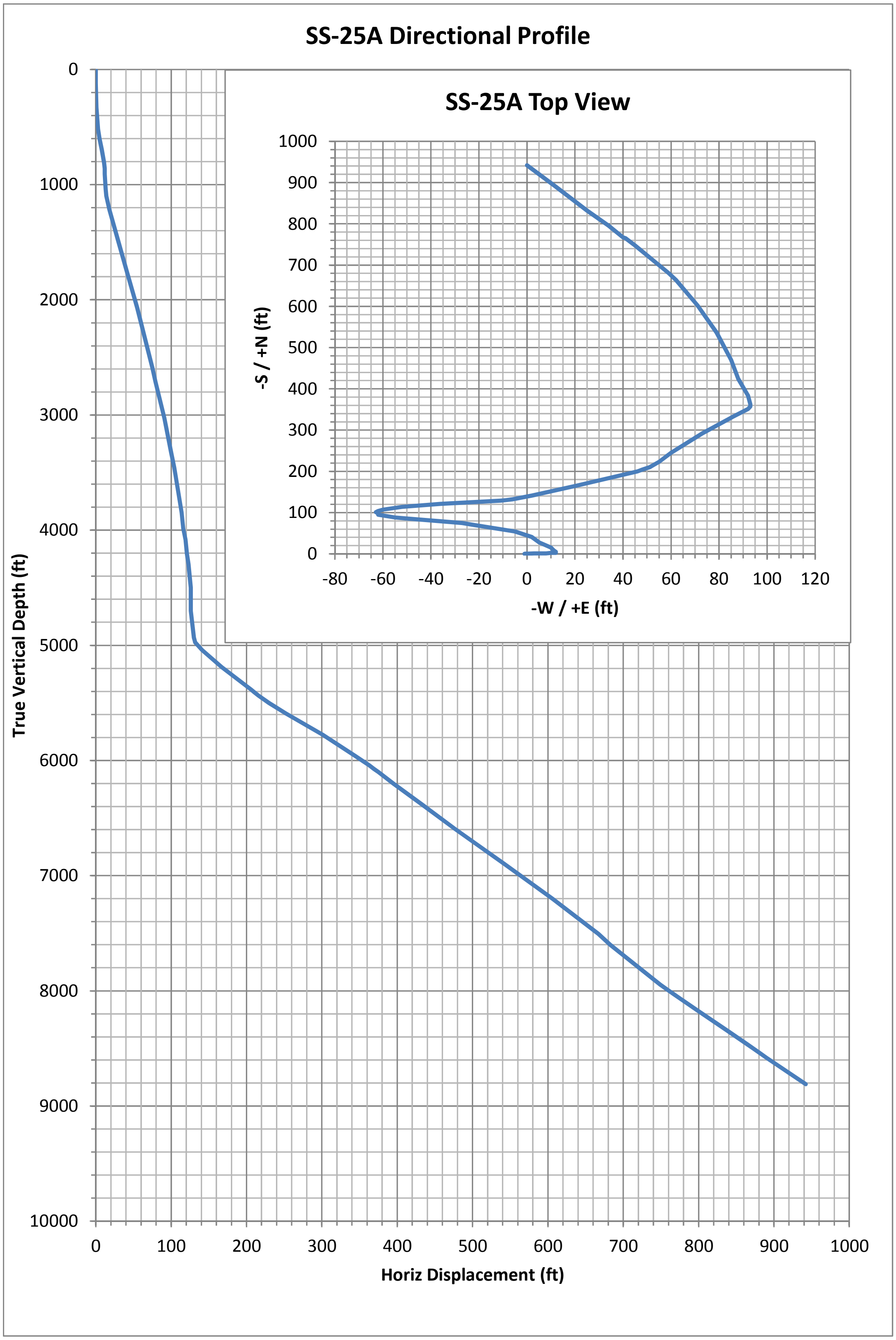


Figure 53. SS-25A Directional Profile

12 Appendix 2: SS-25B Well Data

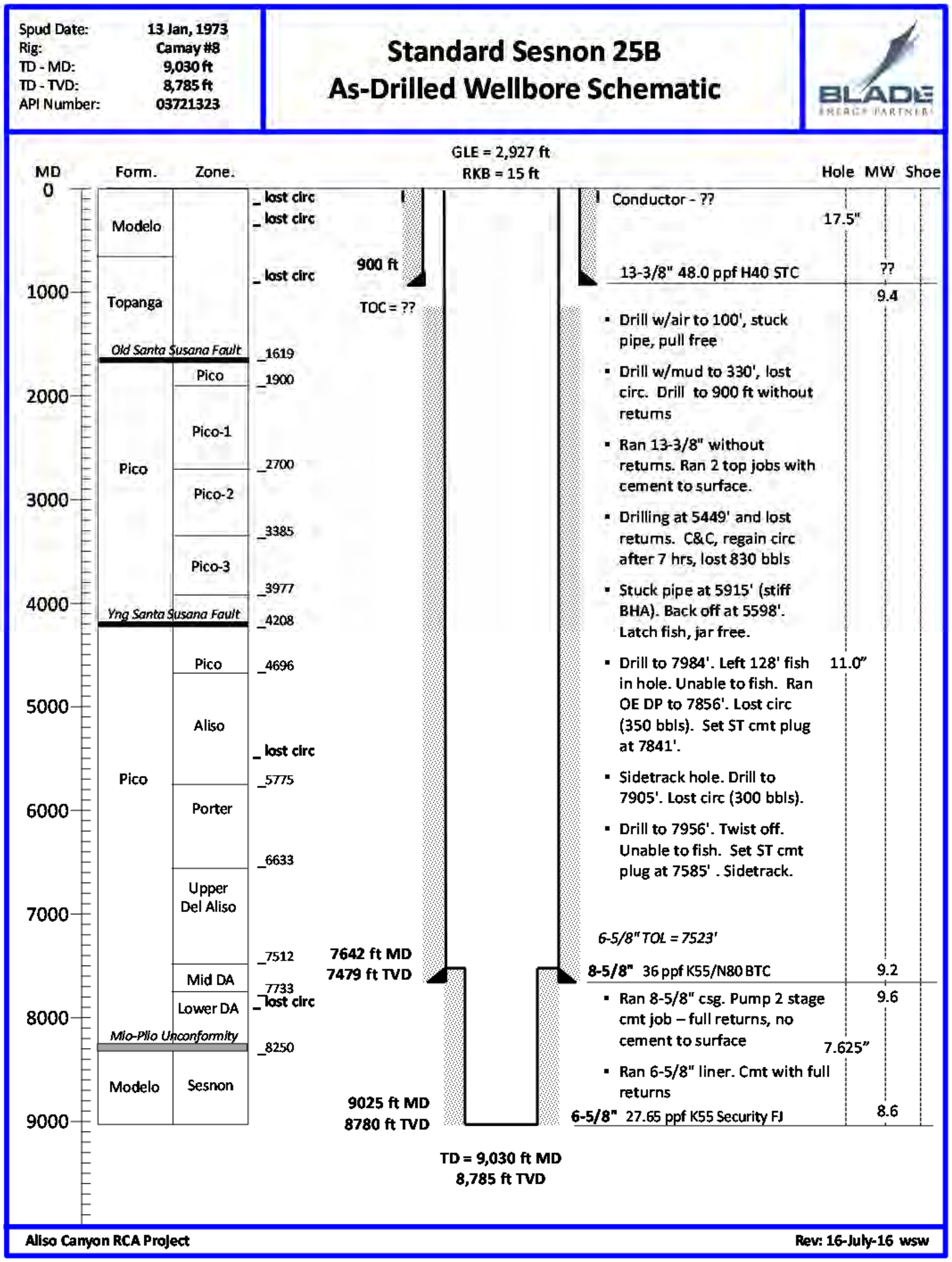


Figure 54. SS-25B As-Drilled Wellbore Schematic

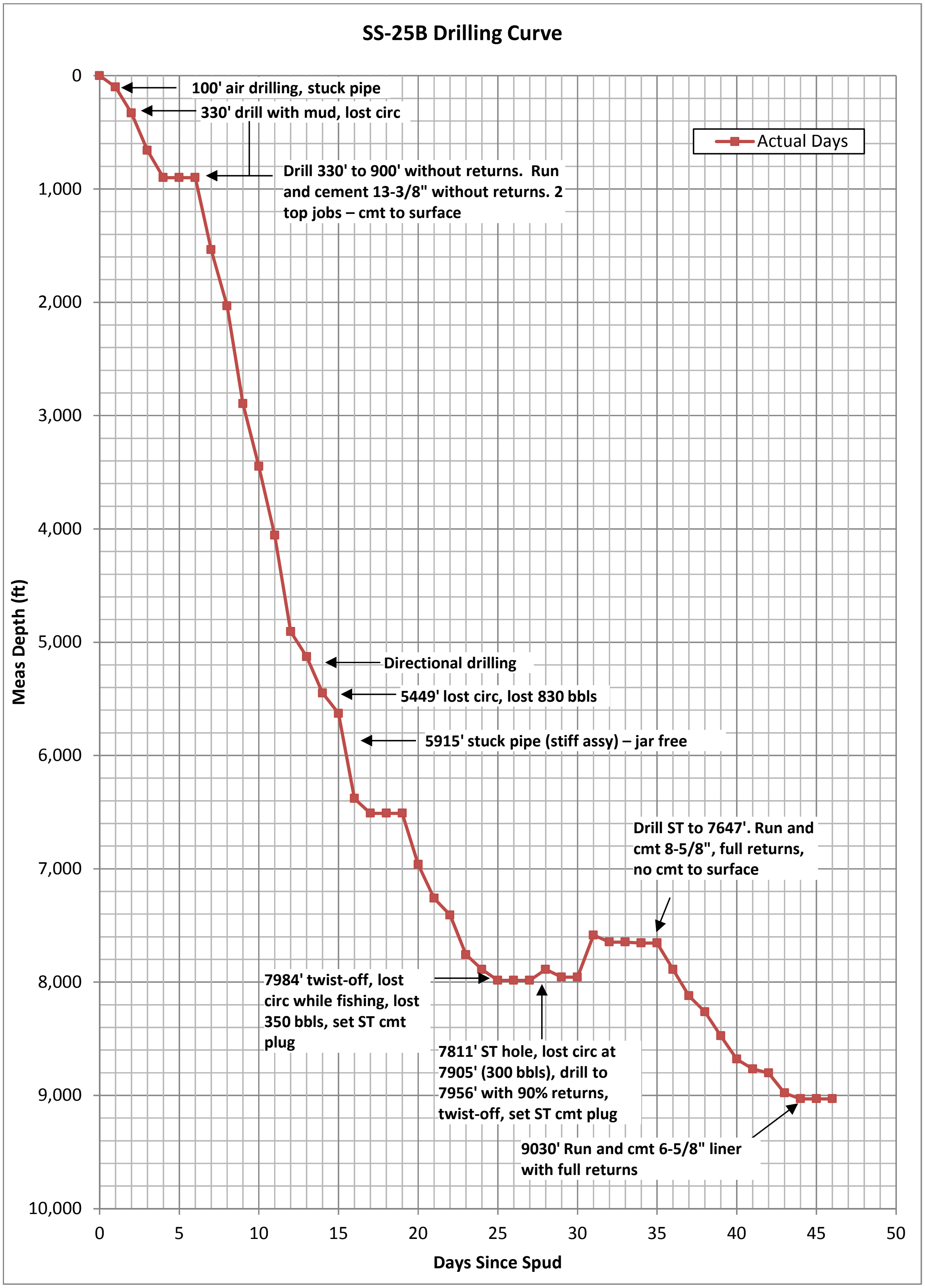


Figure 55. SS-25B Drilling Curve

Well: SS-25B

28-May-16

Drilling Operations Summary

Report Date	Day	Meas Depth	MW (lb/ft3)	ft per Day	Mwt (ppg)	Hole Size	Operations Summary
	0						
13-Jan-73	1	100		100		17.50	Spud. Drill to 100' with air - stuck pipe. Pull free w/150K.
14-Jan-73	2	330		230		17.50	LD air equip. Drill with mud to 330'. Lost returns. WO mud
15-Jan-73	3	660		330		17.50	Drill to 660' with no circulation
16-Jan-73	4	900		240		17.50	Drill to 900' with no circulation
17-Jan-73	5	900		0		17.50	Ran and cmt 13-3/8" to 900 ft. No returns during cmt job. Ran 2 top jobs and got cmt to surface. NU WH and BOP
18-Jan-73	6	900		0		17.50	Fin NU / test BOP
19-Jan-73	7	1,536	70.0	636	9.36	11.00	Drilled out. Drilling ahead
20-Jan-73	8	2,033	77.0	497	10.29	11.00	Drilling
21-Jan-73	9	2,894	72.0	861	9.63	11.00	Drilling
22-Jan-73	10	3,447	70.0	553	9.36	11.00	Drilling
23-Jan-73	11	4,057	70.0	610	9.36	11.00	Drilling
24-Jan-73	12	4,906	70.0	849	9.36	11.00	Drilling
25-Jan-73	13	5,128	68.0	70	9.09	11.00	Drilling
26-Jan-73	14	5,449	68.0	321	9.09	11.00	Drill to 5449', lost returns. C&C mud, regain circ after 7 hrs. Lost 830 bbls total
27-Jan-73	15	5,628	68.0	179	9.09	11.00	
28-Jan-73	16	6,380	69.5	752	9.29	11.00	Drill to 6651'. Directional drilling to 6380'
29-Jan-73	17	6,510	69.0	130	9.22	11.00	Directional drilling
30-Jan-73	18	6,510	71.0	0	9.49	11.00	Stuck pipe at 5915' (stiff drlg assy). Spot pill. Working pipe
31-Jan-73	19	6,510	68.0	0	9.09	11.00	Back off pipe at 5598'. Ran fishing assy. Jar on fish. Pull free
1-Feb-73	20	6,961	70.0	451	9.36	11.00	W&R hole. Directional drilling
2-Feb-73	21	7,260	70.0	299	9.36	11.00	Directional drilling
3-Feb-73	22	7,408	68.0	148	9.09	11.00	Directional drilling
4-Feb-73	23	7,758	68.0	350	9.09	11.00	Directional drilling
5-Feb-73	24	7,888	68.0	130	9.09	11.00	Directional drilling
6-Feb-73	25	7,984	68.0	96	9.09	11.00	Direct drill to 7984'. POH, left 128' fish in hole. TOF - 7856'
7-Feb-73	26	7,984	70.0	0	9.36	11.00	Ran fishing assy. Jar on fish - would not come free
8-Feb-73	27	7,984	68.0	0	9.09	11.00	RIH with OE DP to 7856'. Lost returns. 5 hrs to regain circ, lost 350 bbls. Set ST plug 7841' with full circulation. WOC
9-Feb-73	28	7,888	70.0	-96	9.36	11.00	Tag TOC at 7811'. Sidetrack hole from 7811 to 7888'
10-Feb-73	29	7,956	68.0	68	9.09	11.00	Direct drill to 7905' - lost circ (300 bbls). Drill to 7956' with 90% returns. Twist off, TOF at 7818'
11-Feb-73	30	7,956	68.0	0	9.09	11.00	Att to fish without success
12-Feb-73	31	7,585	69.0	-371	9.22	11.00	RIH with OE DP to 7650'. Set ST plug. WOC. Tag hard cmt at 7585'
13-Feb-73	32	7,647	69.0	62	9.22	11.00	Sidetrack from 7585' to 7647'. RU ran WL logs
14-Feb-73	33	7,647	68.0	0	9.09	11.00	C&C hole. Start running 8-5/8" casing
15-Feb-73	34	7,655	68.0	8	9.09	7.625	Ran 8-5/8" to 7642'. Cement 1st stage with full circulation. Shift stage collar at 2996'. Pump 2nd stage with full returns - no cement to surface. NU WH/BOP. Drill out to 7655'.
16-Feb-73	35	7,655	64.0	0	8.56	7.625	Change out myd system to low wt, low solids QTROL system
17-Feb-73	36	7,888	*64.0*	233	8.56	7.625	Directional drilling
18-Feb-73	37	8,121	64.0	233	8.56	7.625	Directional drilling
19-Feb-73	38	8,262	64.0	141	8.56	7.625	Directional drilling
20-Feb-73	39	8,475	64.0	213	8.56	7.625	Directional drilling
21-Feb-73	40	8,680	64.0	205	8.56	7.625	Directional drilling
22-Feb-73	41	8,767	64.0	87	8.56	7.625	Directional drilling

23-Feb-73	42	8,802	65.0	35	8.69	7.625	Drill to 8802'. Trip for washout
24-Feb-73	43	8,979	64.5	177	8.62	7.625	Directional drilling
25-Feb-73	44	9,030	64.0	51	8.56	7.625	Drill to TD at 9030'. Ran WL Logs
26-Feb-73	45	9,030	65.0	0	8.69	7.625	C&C hole. Ran 6-5/8" liner to 9025' with TOL at 7523'. Cement with full returns. Cleaning out to TOL
27-Feb-73	46	9,030	65.0	0		7.625	Clean out cmt to 9019'. Test TOL - ok.
28-Feb-73	47			-9,030			Test WSO perfs
1-Mar-73	48			0			Test WSO perfs
2-Mar-73	49			0			Test WSO perfs
3-Mar-73	50			0			Test WSO perfs
4-Mar-73	51						Production testing
5-Mar-73	52						Production testing
6-Mar-73	53						Production testing
7-Mar-73	54						Ran BP. Lost it in hole. Fishing
8-Mar-73	55						Production testing
9-Mar-73	56						Production testing
10-Mar-73	57						Production testing
11-Mar-73	58						Sand stabilization treatment with "Clay Lok"
12-Mar-73	59						LD drill string
13-Mar-73	60						Run tubing / completion
14-Mar-73	61						Run tubing / completion
15-Mar-73	62						Run tubing / completion
16-Mar-73	63						NU tree. RDMO. FINAL REPORT

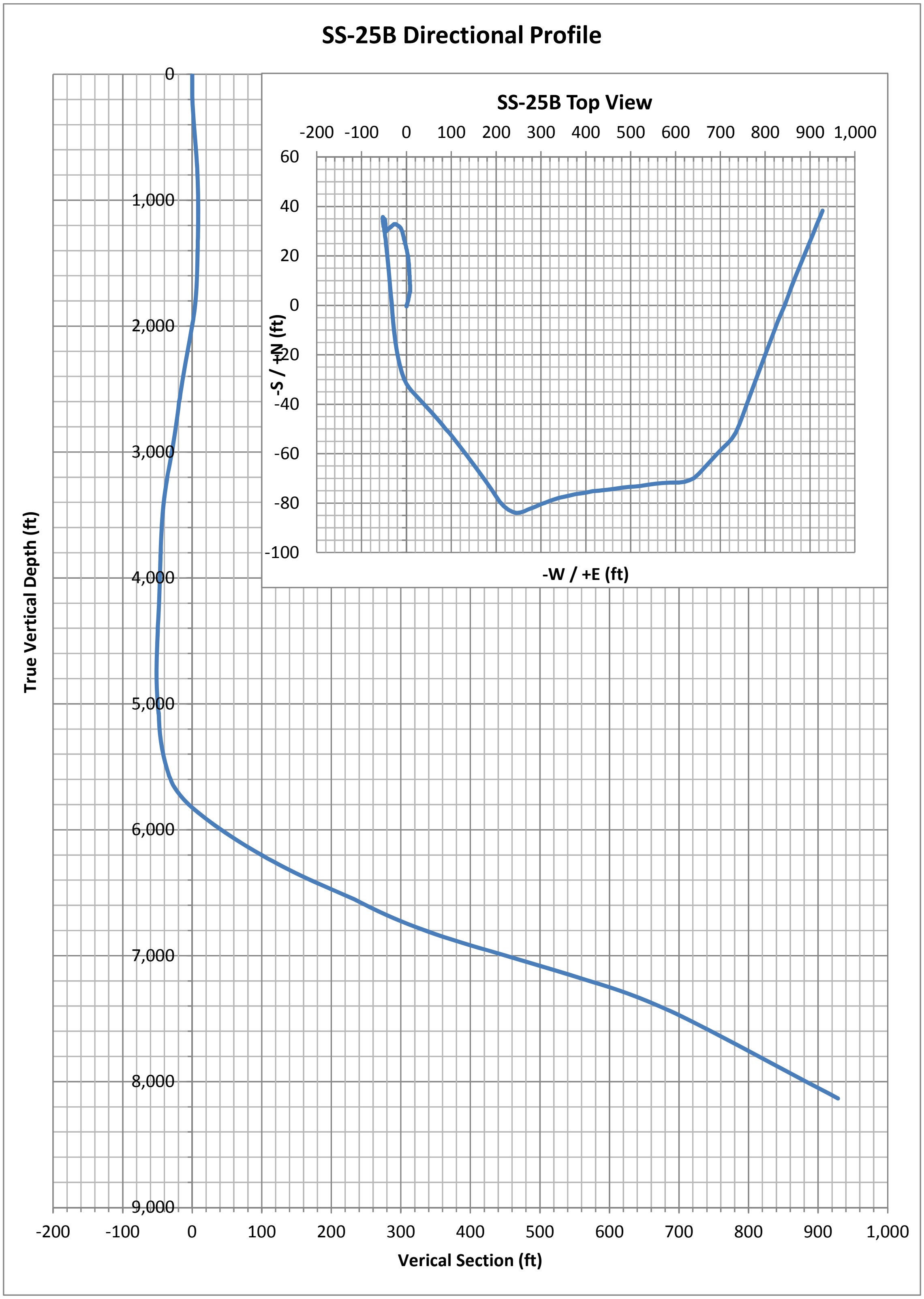


Figure 56. SS-25B Directional Profile

13 Appendix 3: P-39A Well Data

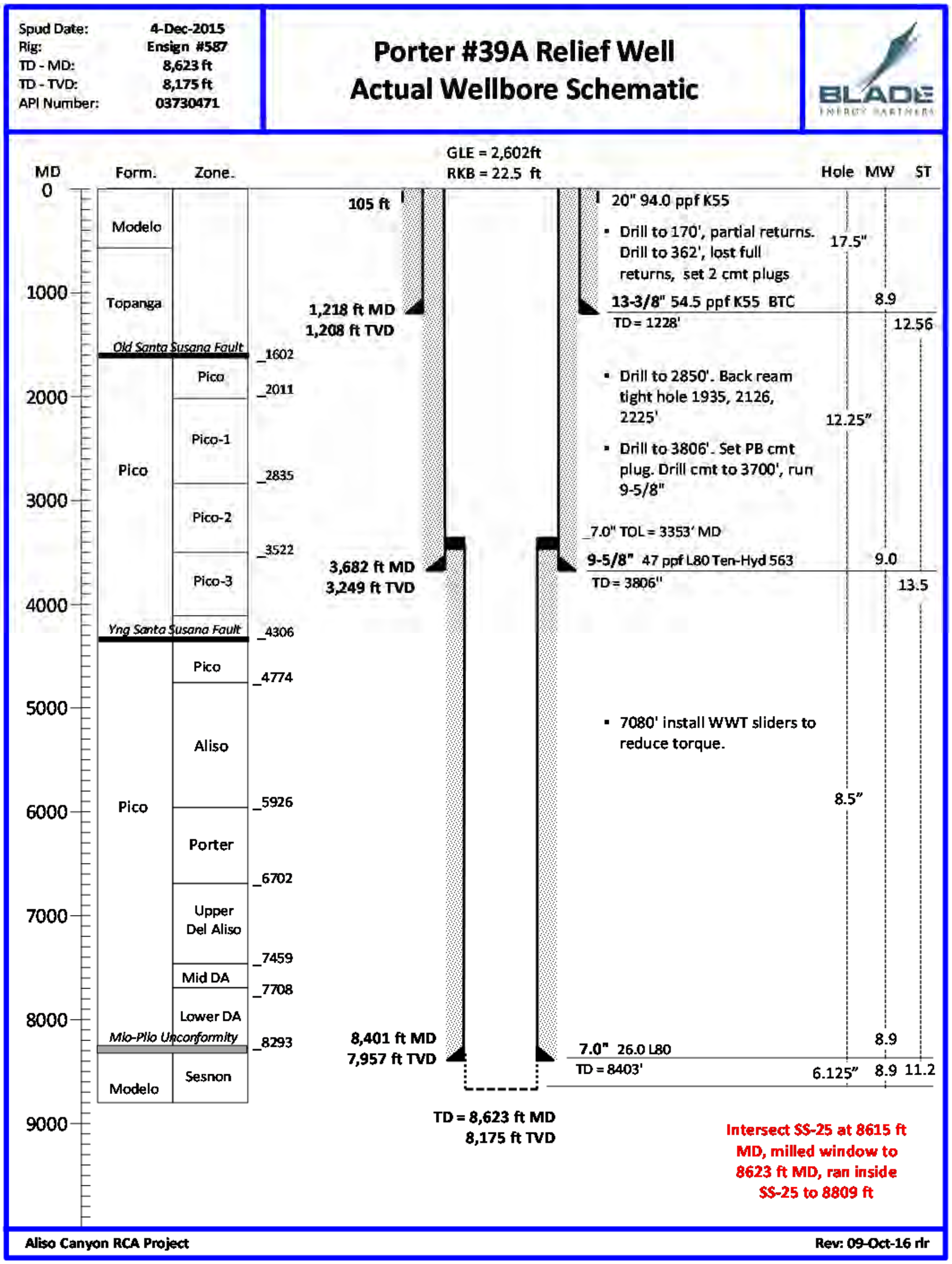


Figure 57. P-39A As-Drilled Wellbore Schematic

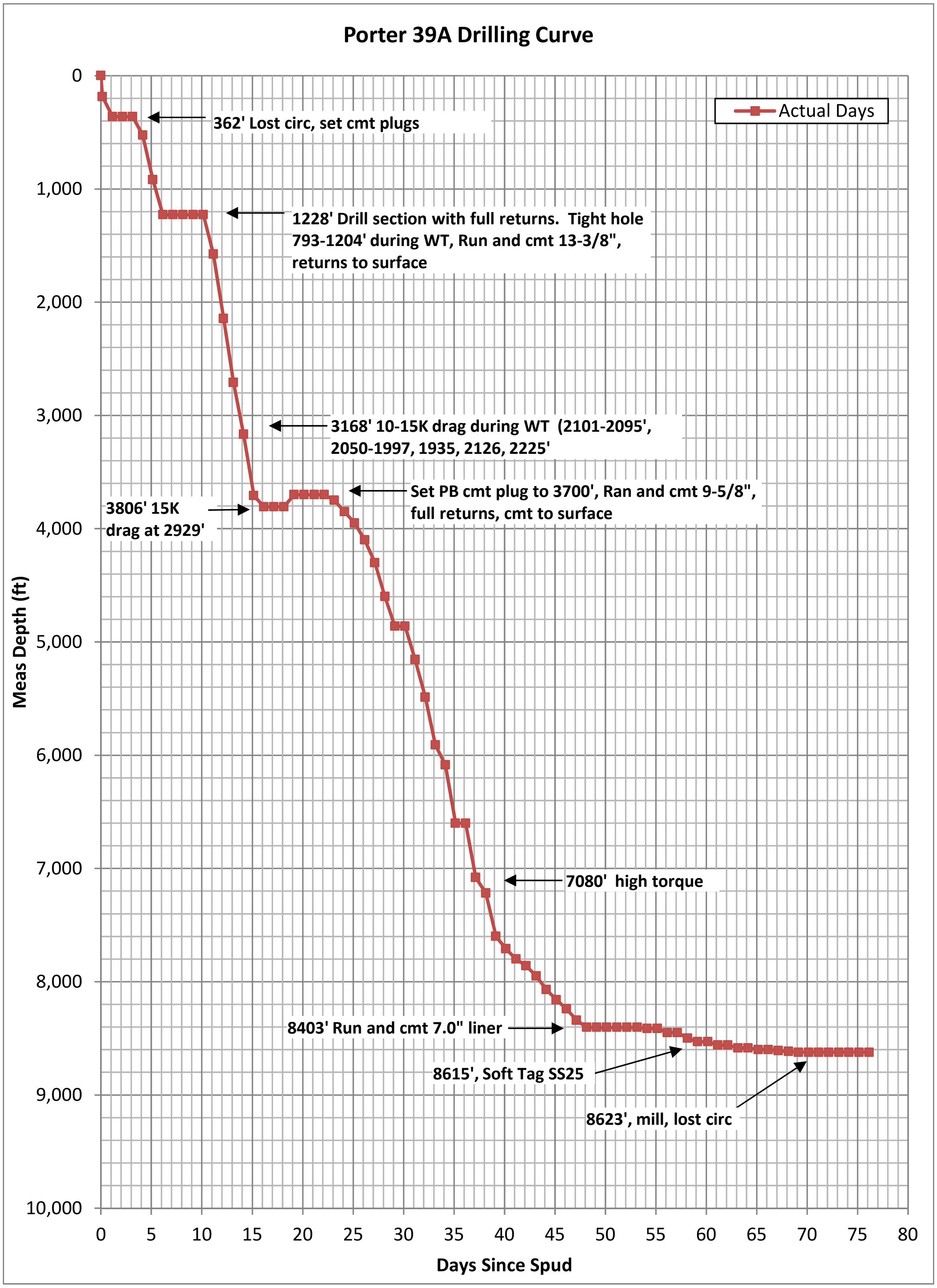


Figure 58. P-39A Drilling Curve

Well: Porter 39A

15-Jul-16

Drilling Operations Summary

Report Date	Rpt #	DFS	Meas Depth	MW (ppg)	ft per Day	Hrs Drlg	Avg ROP	Hole Size	Operations Summary
30-Nov-15	1								
1-Dec-15	2								
2-Dec-15	3								
3-Dec-15	4	0	0	-	-	-	-	-	Prep to Spud
4-Dec-15	5	0.15	185	8.6	185			17.5	Spud at 2030 hrs, drill to 170', started having losses, treat w/LCM
5-Dec-15	6	1.15	362	8.6	177	12.0	14.8	17.5	Cntrl drill w/LCM sweeps to control losses. Drill to 362'- lost full returns. Pump 40 bbl LCM, still had no returns. POH. Set 200' cmt plug on bottom
6-Dec-15	7	2.15	362	8.5	0	0.0	0.0	17.5	WOC plug #1. Hole not staying full. TIH, clean out cmt w/out rtrns. Set Cmt plug #2, WOC
7-Dec-15	8	3.15	362	8.5	0	0.0	0.0	17.5	WOC. RIH, tag cmt at 105'. Circ w/no retrns, Add LCM, drill cmt to 235', had 80% retrns. Static LR at 100-125 bph. POH. TIH to 228', set cmt plug #3. WOC
8-Dec-15	9	4.15	526	8.5	164	8.5	19.3	17.5	TIH w/ direct tools. Tag cmt at 95'. Drill cmt w/full returns, after 40 bbl loss at 113'. Drill to 526'
9-Dec-15	10	5.15	919	8.7	393	24.0	16.4	17.5	Direct drilling to 919 ft
10-Dec-15	11	6.15	1,228	8.8	309	19.0	16.3	17.5	Direct drilling to 1228 ft. Full returns. POH. Hole slick
11-Dec-15	12	7.15	1,228	8.7	0	-	-	17.5	Fin POH. RU WL - ran GR/Cal/Resist/Sonic from 1227-0 ft. TIH for WT. Some tight hole f/793-1204'. POH. RU and **run 13-3/8" to 1218'**. M&P cmt w/ full returns to surface, bumped plug
12-Dec-15	13	8.15	1,228	8.7	0	-	-	17.5	WOC. Cut 13-3/8". Pump 31 bbl 14.8# top job. Instal WH
13-Dec-15	14	9.15	1,228	8.7	0	-	-	17.5	Cont install / test WH. NU / test BOP
14-Dec-15	15	10.15	1,228	8.7	0	-	-	17.5	Fin testing BOP's. PU bit and BHA
15-Dec-15	16	11.15	1,575	8.9	347	11.5	30.2	12.25	TIH, clean out to shoe. POH. Ran CBL/USIT. TIH, drill out to 1238'. **Ran LOT to 12.56 ppge**. Drilling ahead
16-Dec-15	17	12.15	2,145	9.0	570	21.5	26.5	12.25	Direct drlg to 1996'. Ran WT to shoe. RIH direct drlg to 2145'
17-Dec-15	18	13.15	2,710	9.0	565	24.0	23.5	12.25	Directional drilling to 2710'.
18-Dec-15	19	14.15	3,168	9.1	458	20.0	22.9	12.25	Direct drlg to 2850'. C&C, POH to shoe. 10-15k tite spots. Backream f/2101-2095', and 2050-1997'. POH. TIH- ream tight hole at 1935, 2126' and 2225'. Safety ream to btm. Drill head to 3168'
19-Dec-15	20	15.15	3,708	9.0	540	24.0	22.5	12.25	Direct drill to 3708 ft
20-Dec-15	21	16.15	3,806	9.0	98	4.5	21.8	12.25	Drill to 3806'. C&C, POH. 15k drag at 2929'. RU Halco WL - ran WellSpot.
21-Dec-15	22	17.15	3,806	9.0	0	-	-	12.25	Ru SLB WL. Ran CBL/USIT in 13-3/8". RIH w/ WellSpot for Ranging run. POH. MU Halco DGR/EWR LWD. TIH, log hole f/1218 to 3038 ft
22-Dec-15	23	18.15	3,806	9.0	0	-	-	12.25	Ran Halco DGR/EWR LWD to 3806'. C&C, POH. LD LWD. RIH w/OE 5" DP to 3806'. M&P 30 bbl cmt plug. POH. WOC. TIH, tag cmt at 3628'. Drill soft cmt to 3690'
23-Dec-15	24	19.15	3,700	9.0	-106	-	-	12.25	C&C. POH to shoe. 5-15K OP from 3690-2570'. WOC. RIH to 3690'. Drilled hard cmt to 3700'. C&C, POH slick. RU and **run 9-5/8" to 3682'**. M&P cmt
24-Dec-15	25	20.15	3,700	9.0	0	-	-	12.25	fin cmt job with full retrns to surface. Lift BOP. Set Slips. Cut csg. NU WH. NU BOP
25-Dec-15	26	21.15	3,700	9.0	0	-	-	12.25	Cont NU BOP's.
26-Dec-15	27	22.15	3,700	8.9	0	-	-	12.25	Repair leaks. Fin BOP tests. TIH, drill out 3700' (KO plug). POH. MU direct assy, TIH
27-Dec-15	28	23.15	3,750	9.0	50	-	-	8.5	Fin TIH. Drill to 3750'. POH to shoe. **Ran FIT to 13.5 ppge**. POH. Ran gyro svy. POH

28-Dec-15	29	24.15	3,850	9.0	100	-	-	8.5	TIH w/direct assy. Drill to 3850'. C&C, POH. Ran WellSpot. TIH with direct BHA
29-Dec-15	30	25.15	3,950	9.0	100	-	-	8.5	Fin TIH. Direct drill to 3950'. C&C, POH slick. Ran WellSpot. RU SLB WL. Ran USIT/CBL/Neutron logs from 3682 to surf. MU direct BHA
30-Dec-15	31	26.15	4,100	8.9	150	-	-	8.5	TIH. Drill to 4100'. C&C, POH. Ran WellSpot. MU direct BHA
31-Dec-15	32	27.15	4,300	8.9	200	11.5	17.4	8.5	TIH. Drill to 4300'. C&C, POH. Made Ranging tool run with side entry sub. POH
1-Jan-16	33	28.15	4,600	8.9	300	23.0	13.0	8.5	TIH. Drill to 4600'. POH. Made Ranging tool run. POH
2-Jan-16	34	29.15	4,862	8.9	262	13.0	20.2	8.5	TIH. Direct drill to 4862'. Generator problems. POH to shoe, slick. Rig repairs. POH
3-Jan-16	35	30.15	4,862	8.9	0	-	-	8.5	Rig repairs
4-Jan-16	36	31.15	5,156	8.9	294	14.0	21.0	8.5	Fin repairs. TIH w/direct BHA. Drill to 5156'.
5-Jan-16	37	32.15	5,488	8.9	332	15.0	22.1	8.5	Drilled to 5488'. Halco WL truck issues. C&C, POH. Made Ranging tool run
6-Jan-16	38	33.15	5,910	8.9	422	20.5	20.6	8.5	Fin Ranging run. TIH. Direct drill to 5910'
7-Jan-16	39	34.15	6,085	8.9	175	7.5	23.3	8.5	Drill to 6000'. C&C, POH - had 15-20K OP at 5693', 5572, 5530'. Made Ranging tool run. TIH, Direct drill to 6085'.
8-Jan-16	40	35.15	6,600	8.9	515	23.0	22.4	8.5	Directional drilling to 6600 ft
9-Jan-16	41	36.15	6,600	8.9	0	-	-	8.5	Ran WT. C&C. POH. RU WL. Ran Wellspot. PU BHA. TIH. Install WWT non-totating protectors
10-Jan-16	42	37.15	7,080	8.9	480	23.5	20.4	8.5	Fin TIH. Install WWT sliders to reduce torque. Direct drilling
11-Jan-16	43	38.15	7,217	8.9	137	6.0	22.8	8.5	Direct drill to 7197'. Ran WT to 6600'. Had 15K OP. C&C, POH. Ran ranging log. POH. Rig service. TIH. Direct drilling
12-Jan-16	44	39.15	7,600	8.9	383	16.0	23.9	8.5	Direct drilling to 7600'. Ran WT. C&C. POH
13-Jan-16	45	40.15	7,710	8.9	110	5.0	22.0	8.5	Ran ranging logs. TIH. Direct drilling to 7710'. C&C. POH
14-Jan-16	46	41.15	7,800	8.9	90	4.5	20.0	8.5	Fin POH. Ran ranging log. TIH, Drill to 7800'. C&C. POH
15-Jan-16	47	42.15	7,860	8.9	60	3.0	20.0	8.5	Fin POH. Ran ranging log. TIH, Drill to 7860'. C&C. POH
16-Jan-16	48	43.15	7,950	8.9	90	4.5	20.0	8.5	Fin POH. Ran ranging log. TIH. Drill to 7950'. POH. Pipe pulling wet-lost 140 bbls. Running ranging log
17-Jan-16	49	44.15	8,070	8.9	120	5.5	21.8	8.5	Fin ranging log. PU BHA. TIH. Direct drill to 8070'. POH. Ran ranging log. PU BHA. TIH
18-Jan-16	50	45.15	8,160	8.8	90	-	-	8.5	Fin TIH. Direct drill to 8160'. POH. Ran ranging log. PU BHA. TIH.
19-Jan-16	51	46.15	8,240	8.7	80	-	-	8.5	Fin TIH. Direct drill to 8240'. POH. Ran ranging log. PU BHA. TIH
20-Jan-16	52	47.15	8,340	8.7	100	-	-	8.5	Fin TIH. Direct drill to 8340'. POH
21-Jan-16	53	48.15	8,403	8.8	63	5.5	11.5	8.5	Ran ranging log. PU BHA. TIH Direct drill to 8403'
22-Jan-16	54	49.15	8,403	8.8	0	-	-	8.5	POH. Ran ranging log. RIH w. 9-5/8" scraper to 3395'. POH. TIH w/ clean out assy
23-Jan-16	55	50.15	8,403	8.9	0	-	-	8.5	Fin TIH. Ran 2 WT's. C&C to run casing. POOH. Running 7.0" liner
24-Jan-16	56	51.15	8,403	8.9	0	-	-	8.5	**Fin running 7.0" liner w/shoe at 8401', and TOL at 3353'. M&P cmt. LD 5" DP**
25-Jan-16	57	52.15	8,403	8.9	0	-	-	8.5	Fin LD 5.0" DP. PU 3.5" DP. Test BOPs.
26-Jan-16	58	53.15	8,403	8.7	0	-	-	8.5	Fin BOP test. TIH picking up 3-1/2" DP and HWT. Att circ - string plugged. POH. TIH OE, C&C
27-Jan-16	59	54.15	8,413	8.9	10	0.5	20.0	6.125	TIH. Test TOL to 3000 psi. Drill out liner an 10' new hole to 8413'. **Attempt 13.5 ppge FIT - broke down at 11.2 ppge**. POH
28-Jan-16	60	55.15	8,413	8.9	0	-	-	6.125	PU BHA. TIH. Survey. POH
29-Jan-16	61	56.15	8,450	8.9	37	3.5	10.6	6.125	Ran WL logs. PU BHA. TIH. Direct drilling to 8450'. POH
30-Jan-16	62	57.15	8,450	8.9	0	-	-	6.125	Ran survey Ran ranging log. TIH with drilling assy
31-Jan-16	63	58.15	8,500	8.9	50	-	-	6.125	Direct drill to 8500'. POH. Ran gyro. Ran ranging log.
1-Feb-16	64	59.15	8,530	9.0	30	-	-	6.125	TIH, direct drill thru cap rock at 8518', cont drill to 8530'. POH
2-Feb-16	65	60.15	8,530	8.9	0	-	-	6.125	Ran ranging logs. Ran WL logs. PU drlg assy and TIH, C&C, WO daylight
3-Feb-16	66	61.15	8,560	8.9	30	-	-	6.125	Direct drill to 8560'. POH. TIH, ran survey
4-Feb-16	67	62.15	8,560	8.9	0	-	-	6.125	POH. Ran ranging logs. PU BHA, TIH
5-Feb-16	68	63.15	8,585	8.9	25	-	-	6.125	TIH. C&C. WOO. Direct drill to 8585'. POH

6-Feb-16	69	64.15	8,585	8.9	0	-	-	6.125	Ran gyro. Ran ranging log. TIH with BHA
7-Feb-16	70	65.15	8,600	8.9	15	-	-	6.125	TIH. WOO. Direct drill to 8600'. POH. TIH with gyro
8-Feb-16	71	66.15	8,600	8.9	0	-	-	6.125	Ran ranging log. TIH with BHA
9-Feb-16	72	67.15	8,610	8.9	10	-	-	6.125	Direct drill to 8610'. POH. Ran ranging log. PU BHA, TIH
10-Feb-16	73	68.15	8,615	8.9	5	-	-	6.125	TIH. Direct drill to 8615'. **Soft tag SS-25** well. POH. Ran ranging log. PU concave mill/BHA. TIH
11-Feb-16	74	69.15	8,623	8.9	8	5.0	1.6	6.125	WO daylight. Tag SS25 at 8615.3'. Mill 2.5". Lost full returns. POH to 8405'. Fill hole- lost 280 bbls. Regain circ. SI well. Pump & fill SS25 with mud. Pumped total of 505 bbls. Monitor both wells - static. Bled off pressure, SS25 utubed 21 bbls, then stabilized. Mill to 8623'. POH.
12-Feb-16	75	70.15	8,623	8.9	0	-	-	6.125	Fin POH. PU 10 jts 2-7/8" tubing. TIH, tag SS25 liner at 8681'. C&C, hole taking 6bph. Run inside SS25 to 8809'. M&P 20 bbl cmt plug. POH
13-Feb-16	76	71.15	8,623	8.9	0	-	-	6.125	POH. TIH with 6-1/8" bit to 7030'. W&R to 8605'. Wash to 8618'. Close AP. Apply 150 psi, estab communication with SS25. CBU at 8616'. POH. PU 10 jts tubing. TIH, tag cmt at 8533' (8658"?). POH
14-Feb-16	77	72.15	8,623	8.9	0	-	-	6.125	Fin POH. PU 7" cmt retainer. TIH, set retainer at 8298'. Pump 42 bbls 14.8# cmt (into SS-25). PU, WOC
15-Feb-16	78	73.15	8,623	8.9	0	-	-	6.125	Fin WOC. Pump 7 bbls (150') 14.8# cmt on top of retainer. PU, CBU. POH. PU 6-1/8": bit and scraper. TIH
16-Feb-16	79	74.15	8,623	8.9	0			6.125	TIH w/scraper, tag cmt at 8060'. Polish to 8100' (PBTD). Test plug to 1000 psi for 30 min. C&C
17-Feb-16	80	75.15	8,623	8.9	0			6.125	Move mud to storage. Build 1000 bbls of 3% KCl mud. Change hole over to KCl. LD DP. PU 2-7/8" 6.5# L80 tubing string w/ packer, XN nipple, WFD sliding sleeve, SV. TIH
18-Feb-16	81	76.15	8,623	8.9	0			6.125	RIH w/tbg and packer to 7993'. Att to set packer. POH. PU new packer, TIH. Set packer w/EOT at 7993'.

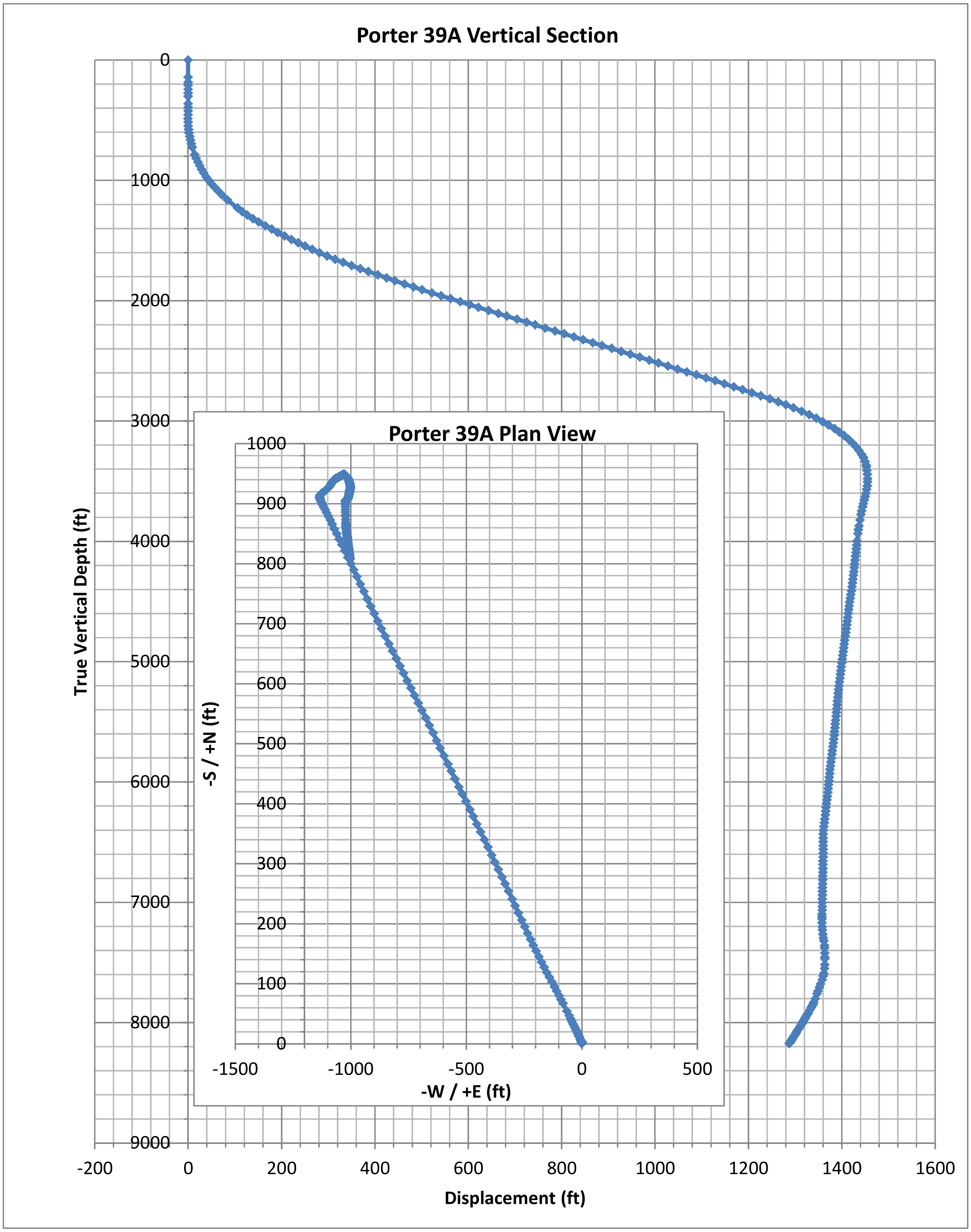


Figure 59. P-39A Directional Profile

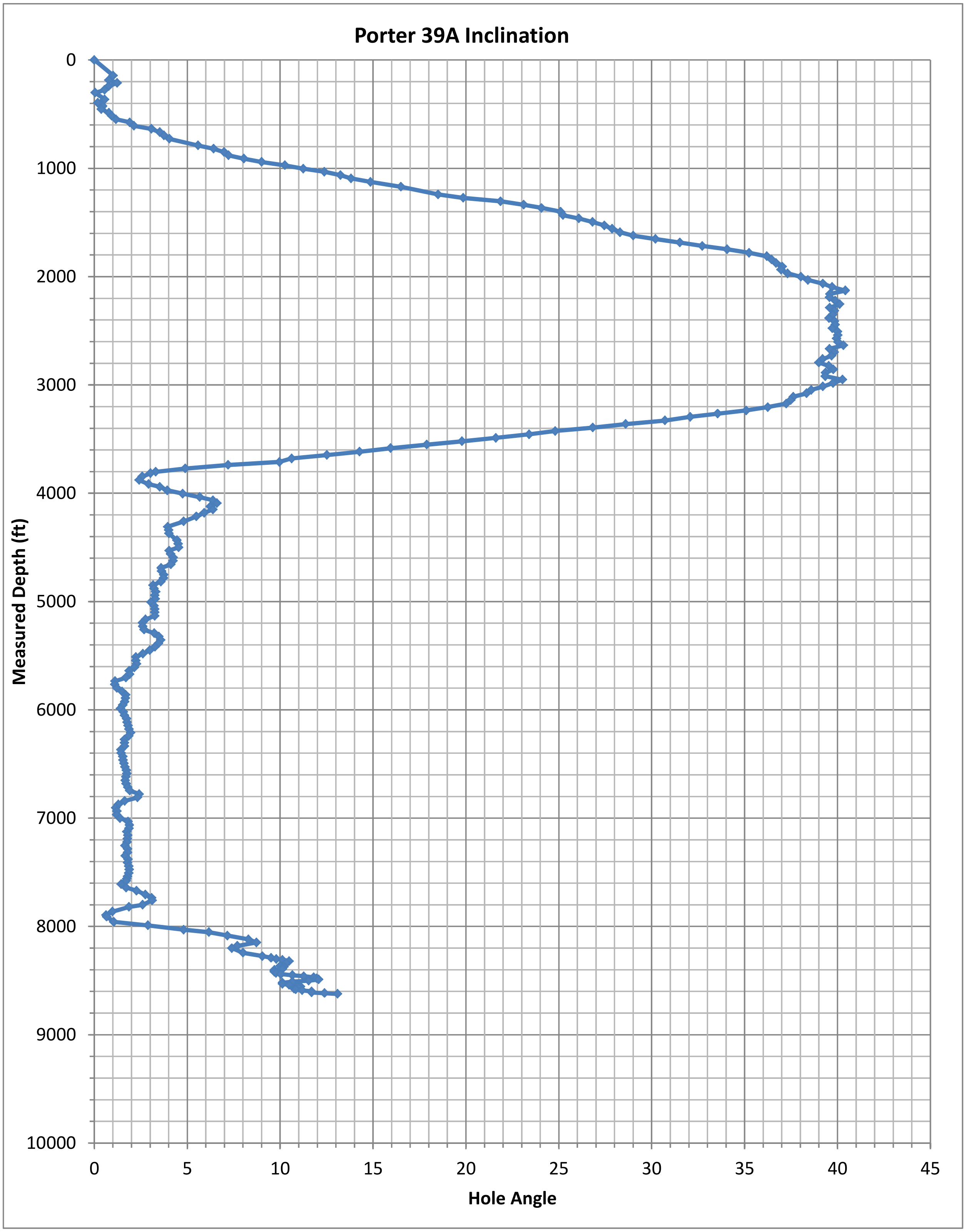


Figure 60. P-39A Inclination Plot

14 Appendix 4: SS-25 Drilling Reports

Well: SS-25

6-Jun-16

Drilling Operations Summary

Report Date	Day	Meas Depth	MW (lb/ft3)	ft per Day	Mwt (ppg)	Hole Size	Operations Summary
30-Sep-53	0						Fin MIRU
1-Oct-53	1	169		169		10.625	Spudded. Drill 10-5/8" hole. Lost circulation at 169' for 5 hours.
2-Oct-53	2					10.625	
3-Oct-53	3	741				10.625	
4-Oct-53	4					10.625	
5-Oct-53	5					10.625	
6-Oct-53	6					10.625	
7-Oct-53	7					10.625	
8-Oct-53	8					10.625	
9-Oct-53	9					10.625	
10-Oct-53	10					10.625	
11-Oct-53	11					10.625	
12-Oct-53	12					10.625	
13-Oct-53	13					10.625	
14-Oct-53	14	2,567		0		16.00	Drilled 10-5/8" hole to 2567'. Ran SLB elogs. OH to 16" to 212'
15-Oct-53	15	2,567		0		16.00	OH
16-Oct-53	16	2,567		0		16.00	OH
17-Oct-53	17	2,567		0		16.00	Opened hole to 16" to 990'.
18-Oct-53	18	2,567		0		16.00	**Ran and cemented 11-3/4"** 42 ppf Youngstown STC H-40 casing at 990'. Cmtd with 600 sx 1:1 Diamix followed by 100sx neat cement. Lost circ with 114cuft of cement slurry to displace. Top cement job #1 75sx neat cement.
19-Oct-53	19					16.00	Top cement job #2 60sx neat cement. Cleaned out and found cement at 984'.
20-Oct-53	20					10.625	
21-Oct-53	21					10.625	Drilling
22-Oct-53	22	2,925				10.625	Drilled 10-5/8" hole to 2925'. Twisted off DC. Fishing at 2925'.
23-Oct-53	23	2,925				10.625	Fishing
24-Oct-53	24	2,925				10.625	Recovered DC.
25-Oct-53	25					10.625	
26-Oct-53	26	3,073				10.625	Drilled 10-5/8" hole to 3073'. Twisted off 28 joints DP and 2 DC. Recovered fish.
27-Oct-53	27					10.625	
28-Oct-53	28					10.625	
29-Oct-53	29					10.625	
30-Oct-53	30					10.625	
31-Oct-53	31					10.625	
1-Nov-53	32					10.625	
2-Nov-53	33					10.625	
3-Nov-53	34					10.625	
4-Nov-53	35	4,362				10.625	Drilled 10-5/8" hole to 4362'. Changed to Carbonox mud at 4350'.
5-Nov-53	36	4,530		168		10.625	Drilling
6-Nov-53	37	4,630		100		8.5	Drilled 8-1/2" hole from 4530' to 4630'. Ran SLB elog at 4630'. OH to 10-5/8" to 4552'
7-Nov-53	38	4,685		55		8.5	OH to 10-5/8" to 4630'. Drill 8.5" hole

7-Nov-53	38	4,685		55		8.5	OH to 10-5/8" to 4630'. Drill 8.5" hole
8-Nov-53	39	4,765		80		8.5	
9-Nov-53	40	4,781		16		8.5	Drilled 8-1/2" hole to 4781'. Ran SLB elog at 4781'. Ran Johnson formation tester. Tested 1,591,000cf/d. Charts shows 1100psi BHP.
10-Nov-53	41	4,796		15		8.5	OH to 10-5/8". Drill 8.5" hole
11-Nov-53	42					8.5	
12-Nov-53	43					8.5	
13-Nov-53	44	4,910				8.5	Drill. Ran SLB log
14-Nov-53	45	4,910		0		8.5	Ran Johnson formation tester. BHP 1250psi. Re-Ran SLB logs. OH to 10-5/8" to 4788'
15-Nov-53	46					8.5	
16-Nov-53	47	4,948				8.5	Drilled 8-1/2" hole to 4948'. Ran Lane Wells Neutron, GR and sidewall sampler.
17-Nov-53	48	4,948		0		8.5	Set 60sx Colton Slow cement plug at 4948'. WOC. Found no cement.
18-Nov-53	49	4,948	74.0	0	9.89	8.5	Set 60sx Colton Slow cement plug at 4948'. WOC. Found TOC 4830'. CO to 4860'. MW 74#.
19-Nov-53	50	4,948		0		8.5	Ran Johnson formation tester. Flow test well. Test tools stuck. Jarred on fish, no success. [Fish 893' length; 4.5" DP and Johnson Tester from 3967' - 4860']
20-Nov-53	51	4,948				8.5	Jar w/out success. POOH. Released McAteer Drilling Rig. RDMO.
21-Nov-53	52	4,948				8.5	Idle
22-Nov-53	53	4,948				8.5	Idle
23-Nov-53	54	4,948				8.5	Idle
24-Nov-53	55	4,948				8.5	Idle
25-Nov-53	56	4,948				8.5	Idle
26-Nov-53	57	4,948				8.5	Idle
27-Nov-53	58	4,948				8.5	Idle
28-Nov-53	59	4,948				8.5	Idle
29-Nov-53	60	4,948				8.5	Idle
30-Nov-53	61	4,948				8.5	Idle
1-Dec-53	62	4,948				8.5	Idle
2-Dec-53	63	4,948				8.5	Idle
3-Dec-53	64	4,948				8.5	Idle
4-Dec-53	65	4,948				8.5	Idle
5-Dec-53	66	4,948				8.5	Idle
6-Dec-53	67	4,948				8.5	Idle
7-Dec-53	68	4,948				8.5	Idle
8-Dec-53	69	4,948				8.5	Idle
9-Dec-53	70	4,948				8.5	Idle
10-Dec-53	71	4,948				8.5	Idle
11-Dec-53	72	4,948				8.5	Idle
12-Dec-53	73	4,948				8.5	Idle
13-Dec-53	74	4,948				8.5	Idle
14-Dec-53	75	4,948				8.5	Idle
15-Dec-53	76	4,948				8.5	Idle
16-Dec-53	77	4,948				8.5	Idle
17-Dec-53	78	4,948				8.5	Idle
18-Dec-53	79	4,948				8.5	Idle
19-Dec-53	80	4,948				8.5	Idle
20-Dec-53	81	4,948				8.5	Idle
21-Dec-53	82	4,948				8.5	Idle
22-Dec-53	83	4,948				8.5	Idle
23-Dec-53	84	4,948				8.5	Idle

24-Dec-53	85	4,948				8.5	Idle
25-Dec-53	86	4,948				8.5	Idle
26-Dec-53	87	4,948				8.5	Idle
27-Dec-53	88	4,948				8.5	Idle
28-Dec-53	89	4,948				8.5	Idle
29-Dec-53	90	4,948				8.5	MIRU
30-Dec-53	91	4,948				8.5	MIRU
31-Dec-53	92	4,948				8.5	MIRU
1-Jan-54	93	4,948				8.5	MIRU
2-Jan-54	94	4,948				8.5	TIH to TOF at 3967'. Set cement plug 150sx Colton Slow cement + 20% sand.
3-Jan-54	95	3,830	74.0	-1,118	9.89	8.5	Tag TOC 3770'. CO to 3830'. MW 74#.
4-Jan-54	96	3,860	74.0	30	9.89	8.5	CO cement to 3860'. Run Eastman 'shoe horn type' whipstock. MW 74#.
5-Jan-54	97	3,929	73.0	69	9.76	10.625	Drilled off whipstock with 7-7/8" bit to 3878'. Opened hole to 10-5/8". Deviation 3.5 deg at 3900'. MW 73#.
6-Jan-54	98	4,139	72.0	210	9.63	10.625	Drilling
7-Jan-54	99	4,333	73.0	194	9.76	10.625	Drilling
8-Jan-54	100	4,594	75.0	261	10.03	10.625	Drilling
9-Jan-54	101	4,770		176		8.5	Drill to 4661'. Reduced hole size to 8.5". Drill to 4770'.
10-Jan-54	102					8.5	Drilling
11-Jan-54	103	4,806				8.5	Drilling
12-Jan-54	104	4,840	75.0	34	10.03	8.5	Drill to 4840'. Ran SLB logs.
13-Jan-54	105	4,840	75.0	0	10.03	10.625	Re-drill and open 8.5" hole to 10-5/8" hole at 4680'. Ran Johnson Tester. Flow test well. MW 75#.
14-Jan-54	106	4,967	76.0	127	10.16	10.625	Drilling
15-Jan-54	107	5,053	76.0	86	10.16	10.625	Drilling
16-Jan-54	108	5,160	78.0	107	10.43	10.625	Drilling
17-Jan-54	109	5,450	77.0	290	10.29	10.625	Drilling
18-Jan-54	110	5,630	78.0	180	10.43	8.5	Drilled 8.5" hole to 5630'. Ran SLB elog at 5630'. OH to 10-5/8"
19-Jan-54	111	5,645	78.0	15	10.43	8.5	Drilled 8.5" hole to 5645'. Ran Johnson test tools. Flow test well. 38MCF/day.
20-Jan-54	112	5,790	78.0	145	10.43	8.5	Drilled 8.5" hole to 5790'. Ran SLB elog at 5770'. MW 78#.
21-Jan-54	113	5,945	77.0	155	10.29	8.5	Drilled 8.5" hole to 5945'. Ran SLB elog at 5945'. MW 77#. Took sidewall samples. Open hole to 10-5/8".
22-Jan-54	114	6,005	77.0	60	10.29	8.5	Cored 8.5" hole from 5945 - 6005' (60') with conventional core barrel. Opened hole to 10-5/8".
23-Jan-54	115	6,372	78.0	367	10.43	10.625	Drilling
24-Jan-54	116	6,706	77.0	334	10.29	10.625	Drilling
25-Jan-54	117	7,111	78.0	405	10.43	10.625	Drilling
26-Jan-54	118	7,227	78.0	116	10.43	10.625	Drilling
27-Jan-54	119	7,526	78.0	299	10.43	10.625	Drilling
28-Jan-54	120	7,594	78.0	68	10.43	10.625	Drill to 7594'. Stuck pipe 138' off btm. Spot pill, came free
29-Jan-54	121	7,780	76.0	186	10.16	10.625	Drilling
30-Jan-54	122	7,897	78.0	117	10.43	10.625	Drilling
31-Jan-54	123	7,917	78.0	20	10.43	10.625	Drill to 7917'. Set whipstock at 7917' facing SE. Drill off whipstock. Drilling
1-Feb-54	124	8,030	78.0	113	10.43	10.625	
2-Feb-54	125	8,093	74.0	63	9.89	10.625	
3-Feb-54	126	8,093	76.0	0	10.16	10.625	Ream off key seat f/3800-3900'. W&R

4-Feb-54	127	8,177	79.0	84	10.56	10.625	Drilling
5-Feb-54	128	8,240	79.0	63	10.56	10.625	Drilling
6-Feb-54	129	8,373	79.0	133	10.56	10.625	Drilling
7-Feb-54	130	8,544	80.0	171	10.69	10.625	Drilling
8-Feb-54	131	8,580	80.0	36	10.69	10.625	Drilled 10-5/8" hole to 8580'. Ran SLB elogs at 8580'.
9-Feb-54	132	8,585	78.0	5	10.43	10.625	Drilled 10-5/8" hole to 8585'. MW 78#. Run 7" casing.
10-Feb-54	133	8,585	78.0	0	10.43	10.625	Ran and cmt 7.0" casing.
11-Feb-54	134	8,585	78.0	0	10.43	6.0	TIH with 3.5" DP. Tagged cement 8537'. Drilled cement to 8584'. Ran SLB Neutron and CCL to 8584'. Perforated 4 holes at 8583'.
12-Feb-54	135	8,585	76.0	0	10.16	6.0	TIH with 3.5" DP. Tagged cement 8537'. Drilled cement to 8584'. Ran SLB Neutron and CCL to 8584'. Perforated 4 holes at 8583'.
13-Feb-54	136	8,634	80.0	49	10.69	6.0	CO cement. Drilled 6" hole to 8634'. MW 80#.
14-Feb-54	137	8,749	79.0	115	10.56	6.0	**Drill to TD**. Ran SLB elog to 8749'. Reamed 6" hole to 8749'.
15-Feb-54	138	8,749					**Landed 189' of 5.5"** 20 ppf J-55 Youngstown flush joint liner at 8748'. Top of hanger at 8559'. Perforations 8592 - 8748'. Details of perforations: 120 mesh, 12 rows, 2" slots, 6" centers, 6 deg undercut by Pacific. LD DP and PU tubing.
16-Feb-54	139	8,749					Install tree and landed 2-7/8" tubing at 8540'. Displace mud with oil.
17-Feb-54	140	8,749					Swabbing well, etc
18-Feb-54	141	8,749					Swabbing well, etc
19-Feb-54	142	8,749					Swabbing well, etc
20-Feb-54	143	8,749					Release Rig

15 Appendix 5: CBL Log in 2-7/8" Tubing, 17 Feb, 2016

Below is a portion of the CBL log run in the 2-7/8" tubing after the well kill operation was compete to verify the location of the cement plug in the 2-7/8" x 7" annulus. The log shows the TOC in the annulus to be at 7,590 ft.

Company Southern California Gas Company
Well Standard Sesnon #25
Field Aliso Canyon
County Los Angeles
State California Country U.S.A.

Western Wireline

Radial Cement Bond Log
w/ Gamma Ray / CCL
(RCBL/GR/CCL)

Company Southern California Gas Company
Well Standard Sesnon #25
Field Aliso Canyon
County Los Angeles
State California Country U.S.A.

Location: API # :

SEC TWP RGE

Other Services: None

Permanent Datum	Ground Level	Elevation	2927	Elevation
Log Measured From	D.F. of 6'			K.B.
Drilling Measured From	D.F.			D.F. 2933
				G.L. 2927

Date	17-Feb-2016		
Run Number	One		
Depth Driller	3467		
Depth Logger	3196		
Bottom Logged Interval	3196		
Top Log Interval	7060		
Open Hole Size	N/A		
Type Fluid	Unknown		
Density / Viscosity	Unknown		
Max. Recorded Temp.	157.1 degF		
Estimated Cement Top	TBD		
Time Well Ready	09:30 A.M.		
Time Logger on Bottom	11:00 A.M.		
Equipment Number	206		
Location	Bakersfield		
Recorded By	D.A. Hall		
Witnessed By	See Remarks		

	Borehole Record			Tubing Record			
Run Number	Bit	From	To	Size	Weight	From	To

Casing Record	Size	Wgt/Ft	Top	Bottom
Surface String	11.75	42.0 H40	Surface	990
Prot. String	7.0	23.0 J55, 23.0 N80	Surface	8585
Production String		26.0 N80, 29.0 N80		
Liner	5.5	20.0 J55	8559	8749

<<< Fold Here >>>

All interpretations are opinions based on inferences from electrical or other measurements and we cannot and do not guarantee the accuracy or correctness of any interpretation, and we shall not, except in the case of gross or willfu negligence on our part, be liable or responsible for any loss, costs, damages, or expenses incurred or sustained by anyone resulting from any interpretation made by any of our officers, agents or employees. These interpretations are also subject to our general terms and conditions set out in our current Price Schedule.

Comments

This log was witnessed by Senior Oil and Gas Engineers Alan Walker, Scott McGurk, and Scott Walker

Log depth control used was a D.F. of 6'

Log Variables

DatabaseC:\ProgramData\Warrior\Data\socalgas_ss25_2-17-16_cbl_perf.db
Dataset field/well/run1/pass5/_vars_

Top - Bottom

PPT usec	CASEWGHT lb/ft	MAXAMPL mV	MINAMPL mV	MINATTN db/ft	SRFTEMP degF	CASETHCK in	CASEOD in
237	6.5	106.5	1	0.8	0	0	2.875

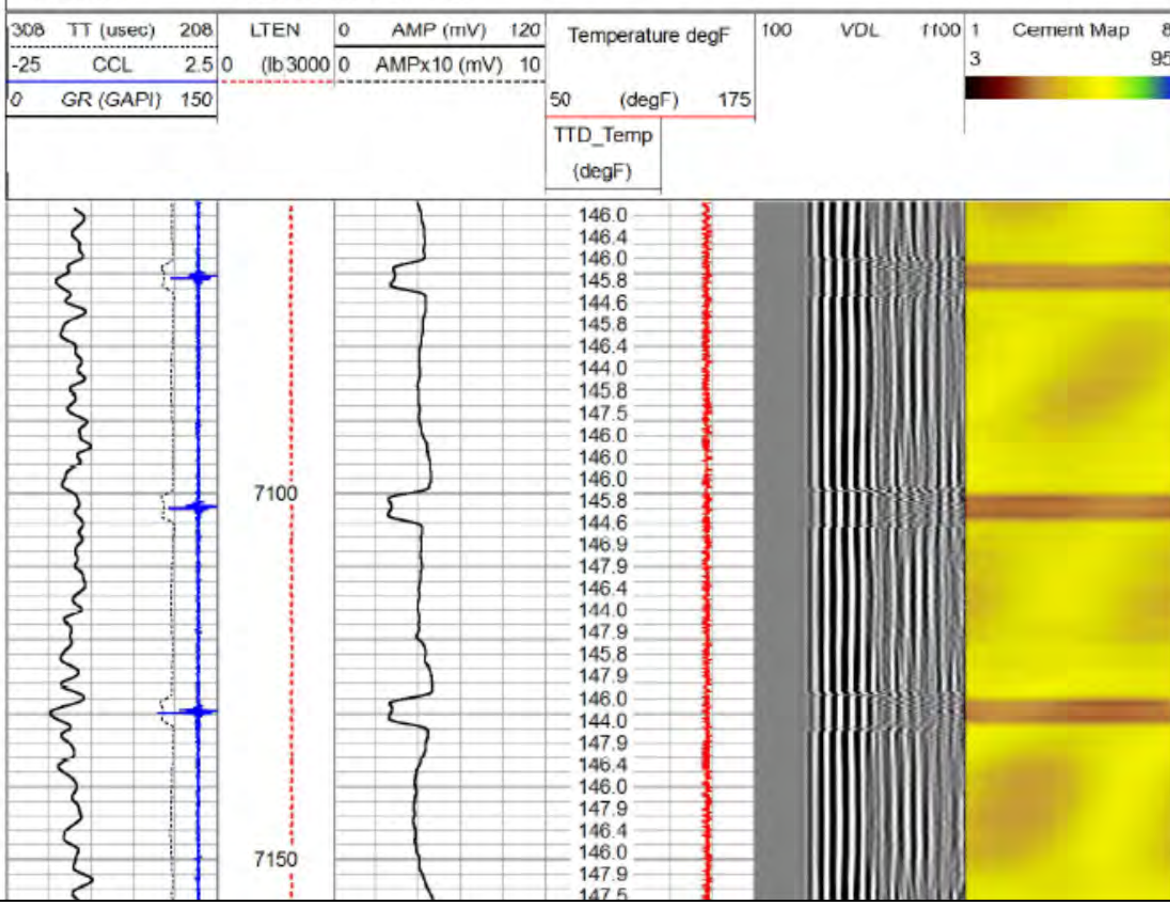
PERFS	TDEPTH ft	BOTTEMP degF	BOREID in
0	8196	100	7.875

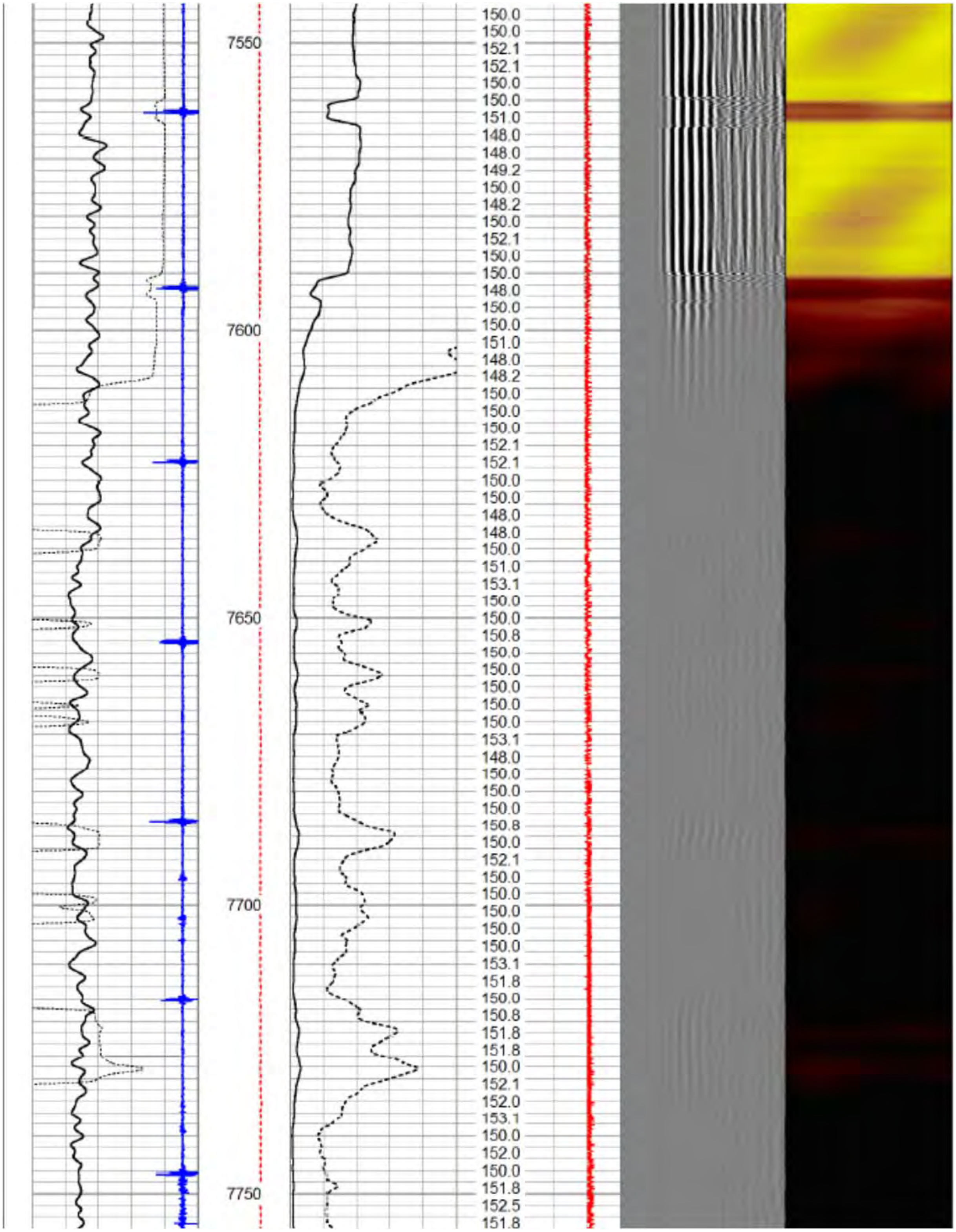
Western Wireline

Main Logging Section

5" = 100'

Database File	socalgas_ss25_2-17-16_cbl_perf.db
Dataset Pathname	pass4
Presentation Format	radii_8sec_dccl
Dataset Creation	Wed Feb 17 11:14:15 2016
Charted by	Depth in Feet scaled 1:240




7550
7600
7650
7700
7750
150.0
150.0
152.1
152.1
150.0
150.0
151.0
148.0
148.0
149.2
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148.2
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148.0
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153.1
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150.8
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148.0
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150.8
151.8
151.8
150.0
152.1
152.0
153.1
150.0
152.0
150.0
151.8
152.5
151.8

16 Appendix 6: 7" Speedtite Connection Data

Information about Speedtite connections is sparse and conflicting. However, it is clear that that it is 2-step integral upset connection that is interchangeable with Hydril's Super EU connection. The connection OD references vary depending on the information source – but the Logan book specifically mentions Speedtite by name.

1470

QUALITY YOUNGSTOWN SERVICE

CONTINENTAL-EMSCO COMPANY

CASING

SPEEDTITE CASING JOINT

Speedtite Casing Joint, proved by over 20 years of oil field application, gives full clearance with the extra strength needed to support heavy deep-well casing strings. Its two-step thread joint proved 100% pressure seal against both internal and external pressures.

Increased strength of Speedtite two-step joints over threaded and coupled joints will range from 30% to 70%. With this greater joint strength heavier casing can be run on the bottom of the string and lighter casing run on the top with ample tensile strength in all joints.

Speedtite casing has a joint O.D. approximately ⅜" greater than the O.D. of the pipe. This smaller outside dimension provides additional assurance that the pipe will go to bottom quickly. It often makes it possible to reduce the hole size and lower drilling costs.

Speedtite is recommended for its fast make-up. It is self-stabbing and self-aligning.

BUTTRESS THREAD CA

Today's drillers throughout t having their demands for better cas Youngstown Buttress Thread. As and deeper into the earth's strata, strength, due to higher tensile an comes greater and greater.

To cope with these developme
B
ch
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much less than the friction forces. T eliminates joint failure due to "jum design also does away with the var the thread out to infinity. Coupling to engage threads to the last scr section under the last engaged thre thickness. This second design fea thread strength due to full wal

Per 1960 Composite Catalogue

Speedtite

LOGAN
OIL TOOLS

String Book
Keep Your String Together!

CASING BIT SIZES AND CLEARANCES

YOUNGSTOWN SPEED TITE CASING WITH HYDRIL TWO-STEP THREADS

Casing Specifications					Bit Size and Diametrical Clearances		
Casing O.D. (in)	Casing I.D. (in)	Wt/Ft (lbs) w/Couplings	Coupling O.D. (in)	Joint I.D. (in)	Bit Size (in)	Clearance Thousandths	Clearance Nearest 64th
5-1/2	4.950	15.50	5.825	4.857	4-1/4	.107	7/64
5-1/2	4.892	17.00	5.825	4.832	4-1/4	.082	5/64
5-1/2	4.778	20.00	5.825	4.718	4-5/8	.093	3/32
5-1/2	4.670	23.00	5.825	4.610	4-1/4	.360	23/54
6-5/8	5.921	24.00	6.997	5.795	5-5/8	.170	11/64
6-5/8	5.791	28.00	6.997	5.731	5-5/8	.106	7/64
6-5/8	5.675	32.00	6.997	5.615	5-3/8	.240	15/64
7	6.366	23.00	7.369	6.216	6-1/8	.091	3/32
7	6.276	26.00	7.369	6.216	6-1/8	.091	3/32
7	6.184	29.00	7.369	6.124	6	.124	1/8
7	6.094	32.00	7.369	6.034	5-7/8	.159	5/32
7	6.004	35.00	7.369	5.944	5-5/6	.319	5/16
7	5.920	38.00	7.369	5.860	5-5/8	.235	15/64
7-5/8	6.969	26.40	8.017	6.842	6-3/4	.092	3/32
7-5/8	6.875	29.70	8.017	6.815	6-5/8	.190	3/16
7-5/8	6.765	33.70	8.017	6.705	6-5/8	.080	5/64
7-5/8	6.625	39.00	8.017	6.565	6-1/4	.315	5/16
8-5/8	7.921	32.00	9.060	7.787	7-5/8	.162	5/32
8-5/8	7.825	36.00	9.060	7.765	7-5/8	.140	9/64
8-5/8	7.725	40.00	9.060	7.665	7-3/8	.290	19/64
8-5/8	7.625	44.00	9.060	7.565	7-3/8	.190	3/16
8-5/8	7.511	49.00	9.060	7.451	7-3/8	.076	5/64
9-5/8	8.835	40.00	10.097	8.695	8-1/2	.195	3/16
9-5/8	8.755	43.50	10.097	8.695	8-1/2	.195	3/16
9-5/8	8.681	47.00	10.097	8.621	8-1/2	.121	1/8
9-5/8	8.535	53.50	10.097	8.475	8-3/8	.100	3/32

Per Logan String Book, 2015

From what I see this is a type of integral upset connection with 2 steps and round thread profile. Upset OD is 7,444 in.

Per Tenaris-Hydril conversation, June 2016

Working under pressure is our business!

CASING CONNECTIONS

Fig. A-16—Hydril "Super EU" External Upset Connection for external upset casing.

HYDRIL "SUPER EU" CASING CONNECTION

(Patented)

The Hydril "Super EU" Casing Connection is applied to upset casing for deep wells and high-pressure service. The upset thickens the joint sections to develop high strength and maximum resistance to handling damage. The multiple shoulders provide high torque capacity for best assurance of successful casing completions under all conditions.

With the two-step thread, two threads are made up simultaneously. This reduces makeup time and casing running time. Threads are cut without a thread taper, so connections are free-running; that is, there is no thread standoff at hand-tight makeup, and no forced fits between the pin and box threads.

The Hydril "Super EU" connection incorporates Hydril's high pressure seals as shown on Page 2346, Fig. A-13 and A-14, and seals against both internal and external pressure. As the thread is run up, the inside seal contacts first, and a space remains at the outside shoulder which when closed by tonging, engages the outside seal. The positive shouldering action of Hydril Super "EU" Casing Connections is a safeguard against overtonging.

Hydril "Super EU" Casing Connections are self-stabbing and self-aligning because the two straight threads on the pin pilot themselves into mating box counterbores, thereby aligning themselves. These connections are not susceptible to cross-threading, and strings can be broken out and rerun with ease. Their outstanding ability to seal pressure-tight assures endurance for repeated makeups.

Table No. A-9—HYDRIL "SUPER EU" CASING CONNECTION

All Hydril "Super EU" casing threads of a size are interchangeable so that interconnecting substitutes are not required

SIZE O.D. & WEIGHT (Nom.)	CASING			CONNECTION				"SUPER EU" TENSION						RECOMMENDED MAKE UP TORQUE	
	Wall Thickness	I.D. (Nom.)	Drift Dia.	O.D. (Turned)	I.D. (Bored)	Pin Length	Critical Section Area ●	C-75 Minimum Parting Load	C-75 Length of String SF=1.7	N-80 Minimum Parting Load	N-80 Length of String SF=1.7	P-110 Minimum Parting Load	P-110 Length of String SF=1.6	C-75 N-80	P-110
Ins.-Lbs.	Inches	Inches	Inches	Inches	Inches	Inches	Sq. In.	1000 Lbs.	Feet	1000 Lbs.	Feet	1000 Lbs.	Feet	Ft. Lbs.	Ft. Lbs.
5—15	.296	4.408	4.283	5.370	4.328	3 1/16	4.170M	396	15,530	417	16,350	521	21,710	5,000	7,000
5—18	.362	4.276	4.151	5.420	4.196	3¼	5.056M	480	15,690	506	16,540	632	21,940	5,000	7,000
5—20.3	.408	4.184	4.059	5.420	4.104	3¼	5.564F	529	15,330	556	16,110	696	21,430	5,000	7,000
5—23.2	.478	4.044	3.919	5.420	3.964	3¼	5.564F	529	13,410	556	14,100	696	18,750	5,000	7,000
5½—15.5	.275	4.950	4.825	5.900	4.870	3 7/16	4.283M	407	15,450	.....	....	.....	....	6,000	....
5½—17	.304	4.892	4.767	5.900	4.812	3 7/16	4.725M	449	15,540	473	16,370	591	21,730	6,000	8,000
5½—20	.361	4.778	4.653	6.000	4.698	3½	5.579M	530	15,590	558	16,410	697	21,780	6,000	8,000
5½—23	.415	4.670	4.545	6.000	4.590	3½	6.368M	605	15,470	637	16,290	796	21,630	6,000	8,000
5½—26	.476	4.548	4.423	6.068	4.468	3 9/16	7.135F	678	15,340	713	16,130	892	21,440	6,000	8,000
6⅝—24	.352	5.921	5.666	7.072	5.811	3¾	6.775M	644	15,780	678	16,620	847	22,060	7,500	10,000
6⅝—28	.417	5.791	5.666	7.072	5.711	3 11/16	7.682M	730	15,340	768	16,130	960	21,430	7,500	10,000
6⅝—32	.475	5.675	5.550	7.152	5.595	3 15/16	8.714M	828	15,220	871	16,010	1,089	21,270	7,500	10,000
7—23	.317	6.366	6.151	7.444	6.256	3 11/16	6.578M	625	15,980	658	16,830	.....	....	8,500	....
7—26	.362	6.276	6.151	7.444	6.196	3¾	7.165M	681	15,410	717	16,220	896	21,540	8,500	12,000
7—29	.408	6.184	6.059	7.572	6.104	3 11/16	8.056M	765	15,520	806	16,350	1,007	21,700	8,500	12,000
7—32	.453	6.094	5.969	7.572	6.014	4	8.914M	847	15,570	891	16,380	1,114	21,760	8,500	12,000
7—35	.498	6.004	5.879	7.572	5.924	4	9.666F	918	15,430	967	16,250	1,208	21,570	8,500	12,000
7—38	.540	5.920	5.795	7.635	5.840	4	10.418F	990	15,330	1,042	16,130	1,302	21,410	8,500	12,000
7⅝—26.4	.328	6.969	6.750	8.125	6.859	4½	7.428M	706	15,730	743	16,560	.....	....	9,000	....
7⅝—29.7	.375	6.875	6.750	8.250	6.795	4½	8.115M	771	15,270	812	16,080	1,014	21,340	9,000	13,000
7⅝—33.7	.430	6.765	6.640	8.250	6.685	4¾	9.282M	882	15,390	928	16,200	1,160	21,510	9,000	13,000
7⅝—39	.500	6.625	6.500	8.250	6.545	4¾	10.739M	1,020	15,390	1,074	16,200	1,342	21,510	9,000	13,000
7⅝—45.3	.595	6.435	6.310	8.312	6.355	4¾	11.645F	1,106	14,360	1,165	15,130	1,456	20,090	9,000	13,000

For Pressure Ratings of Pipe Body, See Table No. A-19 on Page 2356

● Critical member. M—Male and F—Female.
Tension strengths calculated on: C-75=75,000 yield and 95,000 ultimate; N-80=80,000 and 100,000 ultimate; P-110=110,000 yield and 125,000 ultimate.