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Performance Analysis of Novel Metal Expandable Openhole Packers for High-Temperature Geothermal Wells: A Case Study of Utah FORGE

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ABSTRACT

Achieving short- and long-term zonal isolation in geothermal wells has previously posed significant operational challenges, particularly during high-pressure hydraulic fracturing operations and ones with extensive temperature cycling. Conventional packer designs that rely on elastomeric sealing elements often fail under high-temperature and stress-corrosion conditions. Effective zonal isolation in these environments requires tools capable of sealing under the high-pressure, high-temperature (HPHT) conditions encountered throughout the well's lifecycle. Welltec developed a novel downhole metal expandable packer (MEP) using metallic seals as part of the FORGE project. The University of Oklahoma (OU) conducted performance tests on these designs to enable precise stimulation control across multiple zones, ensuring they can withstand extreme geothermal well conditions. The assessment has focused on the performance of these innovative packers, with particular attention to their ability to endure HPHT loads over the well's operational life. The challenges conventional openhole packers face in these environments have been reviewed with their limitations. Established packer calculations have been discussed regarding the forces acting among the tubing, packer, and casing interfaces. This study plays an important role in defining the operational envelope for multi-stage packers and predicting the packer performance during hydraulic fracturing operations in geothermal wells. Case studies have been done using casing and tubing design software to evaluate the safe operating envelope of these MEPs. Comparisons have been made between the currently proposed packers and a failed cased-hole packer in the FORGE Well 16A(78)-32 during the diagnostic fracture injection test cycles (DFIT). Evaluation has been conducted on the potential benefits and challenges of incorporating expansion joints and/or seal movement allowances in order to enhance the performance and reliability in geothermal well applications.

1. INTRODUCTION

The FORGE Wells 16A and 16B have a high complexity index because of numerous factors. Some of these factors are high bottomhole temperatures (BHT) exceeding 400°F, a high inclination angle greater than 65, as well as a true vertical depth (TVD) greater than most geothermal wells, at over 8,500 ft. Additionally, these wells have a moderate horizontal section of 4,000 ft. The complexity is further increased by the inclusion of openhole and cased-hole completion intervals, caliper logs, bridge plugs, open- and cased-hole packers, hydraulic fracturing techniques, and sliding/fracturing sleeves.

The packers used in oil and gas wells have limited use in geothermal wells for zonal isolation due to the lack of their long-term resistance under elevated temperature and pressure conditions (VELÁSQUEZ et al., 2024). As a solution to previously failed cased-hole packer applications in FORGE wells, a new proposal has been made to deploy openhole metal expandable packers for stage fracturing. Welltec has designed a packer that uses metal-to-metal seals (i.e., a combination of metal membrane and reinforced PTFE) (Abid et al., 2022; VELÁSQUEZ et al., 2024). Instead of using elastomeric seals, the new packer design incorporates all-metal and PTFE seals. PTFE seals are designed to withstand hot temperatures and high pressures in aggressive environments where elastomeric seals cannot. Although some elastomeric seals may endure high-temperature environments, however, their performance longevity is limited.

Concerns about the performance of the openhole packers, which will be deployed in a rough and irregular 8-1/2" to 9" deviated granitic openhole in a geothermal well, are not new (Dreesen et al., 1988). A variety of inflatable or straddle packers have been deployed in geothermal wells with a low success rate, mostly because the elastomeric seal elements cannot endure hot temperatures and stress-corrosion environments. No traditional elastomer can deliver the extreme elongation, high-pressure sealing, and temperature swing stability required (Deng et al., 2019; Doane et al., 2012). According to Ali et al. (2023), openhole MEPs provide on-demand, high-pressure zonal isolation across varying borehole geometries, unaffected by the thermal cycles in the wellbore.

A caliper log ensures that the openhole packers are not set in excessively washed-out intervals greater than the maximum packer expansion outer diameter (OD). A designer of cased-hole packers can testify to the difficulty of qualification within a known and controlled inner diameter (ID). When considering the variations and irregularities of granitic environments, the design of openhole packers is even more challenging (Adan et al., 2015). Therefore, openhole packers necessarily require greater expansion than cased-hole packers to account for wellbore irregularities (Deng et al., 2019).

The openhole packer is one of the most critical components of the multi-stage fracturing system. The ability of a packer to set and seal, isolating the stage sleeve at both ends, determines the effectiveness of the stimulation job. The openhole isolation packers used for multi-stage fracturing operations should also be capable of high expansion to conform and seal in washouts up to 10% over the designated drilled diameter. The cyclic testing schedule should incorporate temperature swings between 140 and 437°F, as per the FORGE bottom hole conditions during stimulation. The design should also accommodate pipe movement while maintaining differential pressure to eliminate additional localized axial stress on the pipe, connections, and tool components caused by pipe cooling and ballooning during stimulation operations (Khan et al., 2020).

Throughout the well operations, tubing movement or length changes can be divided into five categories, i.e., thermal, ballooning, buckling, Hooke's law (i.e., piston), and packer setting (Lubinski & Althouse, 1962). Thermal fluctuations can cause tubing to either lengthen or shorten. Ballooning may occur because of the Poisson's effect, where differential pressure results in radial swelling or contraction. Buckling takes place when the compressive forces exceed the critical threshold (i.e., critical buckling force). These forces make the tubing bend into sinusoidal or helical shapes and thus shorten causing buckling. Finally, Hooke's law governs how the tubing responds to both direct packer loads, and piston loads created by pressure differences across the packer. Additionally, the tubing elongates under high-temperature and collapse conditions, while it shortens under low-temperature and burst conditions. Therefore, the packer load calculations include Hooke's law, friction, piston, buckling, ballooning and thermal effects, tubing-to-packer, and packer-to-casing forces, applied pick-up/slack-off forces, and axial loads above/below the packer (Hammerlindl, 1980; Kang et al., 2020; Lubinski & Althouse, 1962).

During the service life of a packer, downhole conditions can change over time due to various operations, such as injections, shut-ins, stimulations, production, and workovers. These changes in loads, and corresponding variations in pressure and temperature (i.e., changes from the initial setting conditions) can lead to significant changes in the tubing length and/or additional loads. Therefore, permanent packers are typical in successful HPHT service operations. If the packer does not allow free movement or the tubing reaches its movement limit, the expansion/contraction of the tubing string gets restricted, generating significant axial tension or compression loads on the packer. If free movement is allowed by the packer, these additional loads will not affect the packer. However, they may cause changes in the tubing length. When the tubing movement is restricted or reaches its limits, the additional load will be distributed across both the tubing and packer. If the combined load exceeds the packer's safe operating envelope, packer failures may occur. When the combined loads align in a direction that permits tubing movement, the generated forces could counteract the length change, effectively restoring the tubing to its original length (Kang et al., 2020). According to Hammerlindl (1980), the loads on the packer can be reduced by heating the injection fluid and using a smaller packer bore.

For the load analyses, a positive force indicates a downward direction, while a negative force indicates an upward direction. Similarly, a positive length change reflects tubing elongation, whereas a negative length change tubing contraction. Axial loads above and below the packer are defined as positive for tension and negative for compression (Kang et al., 2020). In this study, only some of the packer calculation equations will be provided below. However, extensive literature on the subject can be found in the works of Hammerlindl (1977), Hammerlindl (1980), and Lubinski and Althouse (1962).

The tubing-to-packer force is generated by the imposed loads that cause a change in the length of the string. These loads, which induce length changes in the tubing, result in a corresponding force from the packer that restrains this movement. In situations where the packer is latched, a seal bore (i.e., polished bore receptacle) is present, and no seal movement is permitted, the tubing-to-packer force is presented as (Kang et al., 2020):

$$F_{t2p} = F_{a+} - (A_{i+} - A_p) \times P_i + (A_{o+} - A_p) \times P_{o+} - F_{a-} + (A_{i-} - A_p) \times P_i - (A_{o-} - A_p) \times P_{o-} \tag{1}$$

Where

F_{t2p} = tubing-to-packer force (lbf)

F_{a+} = axial force on tailpipe (lbf)

F_{a-} = axial force above packer (lbf)

A_{i+} = tubing inner area below packer (in^2)

A_{i-} = tubing inner area above packer (in^2)

A_p = packer bore area (in^2)

P_i = tubing pressure (psi)

A_{o+} = tubing outer area below packer (in^2)

A_{o-} = tubing outer area above packer (in^2)

P_{o+} = annulus pressure below packer (psi)

P_{o-} = annulus pressure above packer (psi)

For the packer-to-casing force calculation, ignoring the weight of the packer, the following equation is used, where the piston force on the packer body is summed with the tubing-to-packer force (Kang et al., 2020):

$$F_{p2c} = \left(A_{c-} - A_p\right) \times P_{o-} - \left(A_{c+} - A_p\right) \times P_{o+} + F_{t2p} \quad (2)$$

Where

F_{p2c} = packer-to-casing force (lbf)

F_{t2p} = tubing-to-packer force (lbf)

A_{c+} = casing inner area below packer (in^2)

A_{c-} = casing inner area above packer (in^2)

Ap = packer bore area (in^2)

P_{o+} = annulus pressure below packer (psi)

P_{o-} = annulus pressure above packer (psi)

When an extended seal bore is necessary, an upper polished bore receptacle (PBR) is installed above the packer. The seal bore can provide a stroke of up to 30 ft, allowing for a floating seal that compensates for tubing elongation or contraction. Since the tubing will be unlatched after the packer is set in place, no residual stress will remain after the packer is hydraulically set. If the packer is unlatched, and a seal bore is present, allowing seal movements, the tubing-to-packer force can be reduced to (Kang et al., 2020):

$$F_{t2p} = F_{a+} - \left(A_{i+} - A_p\right) \times P_i + \left(A_{o+} - A_p\right) \times P_{o+} \quad (3)$$

Where

F_{t2p} = tubing-to-packer force (lbf)

F_{a+} = axial force on tailpipe (lbf)

A_{i+} = tubing inner area below packer (in^2)

A_p = packer bore area (in^2)

P_i = tubing pressure (psi)

A_{o+} = tubing outer area below packer (in^2)

P_{o+} = annulus pressure below packer (psi)

For the packer-to-casing force calculation, the same Equation 2 is used, where the piston force on the packer body is summed with the tubing-to-packer force (Equation 3).

In addition to extended seal bores, expansion joints have been commonly used in steam injection (i.e., steam-assisted gravity drainage) wells to accommodate the loads due to thermal expansion. According to Dreesen et al. (1988), the expansion joints can reduce the total load on the packer anchor by 25 to 30%, depending on the borehole size. The installation of an expansion joint can either be pinned closed or sheared and spaced out after packer installation. The expansion joint may optionally have a stop to prevent tubular jump-out. If the joint is manufactured as pinned closed, shear pin ratings must be specified. The stroke length, seal bore diameter, and installation space out (if already sheared) information are necessary for analyzing the expansion joints. Pins of the pinned expansion joint are designed to shear at a specified tubing load, whether tensile or compressive (i.e., contraction or expansion, respectively). The tubing has free movement after the pins shear until the joint closes (or jumps out) or is restrained by a no-go. The calculation for the movement of a sheared expansion joint is different from conventional tubing movement calculations since there are two piston loads, rather than just one as in the case of a free packer (Mitchell, 2007).

2. METHODOLOGY

In this application, the hydraulic packer setting mechanism has been considered and the expansion begins at 6,000 psi differential pressure through a port inside the packer. The minimum and maximum packer operating temperature ratings are 140 and 500°F, respectively.

Regarding the size of the tubing string, if it is necessary to use a 5-1/2”, flush or semi-flush connections will be needed in both injector and producer wells, and the connection performance may be of critical concern during high-pressure injection operations. As the tubing or work string has not yet been operationally chosen, a 5” tubing size was assumed for the initial analysis, which will be able to pass the drift of a 7” production casing having a nominal weight of 38.0 lbs/ft. If the packer seal bore ID is equal to the tubing OD, using a smaller packer bore can reduce the axial loads on the packer, as per Hammerlindl (1980). However, the buckling load will be higher for the smaller tubing size during hot operations.

The casing configuration in both producer and injector wells has been assumed to be the same for the sake of time, and this belongs to FORGE Well 16A (McLennan, 2022; McLennan et al., 2021; Winkler et al., 2021), as shown in Figure 1 (16A has a deeper TVD). Both Well 16A and 16B have the same size and same wall thickness as the innermost casing, which is 7” with a nominal weight of 38 lbs/ft. Figure 2 presents the casing string configuration used in this assessment, which belongs to Well 16A. An 8-1/2” openhole must be assumed as 8-5/8” in this study since the simulation could not be done with an openhole diameter larger than the drift of 7” casing string. Lastly, the cross-sectional view of the metal expandable packer is illustrated in Figure 3 (Escobar et al., 2024).

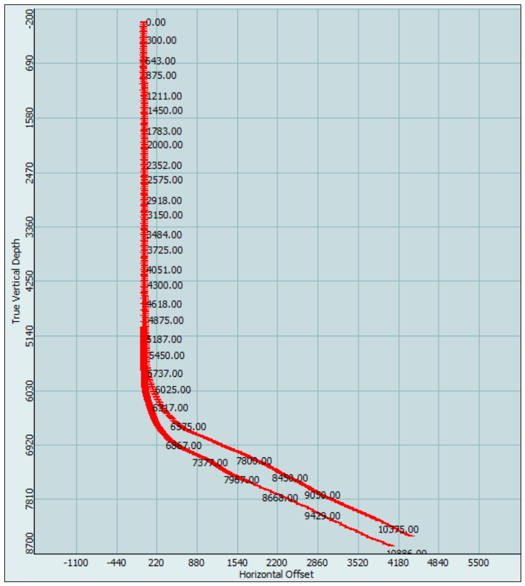

Figure 1: Section view plots for FORGE Wells 16A and 16B.

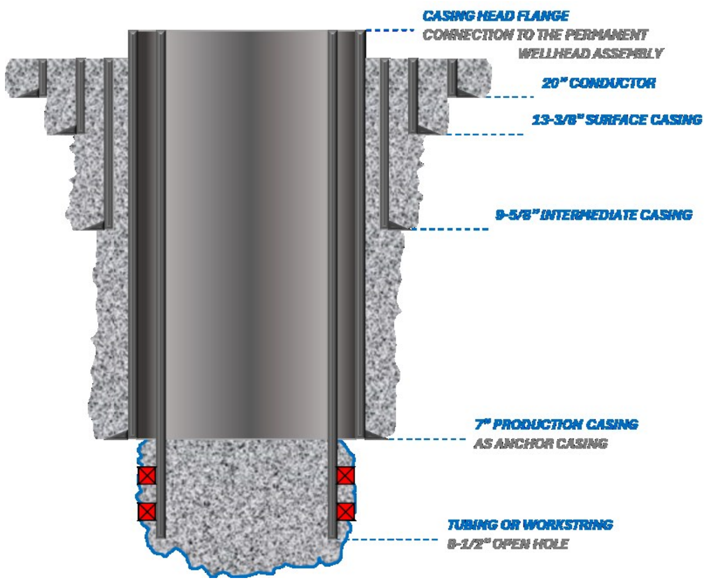

Figure 2: Well schematic showing the casing strings run and cemented in Well 16A.

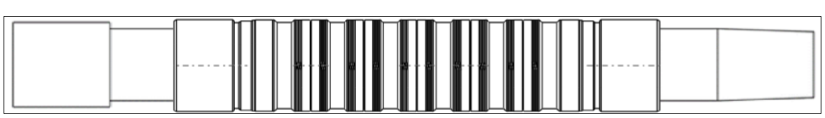

Figure 3: The schematic demonstrates the cross-sectional views of MEPs (Alvarez Escobar et al., 2024).

The schematics presented in Figure 4 represent the lower completion and details of the configuration. The left schematic highlights the lower packer. It denotes the cross-sectional areas and pressures above and below the packer. Similarly, the middle schematic does the same for the upper packer. The schematic on the right side of Figure 4 presents the analyzed configuration for the lower completion. The stimulation isolation device (SID) aligns with the flow valve at 10,885 ft MD. It was assumed that the seals of the SID are equal to the drift ID of the tubing string, which is 4”.

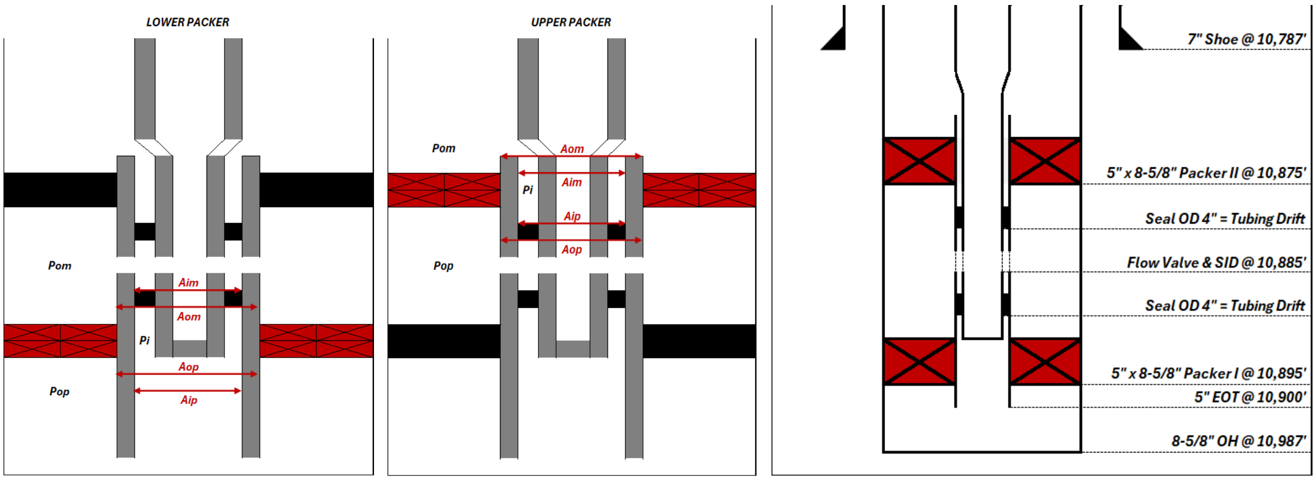

Figure 4: Packer schematics with stimulation isolation device (SID). (Left) packer I at 10,875 ft MD (or 8,530 ft TVD). (Middle) packer II at 10,895 ft MD (or 8,537 ft TVD). (Right) detailed lower completion schematics.

All the proposed tools were tested under the demanded bottomhole conditions. The MEPs, which are the most critical part of the proposed lower completion, were tested for two weeks, where the temperature was kept over 225°C (or 437°F) during the whole cycle. To test the tools’ limit under HPHT conditions, the pressure in the internal and annular areas was kept at 3,000 psi and increased to 6,000 psi three times over an hour. The pressure, temperature, and duration of the testing conditions are displayed in the chart in Figure 5 (Alvarez Escobar et al., 2024).

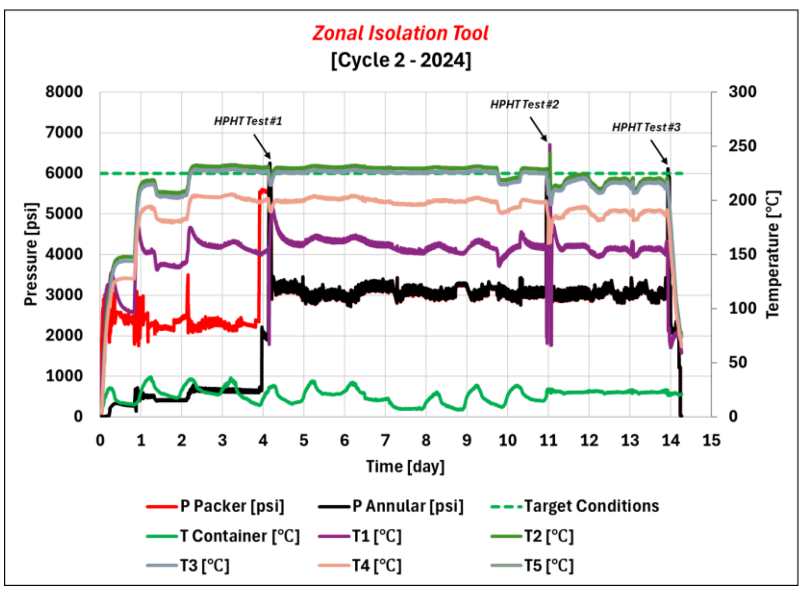

Figure 5: The chart depicts the HPHT test cycle carried out on the MEP zonal isolation tool at the OU Well Construction Technology Center (Alvarez Escobar et al., 2024).

According to the geothermal standard (Unit, 2016), axial design factors (DF) for geothermal casing strings shall be higher than the usual oil and gas applications. Throughout this study, best practices for geothermal well construction and completion have been adopted from the geothermal standard (Unit, 2016). Table 1 provides DFs for triaxial, axial, and hoop stresses. Considering the worst-case scenario, the necessary DFs for the pipe body and connection have been determined. The selected pipe body and connection DFs are provided in Table 2. For these analyses, the same DFs have been utilized for the 5” tubing string. Elasticity-based triaxial stress analysis has been performed regarding API TR 5C3 accounting for the steel temperature deration. Table 3 presents the temperature deration factors used for the analysis.

Table 1: Suggested minimum design factors for geothermal well casing strings, from the geothermal standard (Unit, 2016).

Stress Condition	Load Case	Minimum DF
Triaxial		1.25
Axial	Tensile force during running and cementing casing	1.80
	Fluid lifting force on anchor casing	1.80
	Thermal load on anchor casing (where applicable)	1.40
	Helical buckling due to self-weight plus thermal load (uncemented liner)	1.00
Hoop	Internal pressure at the shoe during cementing	1.50
	Wellhead internal pressure (shut-in steam/gas after drilling)	1.80
	Wellhead internal pressure (shut-in steam/gas after drilling) where the wellhead is fixed to the casing	1.50
	External pressure collapse (during cementing)	1.20
	External pressure collapse (during production)	1.20

Table 2: Adapted minimum DFs for connection and pipe body, considering the geothermal standard (Unit, 2016).

Pipe Body Stress Condition	Pipe Body DF	Connection Stress Condition	Connection DF
Triaxial	1.25	**Burst/Leak**	1.80
API Burst	1.80	**Tension & Compression**	1.80
API Collapse	1.20		
Axial Tension & Compression	1.80		

Table 3: Effect of temperature deration on steel properties, from the geothermal standard (Unit, 2016).

Steel Grade	Pt. 1		Pt. 2		Pt. 3		Pt. 4		Pt. 5		Pt. 6		Pt. 7	
	T (°F)	Factor	T (°F)	Factor	T (°F)	Factor	T (°F)	Factor	T (°F)	Factor	T (°F)	Factor	T (°F)	Factor
L-80	68	1.00	212	0.96	302	0.92	392	0.90	482	0.88	572	0.85	662	0.81

The first case study analyzes the performance envelope for the failed packer. Although the packer failed during DFIT (i.e., diagnostic fracture injection test) operations, a service-life model was adopted during the analysis (i.e., pre-, and post-stimulation life-of-well operations). Since detailed information about the packer specifications could not be obtained, assumptions have been made regarding the envelope limits and movement allowance. The study assumed that the packer was in a latched configuration with the tubing, preventing any tubular movement.

Next, MEPs are analyzed in terms of their performance and the expected loads during their service life. Three case studies have been performed to determine the optimum configuration in terms of tubing movement, namely, latched, seal movement, and expansion joint. After estimating the latched packer performance envelope, the next step will examine the potential reduction of the packer and tubing loads with the integration of seal movement allowances or an expansion joint to enhance the safe operating envelope. Outputs of the software will be validated in terms of tubing movement and force calculations in the end.

3. RESULTS AND DISCUSSIONS

3.1 Failed Packer Performance Envelope (Latched)

Although the main objective was to obtain the packer envelopes under stage pump-in, shut-in, and flowback, additional loads from long-term production and injection were also modeled for validation. Cold evacuation was not considered, assuming the injection fluid would always be logistically ready to fill the well. During the actual DFIT operations in Well 16A, the cased-hole packer failed. It was confirmed near the end of the DFIT cycles that the packing element was not sealing. Therefore, after the DFIT, all cased-hole operations were done without a packer but with a bridge plug. Using the same operational data, the failed packer was modeled for envelope root cause analysis. The envelope shown does not exactly correspond to the failed packer (Figure 6). However, justification was made in a way that if the 5” 21.4 lbs/ft P-110 tubing has a 689k lbf axial rating, considering a 1.8 DF would reduce the API tension and compression to below 400k lbf. Adding further safety margin led to the adoption of a 300k lbf tubing-to-packer force tensile-compressive limit. On the other hand, the packer should have at least a 6,000-psi differential rating to successfully isolate and allow operations to be performed. It was also assumed that whenever there is 6,000 psi pressure from below the packer, the tensile force limit would further reduce (i.e., upper right quadrant of the envelope). Similarly, a 6,000-psi pressure from above the packer would reduce the compressive force limit. Typically, packers cannot have perfectly rectangular envelopes as the tensile forces on the string increase, pulling the string upwards, higher pressure from below could damage the packing element and potentially compromise the sealing capability. Similarly, when compressive forces on the string increase, higher pressure from above or evacuation below could lead to the same issues.

The loads have been color-coded to understand the operational sequence. Green colors represent the operations that have been done successfully (i.e., setting, minifrac pump-in, and shut-in). The packer failed during DFIT operations, and therefore, they are colored red. Further operations have not been performed because of the leakage and thus colored grey. The left side of Figure 6 represents the packer performance envelope for the tubing-to-packer forces (i.e., T2P), while the right side of Figure 6 represents the packer-to-casing forces (P2C). The tubing-to-packer force is a combination of the axial forces immediately above and below the packer, along with the effect of differential pressures on the sealing mechanism. Similarly, the packer-to-casing force represents the upward pull (i.e., tensile) and downward push (i.e., compressive) forces. For visualization, it was assumed that P2C limits would be the same as the T2P envelope ratings. However, it is important to note that typically there is not any P2C envelope required for analysis. These forces are a combination of the force imparted to the packer by the tubing and the force resulting from the differential pressure on the external seal element. It is assumed that the higher P2C exceeding the limits would slide the packer which can be followed by tubing buckling if it is fixed at the hanger.

It is important to emphasize that the minifrac and DFIT operations do not impose the worst-case loads in terms of pressure and temperature. However, it was confirmed that the packer failed during the DFIT, and after the DFIT, all cased-hole stimulation operations were done without a packer but with a bridge plug. Considering that the DFIT operations were imposing up to 100k lbf tensile T2P force and 4,000 psi differential from below, which are lower than the limits, there is a high chance that the packer itself was mechanically performing in terms of tubular integrity. However, high temperatures may have deteriorated the sealing element in the presence of an upward pull force of more than 100k lbf. This can be observed in the P2C plot on the right side of Figure 6 (red triangles). Since P2C accounts for the piston force across the packing element, the differential from below leads to the operating points sliding slightly to the tensile region (Figure 6, right). Even if the elastomeric integrity were preserved, there is a high chance that the tubular integrity would be compromised during stage I pump-in (grey star in Figure 6, left). Additionally, the same load will lead to the highest sliding-up forces over the packing element if these represent the “actual” ratings of the failed packer.

Figure 7 presents the von Mises envelope (VME) for the tubing string. The yield strength of the tubing has to be at least 110 ksi and should have a relatively thicker wall to endure the loading conditions. This corresponds to a 5” 21.4 lbs/ft P-110 grade tubing to stay inside safe operating conditions. Even with this configuration incorporating a 100% performance proprietary connection, the tubing connection might jump out during stage I pump-in (pink line in Figure 7). Both sinusoidal and helical buckling are predicted with this latched configuration.

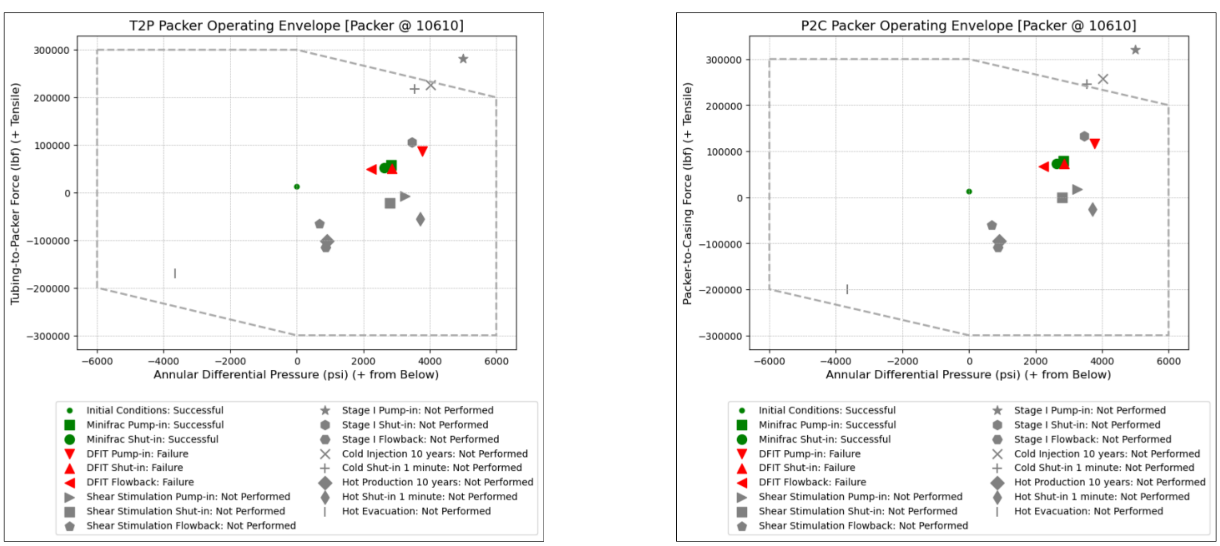

Figure 6: Failed packer operating envelopes for the stimulation and life-of-well operations. (Left) tubing-to-packer force. (Right) packer-to-casing force.

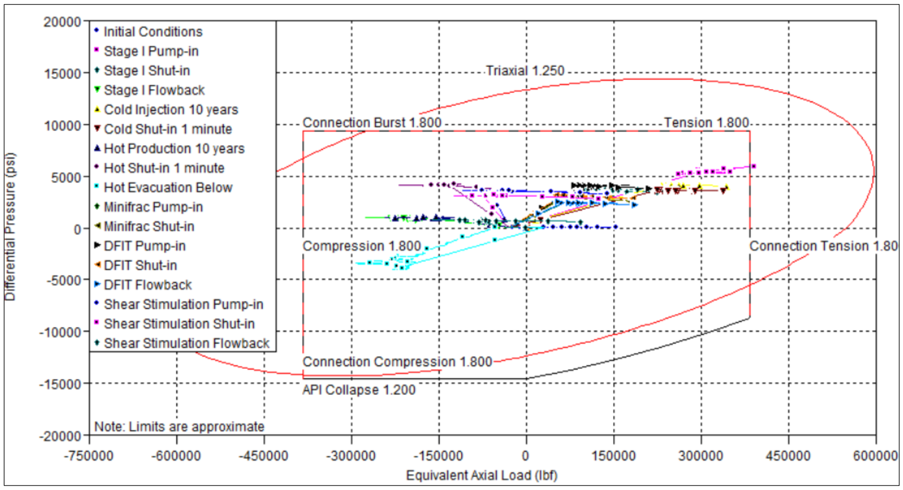

Figure 7: 5” 21.4 ppf P-110 proprietary connection tubing string VME envelope with a latched packer.

3.2 Latched MEP Performance Envelope

Firstly, to stay above the minimum operating temperature rating of 140°F, the packer demands surface injection temperatures in the range of 70-80°F. Otherwise, the temperature at the packers may fall below the minimum operating temperature during the extended duration of cold pump-in. The latter may not be apparent during the initial stages of fracture stimulation, however, as the flow rate increases in subsequent treatment cycles, the environment around the packer may get cooler than predicted. Moreover, the effect of cooling may not be obvious during the initial cycles, but rather near the end of the frac stages.

The grey-colored dashed line in Figure 8, which represents the required operating envelope for the latched MEPs is taken the same as the one for the failed packer discussed previously. In this scenario, the tubing movement is not allowed. It can be seen from the left side of Figure 8, that the cold pump-in and shut-in loads demand a tensile limit of at least 150k lbf for both the upper and lower packers regarding T2P forces. Namely, stage I pump-in, cold injection, and cold shut-in loads are tensile for both packers, tending to worsen the upward pull force on the packers. Similarly, stage I flowback and hot production loads are compressive for both packers, again worsening the downward push force on the packers. Note that the T2P force is the difference between the axial load below and the axial load above.

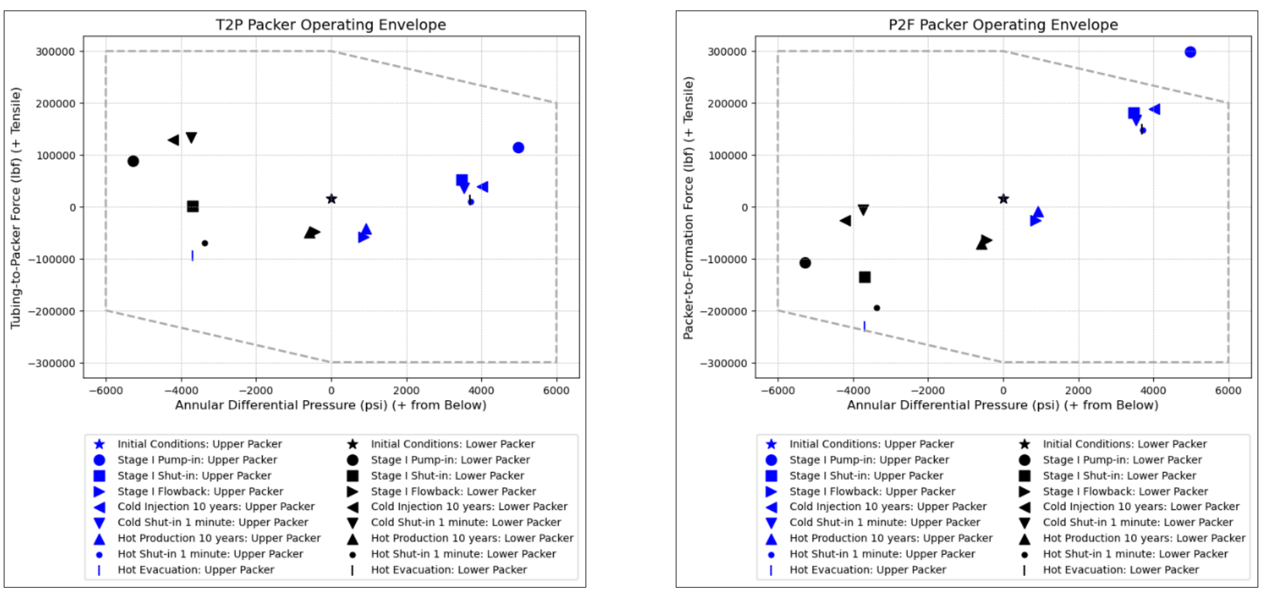

Figure 8: Latched MEP operating envelopes for the life-of-well operations. (Left) tubing-to-packer force. (Right) packer-to-casing force.

Regarding the packer-to-formation forces (P2F) in Figure 8 (right), these forces are a combination of the force imparted to the packer by the tubing and the force resulting from the differential pressure on the external seal element (i.e., piston force). Examining the envelope, there are some critical operations. To give some examples, the P2F for stage I flowback and hot production are compressive for both packers, exerting a downward push force between the packer body and formation. It should be noted that these forces are packer-to-formation in nature, which means the formation integrity may be mechanically compromised due to the friction between the packing element and the open hole wall, and eventually the packer may slide if the combined P2F is higher than the limit. If the combined P2F is tensile, the pull force will slide the packers up, whereas compressive P2F acts in the opposite direction leading to a push force (or set down) sliding the packers down. It can also be assumed that the pressure differential will balance each other as well. If there is a tensile P2F higher than the actual drag force, the problem can be solved by increasing the injection temperatures, which will lead to lesser tubing thermal contraction. However, the only solution to prevent higher compressive P2F forces is to adopt a tubing movement mechanism.

Comparing the two scenarios, namely the failed packer, and multiple openhole packers, gives some insights (Figures 6 and 8, left). The T2P forces are lower for both MEPs compared to the failed packer. This may also show the benefit of using multiple openhole packers and injecting in-between them using a flow valve. Similarly, it shows a disadvantage of using a single packer for the cold pump-in operations, because these were exerting exceedingly high T2P forces on the single packer configuration on the upper right quadrant (Figure 6, left). Manufacturing a packer with a tensile rating of 300k lbf T2P force at the highest differential pressure rating from the bottom would be more challenging. Regarding the similarities between this and the previous case studies, both helical and sinusoidal buckling are predicted to happen with the latched packer configuration, especially during the hot flowback operation. It should also be noted that the tubing string was chosen to be the same as in the previous case study, and it had the same VME envelope that is presented in Figure 7.

3.3 MEP Performance Envelope with Seal Movement Allowance (Un-Latched)

It is better to cross-examine two separate wells, namely the injector and the producer well. In the injector well, the operator will perform cold injection, while in the producer well, hot production. Unfortunately, there are two concerns about this kind of application, namely, buckling in the producer, and packer failure in both wells. As seen in the previous case studies, the axial loads in terms of T2P and P2F are quite high for MEPs in the latched configuration. The nature of these long-term production and injection operations imposes significant axial loads on the tubing string if it is fixed both at the hanger and at the packers. One way to prevent severe tubular failures without compromising the desired operational temperatures is to allow movement. There are several ways to achieve tubing movement, when necessary, regardless of the type of load, such as piston force, buckling, ballooning, and thermal effects. One approach is to deploy the packer as un-latched. Given that the tubing will be hung at the wellhead and assumed to be fixed by the hanger, allowing seal movement inside the PBR may reduce the severity of the axial loads. The tubing would then have movement capability, either free or limited. An upward no-go mechanism can be employed to prevent the tubing string assembly from moving out of the PBR. Additionally, a downward no-go mechanism should also be adopted to prevent excessive downward movement. At the very least, a packer PBR without a downward no-go mechanism would be rare to be applied in oil and gas applications. Another approach to reducing the high axial forces is to deploy an expansion joint (or travel joint) with a tubing anchor (or packer) above the uppermost packer and let it serve this purpose. When the expansion joint is deployed, the tubing below the joint would typically be latched to the openhole packers. If the distance between the expansion joint and the MEPs is not too large, there should not be buckling between them due to thermal expansion during hot operations. With enough stroke capacity, the expansion joint could also prevent any tensile failures due to thermal contraction during cold operations. Typically, the expansion joint would have a shear mechanism with shear pins that shear at a predetermined force. Extreme operational loads demanding elongation or contraction (i.e., not only thermal, but also piston, ballooning, and buckling) would exceed the rating of the shear pins and initiate the movement inside the travel joint. Given the nature of this geothermal application, the tubing string would both elongate and contract in both the injector and producer well. For example, during the stimulation in the injector well, a significant temperature swing may happen from the end of the cold pump-in to the beginning of the hot flowback. Similarly, in the producer well, there may be a need to quench the well for well control or workover purposes.

Push tests have been performed for MEPs while they were in the expanded (i.e., set) position. The push force required to slide the packer was 41k lbf for a single packer, and theoretically, it is 82k lbf for two packers. Based on the previous analysis that shows the latched configuration for both MEPs, the T2P forces were higher than the tested push force. Therefore, it must be identified how much length change should be permitted to reduce the axial loads on the packers, and eventually the corresponding P2F forces. To identify how long the seal movement should be allowed, a length change calculation for the tubing string should be performed under the corresponding load conditions. The length changes were also hand-calculated to validate the simulation results. Figure 9 presents the length change summary for the so-called operations for MEPs (Table 4 in Appendix). It can be confirmed that at least 10 ft of upward and downward movement should be allowed to prevent residual axial forces acting on the packers. There are some differences between the hand-calculated and simulated length changes, however, these are not significant enough. The simulation considers both upward and downward no-go mechanisms as well. The T2P forces have been simulated with the movement allowance inside the extended PBR of MEPs and the results are shown in Figure 10. It can be understood that with the help of a 10 ft up/down seal movement allowance, the T2P forces (i.e., all being 0 lbf) do not impact the P2F forces. The P2F forces would only be impacted by the forces acting on the packer base pipe and piston forces in between the packers. There is no occurrence of buckling, except for full hot evacuation, where just sinusoidal buckling may occur down near the packers. Although there is no guarantee that buckling will not occur under high-pressure hot shut-in operation, this application is a doublet pair where the pressure is built by the injection well BHP. The analysis assumed a worst-case hot shut-in where the tubing head pressure was 3,500 psi due to thermal pressure build-up. However, this can be managed to a lower value by bleeding the well.

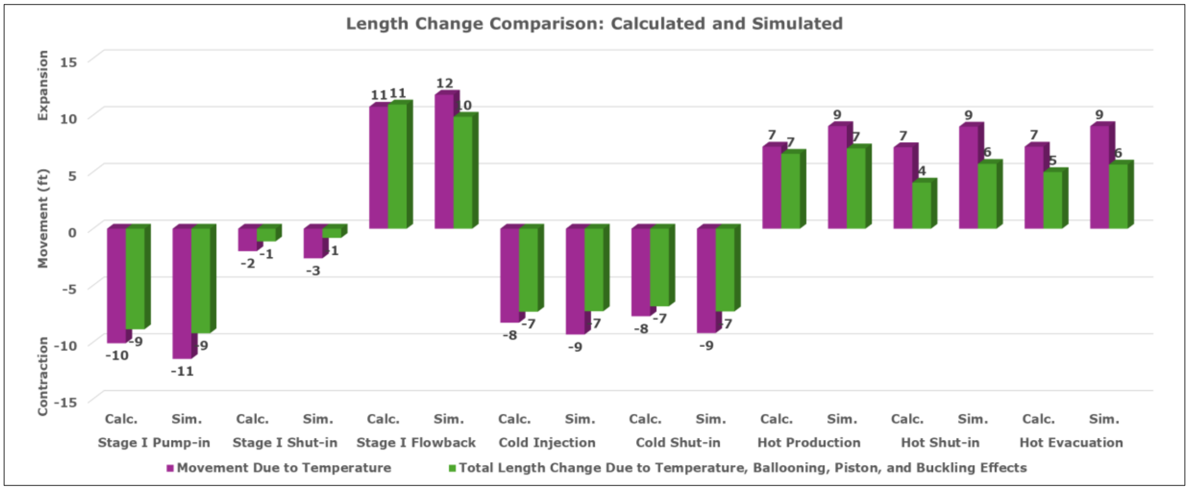

Figure 9: Tubing thermal and total length change summary for the simulated life-of-well operations.

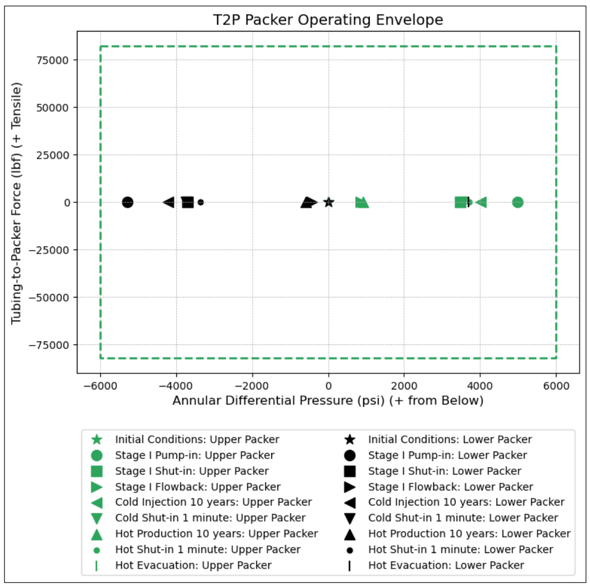

Figure 10: MEP T2P operating envelope for the life-of-well operations with seal movement allowance.

The P2F forces have been hand-calculated by adding the corresponding piston force between the packers and T2P forces under each loading (Figure 11). Since T2P forces would be 0 lbf, the P2F forces only originate from the piston forces due to pressure differential above/below the packer (Equation 2). Since the hand calculation used a constant hydrostatic pressure gradient, the combined P2F is constant and equal to 123 lbf (Table 5 in Appendix). However, the simulation accounts for the pressure gradient changes as a function of temperature and depth, resulting in higher combined P2F forces. It should be noted that hand-calculation adopted a vertical well approach having a tubing length of 10,900 ft. Even with this approach, the difference between upper and lower P2F forces is not greater than the simulation results to be of significance. Only for stage I pump-in, there is a considerable difference between the hand-calculated and simulated results, and this is because the hand-calculation considered the differential pressure to be around 5,800 psi, while the simulation did not calculate it to be more than 5,300 psi due to the reduction in fluid weight downhole (i.e., 8.33 ppg water was used as fracturing fluid). Finally, the combined P2F, according to the simulation results, which is the most important output, is lower than 82k lbf. Although the P2F for a single packer is higher than 41k lbf (push test for a single packer), the corresponding force on the other packer of the pair is the same and in the reverse direction. This leads to a balance in the P2F forces and lowers the combined push/pull force. Thus, it is not expected that any packer sliding motion downhole will be observed during these operations.

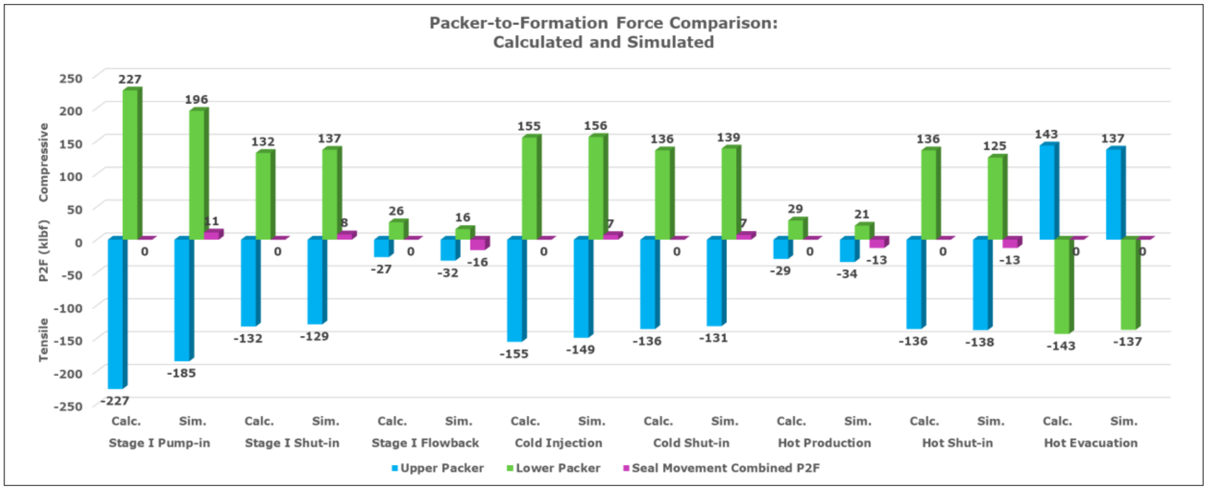

Figure 11: P2F force summary for the simulated life-of-well operations with PBR seal movement.

Figure 12 presents the VME envelope for the tubing string under the corresponding load conditions. Even with this number of higher DFs, L-80 tubing can perform well with the help of a 10 ft up/down seal movement allowance inside the packers' extended PBR. It should be noted that with the previous latched condition, even P-110 grade tubing (i.e., the same wall thickness as 21.4 ppf) had a slight chance of connection jumping out.

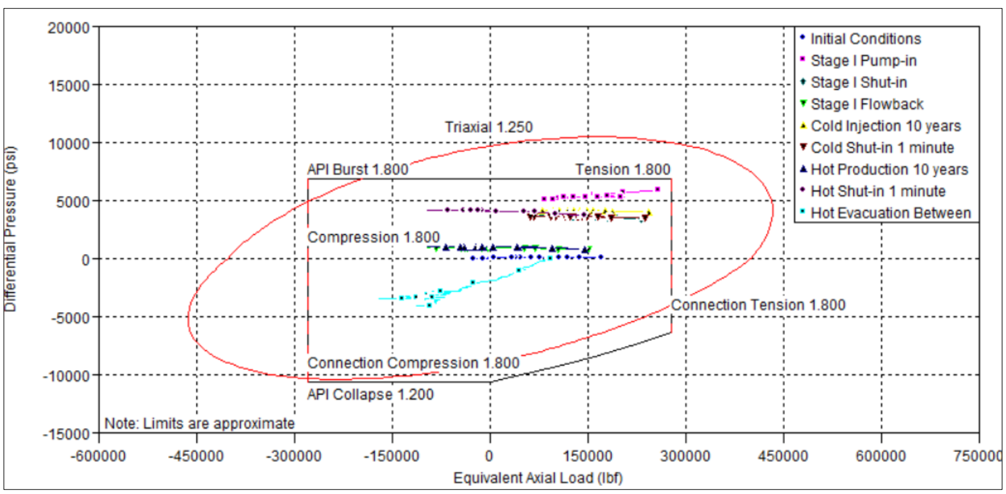

Figure 12: 5" 21.4 ppf L-80 proprietary connection tubing string VME envelope with 10 ft up/down seal movement allowance.

3.4 MEP Performance Envelope with Expansion Joint (Latched)

Finally, an expansion joint was analyzed in terms of its capability to reduce the packer loads. Since the shoe of the 7" casing was set at 10,787 ft MD, the anchor packer of the expansion joint was simulated to be above the shoe and inside the cased hole. The usage of an anchor packer or tubing anchor is necessary to fix and allow the expansion joint to perform movement. The anchor packer was simulated at a depth of 10,765 ft MD to incorporate most of the tubing length changes. The next decision is whether to allow movement inside the MEPs or not. Both scenarios have been simulated, and it was understood that even though there is an expansion joint permitting 10 ft up/down tubing length change, fixing the lower part of the tubing at the packer would not reduce the packer loads or prevent buckling issues. Therefore, a small movement was allowed (i.e., 1 ft up/down) inside the openhole MEPs to account for the tubing length changes from 10,765 ft to 10,875 ft MD.

The usage of an expansion joint inside the 7" cased-hole resulted in minimum buckling issues like the previous case study of extended PBR seal movement allowance. Figure 13 shows that L-80 grade tubing can still be safely used for the implementation of life-of-well operations.

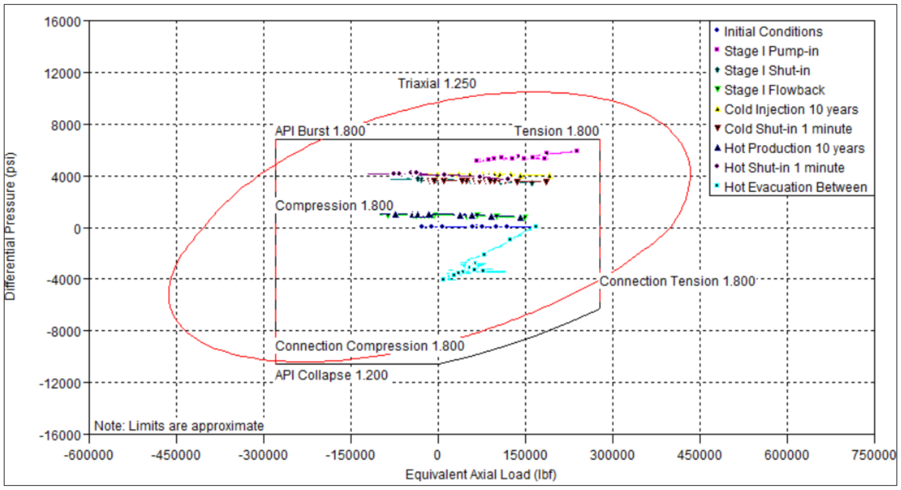

Figure 13: 5" 21.4 ppf L-80 proprietary connection tubing string VME envelope with 10 ft up/down stroke expansion joint and 1 ft up/down seal movement inside MEP PBR.

Figure 14 in the Appendix presents the comparison of combined P2F for MEPs considering two scenarios, namely, expansion joint, and PBR seal movement (Table 6 in Appendix). It can be observed that both scenarios can be acceptable since none of these loads exceed the 82k lbf push force rating of the dual MEP system. However, it should be noted that the usage of expansion does not favor the user considerably if the rest of the lower part of the tubing is fixed at the packer. To zero the T2P forces and eliminate their contribution to P2F, there must be at least around 1 ft up/down seal movement allowance inside the MEP PBR.

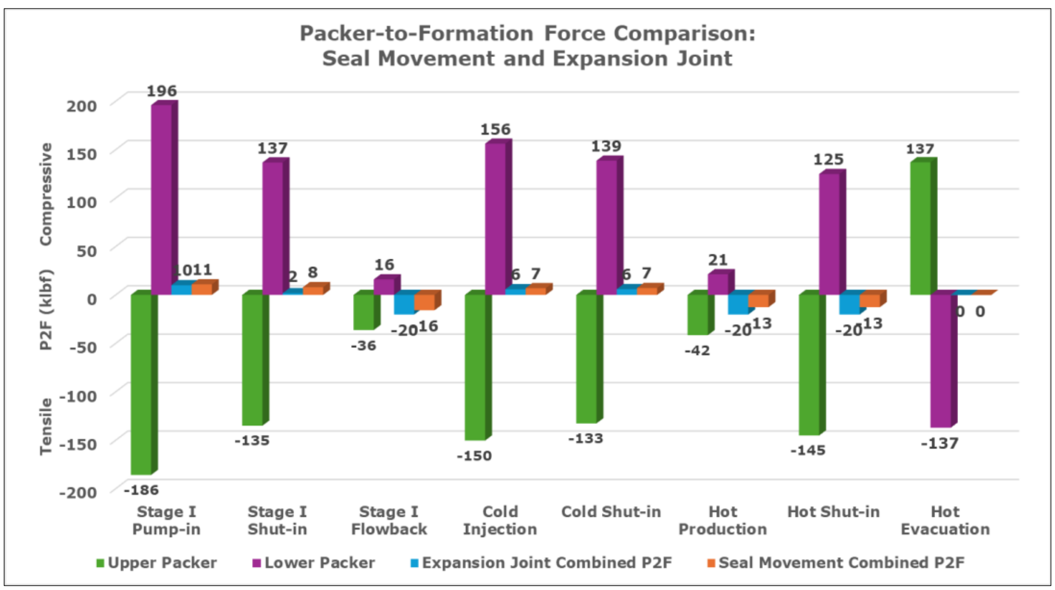

Figure 14: P2F force summary for the simulated life-of-well operations. The figure presents the combined P2F for two scenarios, namely, the expansion joint and seal movement discussed previously.

4. CONCLUSIONS

This study analyzed several important aspects of zonal isolation and packer performance to optimize the tubing string integrity and packer performance under changing downhole conditions at the FORGE site. A large portion of the study focused on generating tubing-to-packer and packer-to-formation envelopes, comparing latched, seal movement, and expansion joint scenarios. Although the packer-to-formation envelopes are not typically considered by the well designers during packer selection, this study found it beneficial to analyze the so-called loads to validate the performance in terms of push/pull force test limits.

The study revisited the failed packer used during DFIT operations. The assessment highlighted the compact nature of the performance envelope for that packer. Yet, it still failed due to elastomer failure because the DFIT axial loads on the packer were confirmed to be not significant.

The analysis confirms that adopting no seal movement leads to higher axial loads on the packers. It was also suggested that packer-to-formation forces could potentially balance and cancel each other out when one packer exerts tensile forces, and another exerts compressive forces. On the contrary, if both MEPs exert either tensile (i.e., upward pull) or compressive (i.e., downward push or set-down) P2F forces, there may be a risk of both packers sliding upward or downward, respectively.

Even though there are a lot of advantages of multi-stage packer concepts, these packers still experience significant tensile and compressive loads during the lifecycle of the well when there is no tubing movement allowed. To mitigate these loads and ensure successful well completion, two scenarios were analyzed, i.e., allowing seal movement inside the packer PBR seal bore and using an expansion joint. The results showed that allowing seal movement was sufficient to reduce axial forces against the packers, making the use of an expansion joint unnecessary. It can be concluded that allowance of 10 ft up/down seal movement inside the MEP extended PBR is a practical solution to manage high axial loads, and minimizes the risks associated with buckling and excessive stress on the tubing string and packers.

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APPENDIX

Table 4: Tubing length change summary for the simulated life-of-well operations.

Load	Stage I Pump-in		Stage I Shut-in		Stage I Flowback		Cold Injection		Cold Shut-in		Hot Production		Hot Shut-in		Hot Evacuation	
Movement	Calc.	Sim.	Calc.	Sim.	Calc.	Sim.	Calc.	Sim.	Calc.	Sim.	Calc.	Sim.	Calc.	Sim.	Calc.	Sim.
Temperature, ft	-10.1	-11.5	-2.0	-2.6	10.7	11.8	-8.3	-9.3	-7.7	-9.2	7.2	9.0	7.2	9.0	7.2	9.0
Ballooning, ft	-2.7	-2.5	-1.6	-1.6	-0.3	-0.4	-1.9	-1.9	-1.6	-1.6	-0.3	-0.4	-1.6	-1.7	0.9	1.0
Piston Effect, ft	4.5	4.8	2.6	3.4	0.5	-1.5	3.1	3.9	2.7	3.5	-0.3	-1.5	-1.3	-1.6	-2.9	-4.4
Buckling Effect, ft	-0.6	0.0	-0.2	0.0	0.0	0.0	-0.3	0.0	-0.2	0.0	0.0	0.0	-0.2	0.0	-0.2	0.0
Total, ft	-8.9	-9.2	-1.1	-0.8	10.9	9.9	-7.3	-7.3	-6.8	-7.3	6.6	7.1	4.1	5.7	5.0	5.7
Negative values indicate contraction.																
Calc. = hand calculation.																
Sim. = software simulation.																

Table 5: P2F force summary for the simulated life-of-well operations with PBR seal movement.

Load	Stage I Pump-in		Stage I Shut-in		Stage I Flowback		Cold Injection		Cold Shut-in		Hot Production		Hot Shut-in		Hot Evacuation	
Packer Loads	Calc.	Sim.	Calc.	Sim.	Calc.	Sim.	Calc.	Sim.	Calc.	Sim.	Calc.	Sim.	Calc.	Sim.	Calc.	Sim.
Upper P2F, lbf	-227,077	-184,990	-132,038	-128,743	-26,526	-31,912	-155,313	-149,194	-135,917	-131,490	-29,241	-34,003	-135,917	-137,502	143,184	136,972
Lower P2F, lbf	226,954	195,896	131,916	136,731	26,403	16,064	155,190	156,180	135,795	138,616	29,119	21,348	135,795	124,854	-143,306	-137,095
Combined P2F, lbf	-123	10,906	-123	7,988	-123	-15,848	-123	6,986	-123	7,126	-123	-12,655	-123	-12,648	-123	-123
Negative values are in the upward direction (or tensile).																
Calc. = hand calculation.																
Sim. = software simulation.																

Table 6: P2F force summary for the simulated life-of-well operations. The table presents the combined P2F for two scenarios, namely, the expansion joint and seal movement discussed previously.

Load	Stage I Pump-in	Stage I Shut-in	Stage I Flowback	Cold Injection	Cold Shut-in	Hot Production	Hot Shut-in	Hot Evacuation
Packer Loads	Sim.	Sim.	Sim.	Sim.	Sim.	Sim.	Sim.	Sim.
Upper P2F, lbf	-185,864	-134,996	-36,240	-150,343	-132,648	-41,592	-145,098	136,972
Lower P2F, lbf	195,914	136,748	16,058	156,184	138,620	21,344	124,849	-137,095
EJ Combined P2F, lbf	10,050	1,752	-20,182	5,841	5,972	-20,248	-20,249	-123
SM Combined P2F, lbf	10,906	7,988	-15,848	6,986	7,126	-12,655	-12,648	-123
Negative values are in the upward direction (or tensile).								
EJ = expansion joint.								
SM = seal movement.								
Sim. = software simulation.								