Resilient Cement used for Steam Well Completions Improves Heavy Oil Field-Development Economics: Case History

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Abstract

Heavy oil accounts for several trillion barrels of oil-in-place reserves and therefore its development has been on the forefront for many operators worldwide. Steam stimulation is one of the most prevalent methods for producing heavy oil where steam is directly injected into the formation and, as the oil absorbs heat from the steam, the viscosity decreases, allowing flow to occur. Both proper zonal isolation and cement-sheath integrity are necessary for conformance control of steam injections into zones of interest.

This case-history paper discusses the development of the heavy-oil Issaran field in Egypt. The plan was to drill 250 vertical wells and put them on a “cyclic-steam” production schedule. The investment was significant and, to make it economically feasible, each well needed to deliver its capacity after steaming. But, steam breakthrough occurred through the surface-casing annulus, rendering many wells ineffective and useless; the loss of cement integrity resulted in loss of production and, in turn, loss of revenue.

Cement resiliency is acknowledged as a critical factor for cementing “cyclic-steaming” wells because conventional cement designs might not stand up to the severe temperature fluctuations that such wells experience—a high of 450 to 600°F while steaming, and as low as 120°F (normal wellbore temperature) during the final stages of oil production. For any type of cement design to work, its effective placement is paramount; complete annular fill-up is recommended to help ensure an annular seal. This case history provides a discussion of the well design and optimized slurry properties to meet well conditions. Post-cementing field results are provided that validate the success of the cementing process and show the project to be economically feasible.

Background

The Issaran oilfield is located 290 km southeast of Cairo and 3 km inland from the western shore of the Gulf of Suez, covering an area of 20,000 acres. The field was discovered in 1981 (**Fig. 1**). The heavy-oil project started in 1998 between GPC (General Petroleum Company) and Scimitar Production Egypt Ltd.

The original oil in place (OOIP) at that time was 410 MM bbl, and the reserve was 0.2 MM bbl. The recovery factor was below 1%, and the daily production was 170 BOPD. The oil was 9- to 12-degree API with a viscosity of 4,000 cp at standard conditions, and the bottomhole pressure (BHP) was as low as 100 to 250 psi. The bottomhole temperature (BHT) was 120°F. Initial completions were aimed at the Nukhul and Gharandal formations (**Fig. 2**). The deeper reservoirs in the field existed at a depth of approximately 2,000 ft. “Cold production” could be achieved from these reservoirs, but it was highly dependent on identifying natural fractures in the field. However, the Upper Dolomite reservoir, at a depth of 1,000 ft, though holding huge reserves (50% of the OOIP), was essentially left untouched because it was of low productivity.

Enhanced oil-recovery studies (Elsaid et al. 2008) revealed that if the mobility of the heavy oil in the Upper Dolomite could be improved with special steam treatment, then it could achieve commercial production. A two-well pilot project using “cyclic-steam stimulation” (CSS) was implemented with promising results. Consequently, the company planned to drill 250 vertical wells and put them on a “cyclic-steam” production schedule. The targeted production forecast was 20,000 BOPD from 250 wells in three years.

Challenges

In an effort to keep costs low, the early wells were openhole completions in the Upper Dolomite reservoir, but soon the limitations of these types of completions became evident because early water breakthrough occurred, and there was no easy technique available to selectively control the water production from the 900 ft of openhole section. Following this impediment, the well designs were changed to include cemented, 7-in. casing string across the Upper Dolomite for zonal isolation.

However, the change to the cased-hole completions presented its own set of challenges, which are listed next.

(1) Low Fracture Gradient. The reservoir pressure across the upper and intra Dolomite sequences (at depths of 1,000 to 1,400 ft) was approximately 100 psi. Salt-saturated mud weighing 9.1 lbm/gal and treated with lost-circulation material was used for drilling the section. It was observed from past cement jobs that, even with an extremely low reservoir pressure, the formation could sometimes sustain a full column of 11.8-lbm/gal cement-slurry weight and other times it would not. To achieve effective zonal isolation, it was necessary to ensure that full annular cement coverage was obtained all the time.

(2) Time to CSS. Unlike the openhole completion where the operator was able to apply CSS immediately after the well was completed and get the well on production, the cemented wells required time for the cement slurry to set up and build sufficient compressive strength before CSS could be implemented. Because the formation fracture gradient was low (as discussed earlier), the slurry weight was bound to be lightweight and such conventional slurries are known to build compressive strength much slower than regular 15.8-lbm/gal slurry designs. Actually, in this case, the operator was waiting 30 days before CSS could be applied. The desire of course was to shorten the time to apply steam to the wells as much as possible.

(3) Casing Stresses. In cement-slurry designs, the general trend has been to solely focus on short-term cement-slurry fluid properties required for effective placement in the annulus, with the 24-hour compressive strength being the only “set cement” measurement taken. This short-term focus fails to consider the effect of the impact of stresses caused by changing wellbore conditions on the cement sheath during the life of the well.

In heavy-oil reservoirs where cyclic-steam injection is planned for enhanced oil recovery, the cement sheath is expected to experience extreme temperature variances anywhere from 120 to 550°F, resulting in extreme stress loads on the cement sheath. At the beginning of an injection phase, the well is rapidly heated up, which causes the casing to expand. During periods when the steam injection is halted and the well is put on production, the well cools down, which causes the pipe to contract. This contraction places additional stresses on the cement sheath. When superheated steam injection begins again, the stress cycle is repeated. If the cement sheath is not sufficiently elastic and resilient, the annular seal can fail during one of these stress cycles. Cracks and microannuli may develop in the cement sheath and act as pathways for the steam to escape. This can considerably reduce the recovery of heavy oil while posing health, safety, and environmental challenges.

Solutions

After reviewing the challenges discussed above, it was concluded that these wells required special cementing considerations. The cement slurries needed to be lightweight enough so as to be sustained in low fracture-gradient environments, additionally have the properties to control losses, build adequately fast compressive strength, and hold up to stress variations in the wellbore.

It was therefore our recommendation to use thixotropic, lightweight cement slurry designs with fibers that could help control losses. The slurry volumes would be increased by 60-80% over gauge hole volume to offset volume losses during placement, ensure adequate fill-up should the hole be washed out, and the slurry composition would be optimally designed to include various sized, special, high-strength particles that could serve as a lost circulation control net. These ingredients would not only help with lost-circulation control but provide enhanced compressive-strength development.

A finite element analysis (FEA) method was also necessary to analyze the effects of various well events and operations such as temperature changes, cement hydration, casing-pressure testing, completions, and production on the integrity of cement sheath during the life of the well. FEA can help operators design the cement sheath for common well events over the productive life of the well, which helps to maintain cement-sheath integrity throughout the well’s drilling and production phases.

Finite Element Analysis (FEA)

According to Budgell (1998), FEA is a computer-based numerical technique for calculating the strength and behavior of engineering structures. In the finite-element method, a structure, such as a cement sheath, is broken down into small elements. A simple set of equations assigned to each element describes the behavior of each as an individual. These equations are then placed into a larger set of equations that describe the behavior of the entire structure. Bosma et al. (1999) developed a mathematical model that incorporates FEA and takes into account the operational events from the time the cement slurry is pumped into the annulus until the well is abandoned. To use this model to design an annular sealant, the following information is required:

- Reservoir and uphole formation properties.
- Cement slurry and sheath properties.
- Casing properties.
- Operational details for drilling, completion, stimulation, production, and injection.

When using this solution procedure, determining the borehole condition, sealant hydration characteristics, and the resultant in-situ stresses in the sealant is important. The modelling indicates that the in-situ stress condition in the sealant affects the capability of the sealant to provide zonal isolation during the life of the well. In-situ stresses in the sealant depend on the condition during and after cement-slurry curing. The analysis evaluates the integrity of the cement-sheath matrix and also the competency of the bond between the casing/cement sheath and cement sheath/rock interfaces.

For a full analysis, the properties of rock, cement slurry, cement sheath, and casing, and the associated pressures and temperatures encountered during each operation should be defined. These definitions are then used to study the effects of different operations on the integrity of the cement sheath, rock, and casing.

Fig. 3 illustrates a well schematic. In the FEA method, the rock, cement, and casing in **Figs. 4** through **6** are divided into a finite number of parts or elements so that the governing equations can be solved (Ravi et al. 2002). These individual elements should satisfy the relationships and constraints of the original equation, and through this process, an approximation to the original equation can be found. The dimensions of the elements should be designed to help minimize error. The finite-element grid is shown in **Fig. 7**. The outer radius of the rock considered in simulation is large enough that the far-field stresses in the rock remain unchanged from the initial value of the in-situ stresses (Ravi et al. 2002). Interface elements are used to analyze the interfaces between cement sheath and casing and between cement sheath and rock. In the cement sheath, the FEA calculates the change in hoop stresses exerted by the expanding or contracting casing radius. The outer-diameter casing expansion is caused by increases in pressure and temperature on the steel of the casing. Steel is extremely predictable, and its expansion properties that result from increases in pressure and temperature are well-documented in literature (Bauld 1982).

Consider that a well operation causes expansion of the casing, which could come about from an increase in temperature and/or pressure. The casing is not free to expand without placing a force or stress on the adjacent cement sheath. This force or stress is further transposed into the cement sheath. The stress might or might not be transposed to the formation, depending on the tensile strength and ductility of the cement sheath. With very brittle cement sheath, such as conventional normal-weight cement slurries, the tensile strength could be exceeded and the sheath could crack (**Fig. 8**). Even if the propagating stress is contained in the cement sheath and the tensile strength is not exceeded, there could be plastic failure of cement sheath and/or debonding at the casing/cement sheath and/or cement sheath/rock interface (**Fig. 9**). In particular, when the pressure inside the casing is removed (as with pressure or temperature cycling), debonding could occur because the cement sheath might not be elastic enough to rebound to the contracting casing diameter and the result would be a microannulus. This same debonding can occur at the cement formation interface if the propagating stress is transposed to the formation and the formation cannot rebound to cement-sheath contraction. The result would be a microannulus at the formation face (**Fig. 10**). This process is further complicated by the eccentricity of the casing and changes in the formation. As one can see, the numerous calculations required to arrive at the final cement-sheath properties lend themselves to the computer and numerical methods, hence the need for FEA for determining the design of the cement sheath.

Cement-System Design Considerations

Cement-sheath design for heavy oil requires elastic cement sheath properties and reduced thermal conductivity. The cement sheath should be able to withstand stress loads, not only one time, but on a repetitive basis for cyclic-steam stimulation. Cyclic tests are conducted on the cement sheath to evaluate their capability to withstand cyclic loads (Ravi et al. 2004). The cement sheaths of high strength are normally brittle and do not withstand many cycles; whereas, cement sheaths with lower Young's modulus are able to withstand more cycles, some of them are able to withstand in excess of 1,000 cycles.

The following cement-system characteristics help in the long-term integrity of the cement sheath.

- Compensate for shrinkage during hydration.
- Lower Young's modulus or improved elasticity.
- Lower porosity and permeability.

Cement-Slurry Design

The cement system was optimized for the 7-in. casing to meet the above requirements. A conventional cement system at 15.8 lbm/gal could shrink anywhere from 2 to 4% under downhole conditions in the absence of surrounding fluid. The "steam-cement" slurry was optimized so that the hydration volume shrinkage was compensated. Simulations have shown that hydration volume shrinkage could have detrimental effects on the integrity of the cement sheath.

The shrinkage of "steam cement" was compensated by incorporating expansive additives and polymers to improve the elasticity of the cement sheath. These two components are able to compensate for shrinkage during hydration and also impart post-set expansion to compensate for any bulk shrinkage.

The Young's modulus of a conventional 15.8-lbm/gal cement system is about 2×10^6 psi (Ravi et al. 2004). Impact tests conducted in the lab have shown that these cement systems might not be able to withstand more than one or two impacts simulated under downhole conditions; whereas, an optimized cement system with lower Young's modulus can withstand a much larger number of simulated impacts. The addition of microspheres, fibers, and elastomers to the base slurry improved its elasticity and resilience by dropping the Young's modulus to 1.2×10^6 psi (**Table 1**) (Ravi et al. 2004).

TABLE 1—COMPARISON BETWEEN A TYPICAL 15.8-lbm/gal SLURRY AND THE DESIRED SLURRY

Cement Type	Conventional	Steam Cement
Young's modulus, 10^6 psi	2.0	1.2
Cohesion, psi	3132	1500
Ultimate tensile strength, psi	217	217
Expansion, %	0.0	0.25
Poisson's ratio	0.1	0.1

The effects of well operations were evaluated from FEA. The results are shown in **Figs. 11** and **12** where the comparison between conventional and steam cement slurries is made.

Figs. 11 and 12 show the remaining capacity in the cement sheath after a particular well operation. The remaining capacity is the useful capacity (expressed as a percentage of starting capacity) remaining in the material to withstand another well operation. Fig. 12 shows that the optimized cement system has a much higher remaining capacity than the conventional system, and it should help to maintain integrity during cyclic loading. In fact, conventional cement might not stand up to the injection phase before developing radial cracks in the cement sheath.

Results

The optimum cement design was tested in the lab and successfully placed in the annulus. Subsequently, well operations were carried out as planned. The well operations included cementing the casing string, pressure testing before perforating, injecting superheated steam, followed by putting the well on production. On wells where this analysis technique was not applied and the cement slurry was not optimized accordingly, steam breakthrough from the annulus occurred immediately during the steaming cycle, rendering the wells useless. From an economics point of view, the loss of zonal isolation in every well meant a loss of 80 BOPD in addition to the "sunk" well costs. However, on the wells where the enhanced slurry designs were used, no steam breakthrough occurred, even after the steam cycles were repeated. The optimized cement design was able to withstand the well operations and withstand the loads discussed. The bond logs obtained from these wells were also good (**Figs. 13** and **14**).

Finally, one other aspect of the cement slurry design was to shorten the time from completing the well to the onset of steam injection. As mentioned previously, the practice was to wait 30 days between the completion and steam injection point. By optimizing the cement retrogression components in this lightweight slurry design, the interim period was safely reduced to 15 days, maintaining some safety margin for field errors. **Fig. 15** is the compressive-strength chart of the optimized slurry design; it shows a steady compressive-strength value, even after applying steam temperatures to the slurry after 15 days of waiting-on-cement time for stabilization of cement compressive strength.

Conclusions

The following conclusions are a result of this work.

- The optimized steam-stimulation cement designs are effective cement systems that help withstand loads that could occur during the cyclic-steam injection process.
- The steam-cement design was an 11.8-lbm/gal lightweight slurry and able to provide annular fill-up.
- The optimized cement design provided shorter waiting-on-cement time to initiate steam injection.
- The FEA model is a valid procedure for analyzing the cement sheath endurance properties for steam-injection wells.
- The success of achieving zonal isolation with the improved design saved the project from economic failure.

Acknowledgement

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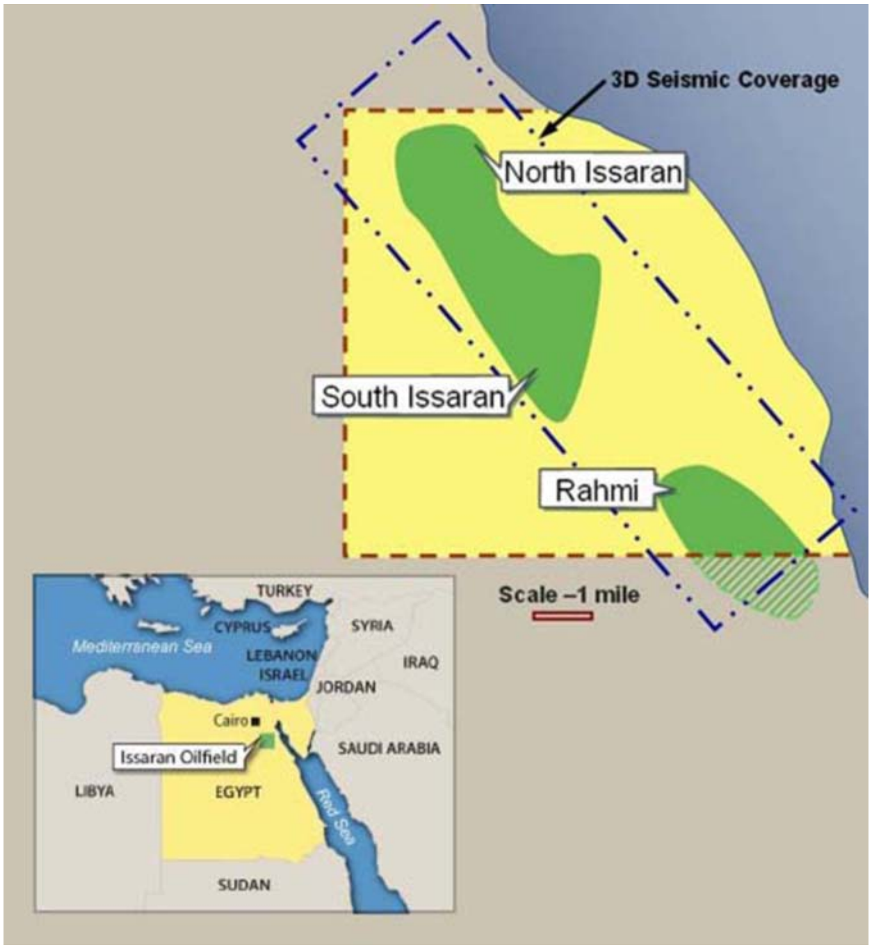

Fig. 1—Issaran field location.

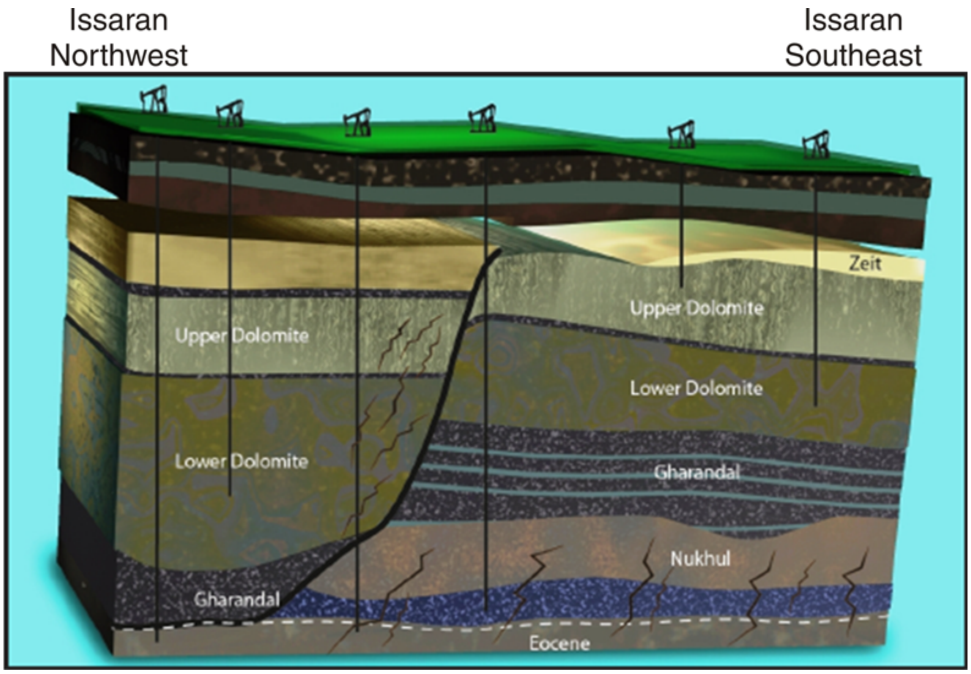

Fig. 2—Issaran field stratigraphy.

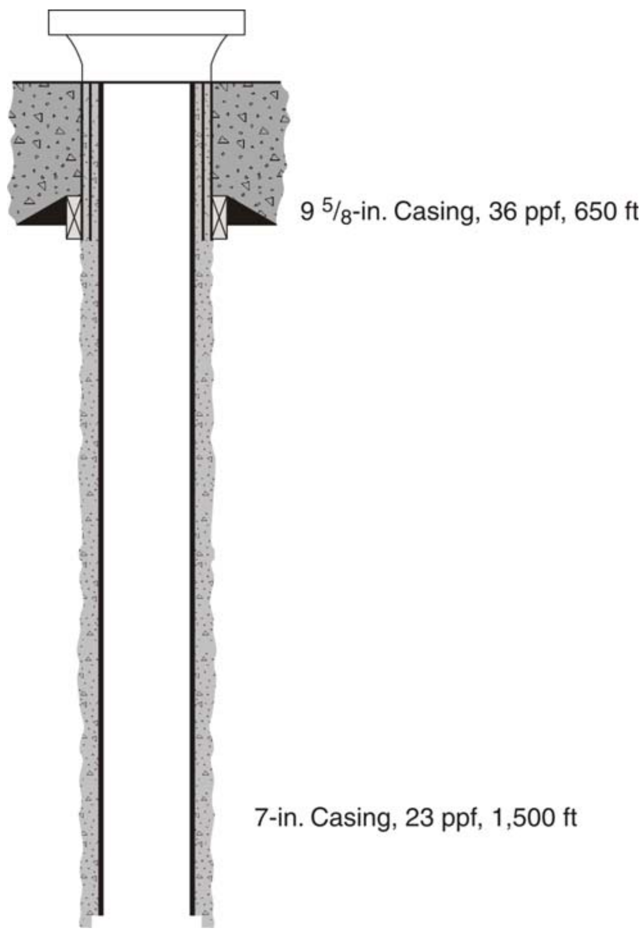

Fig. 3—Well schematic.

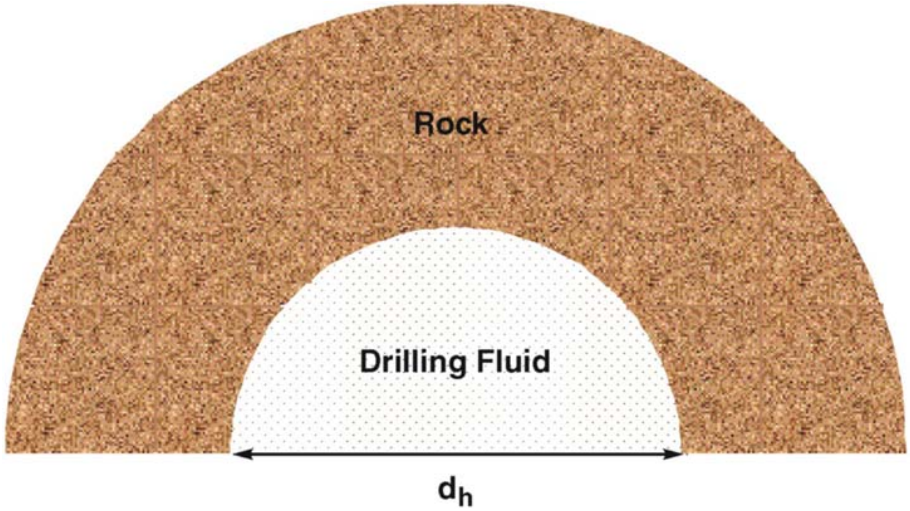

Fig. 4—Drill hole.

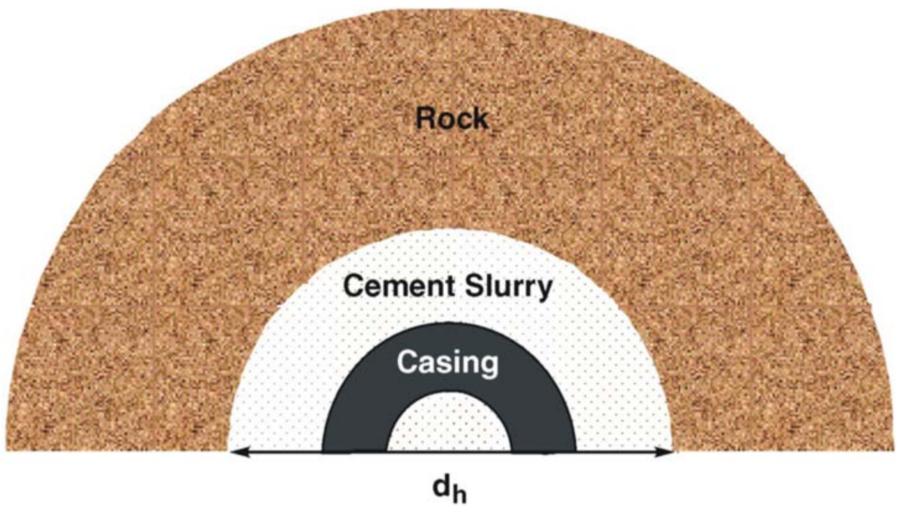

Fig. 5—Run casing and cement slurry.

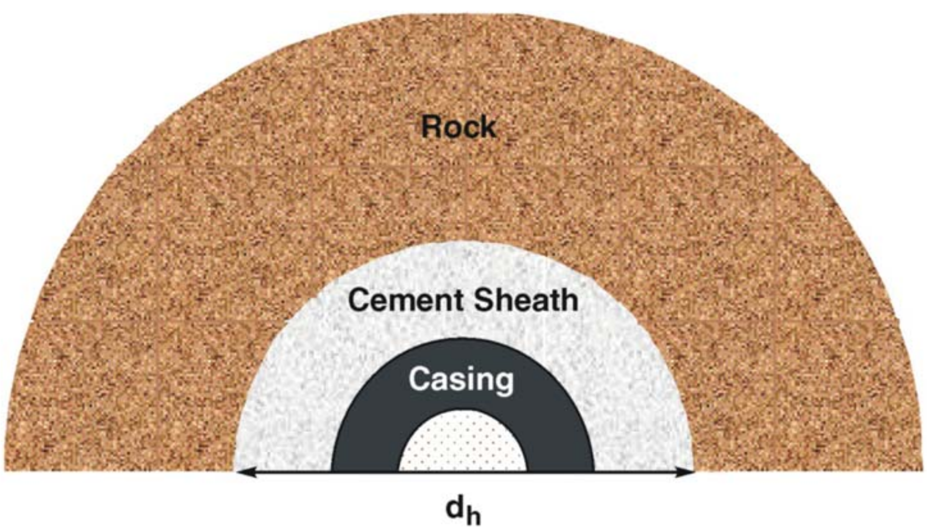

Fig. 6—Cement hydration.

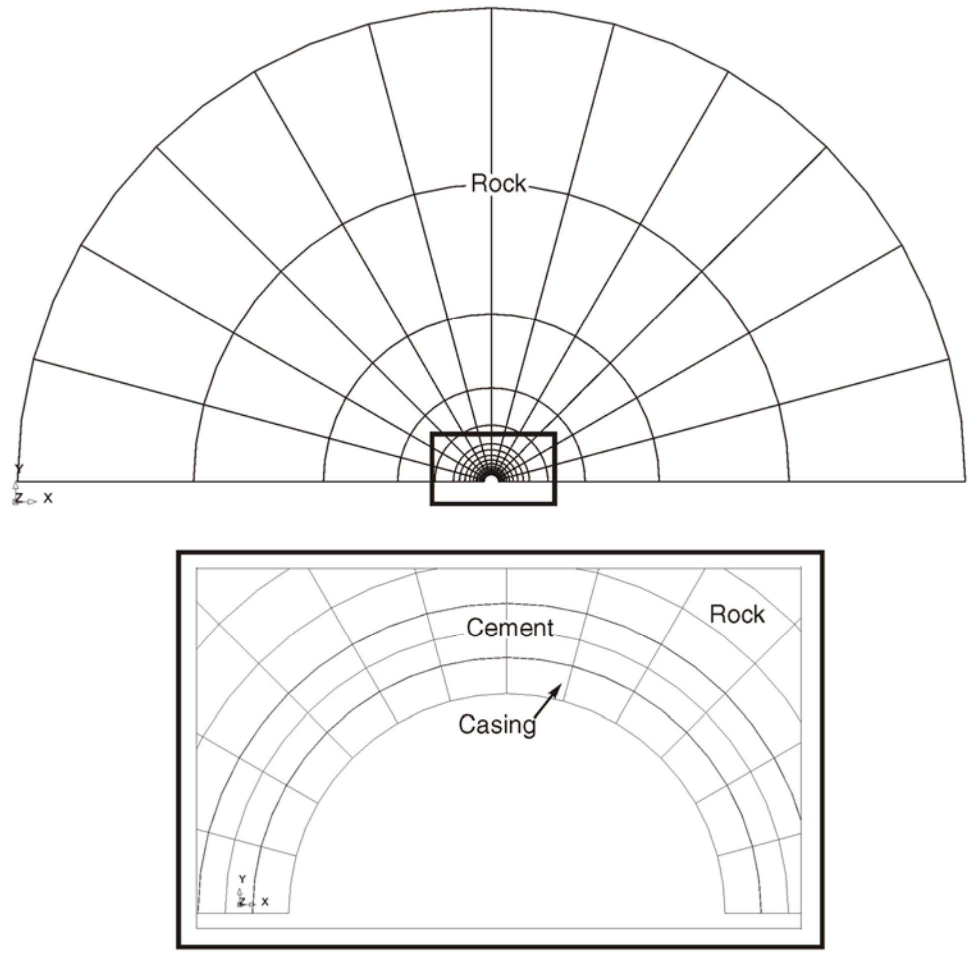

Fig. 7—Finite-element grid.

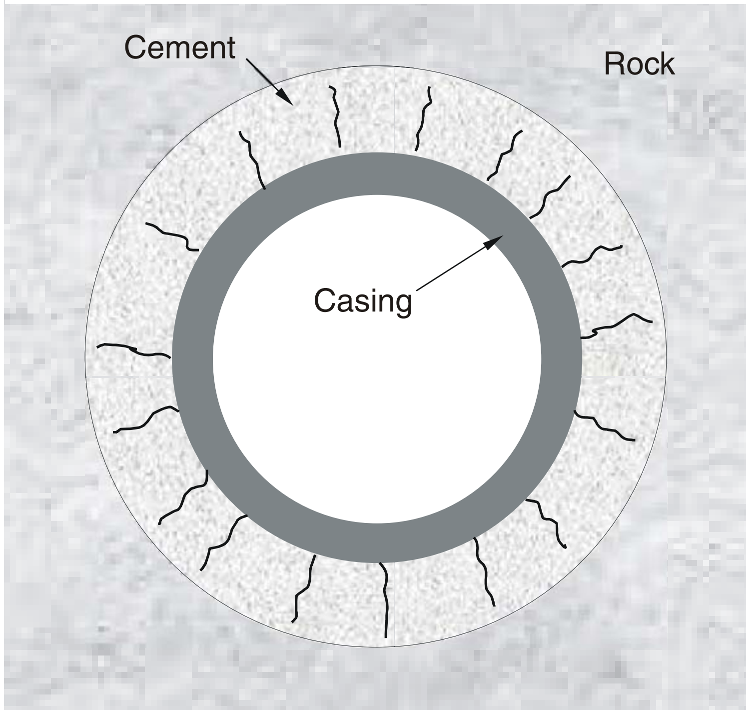

Fig. 8—Radial cracks in the cement sheath.

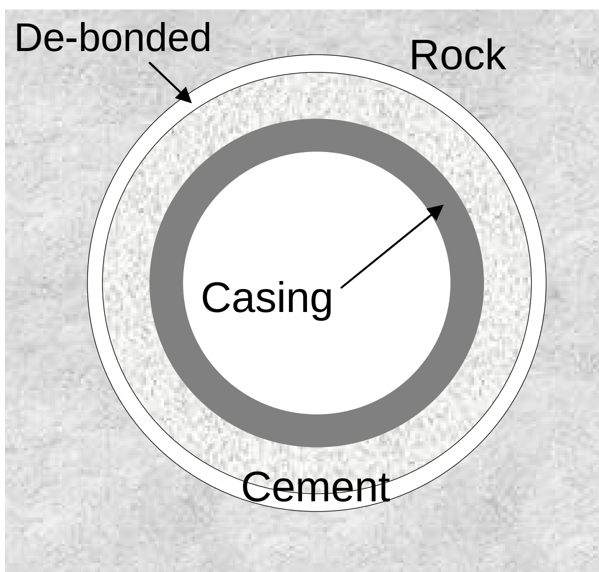

Fig. 9—Debonding between casing and rock.

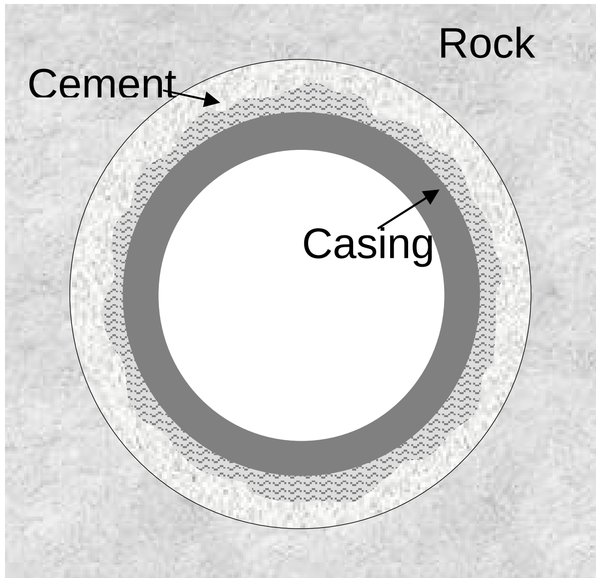

Fig. 10—Deformation.

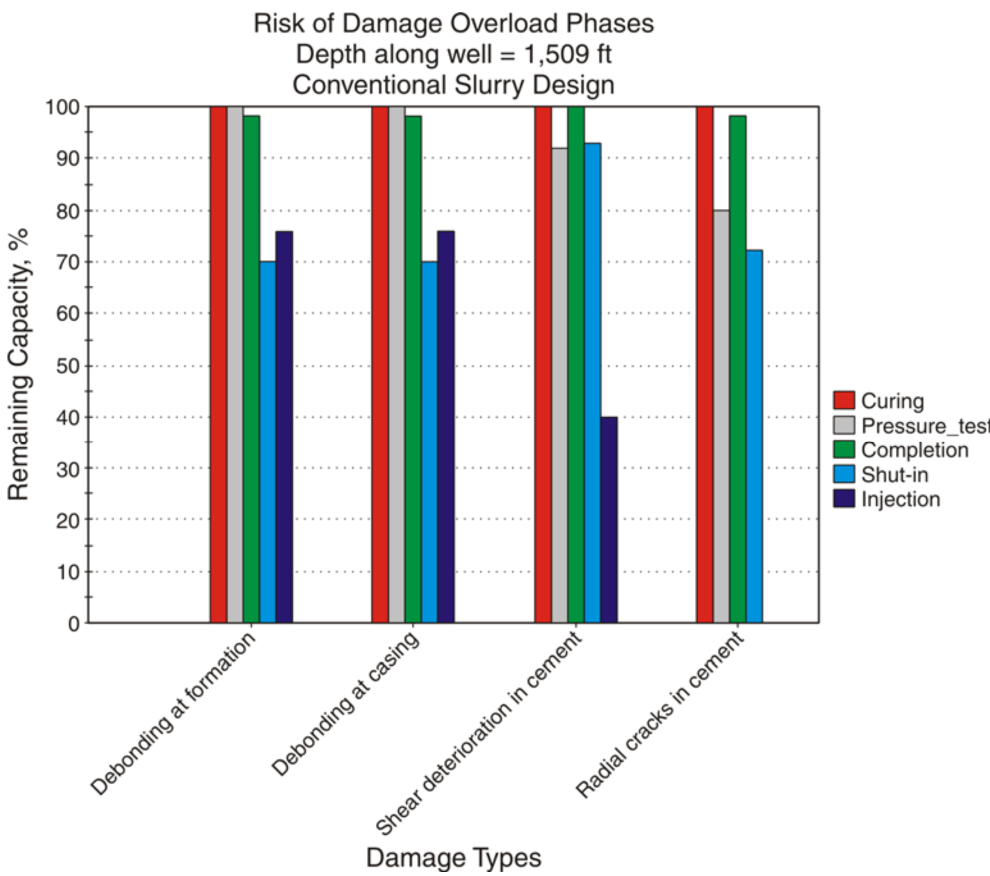

Fig. 11—Remaining capacity in the cement sheath (conventional cement slurry) after well operations at 1,500 ft.

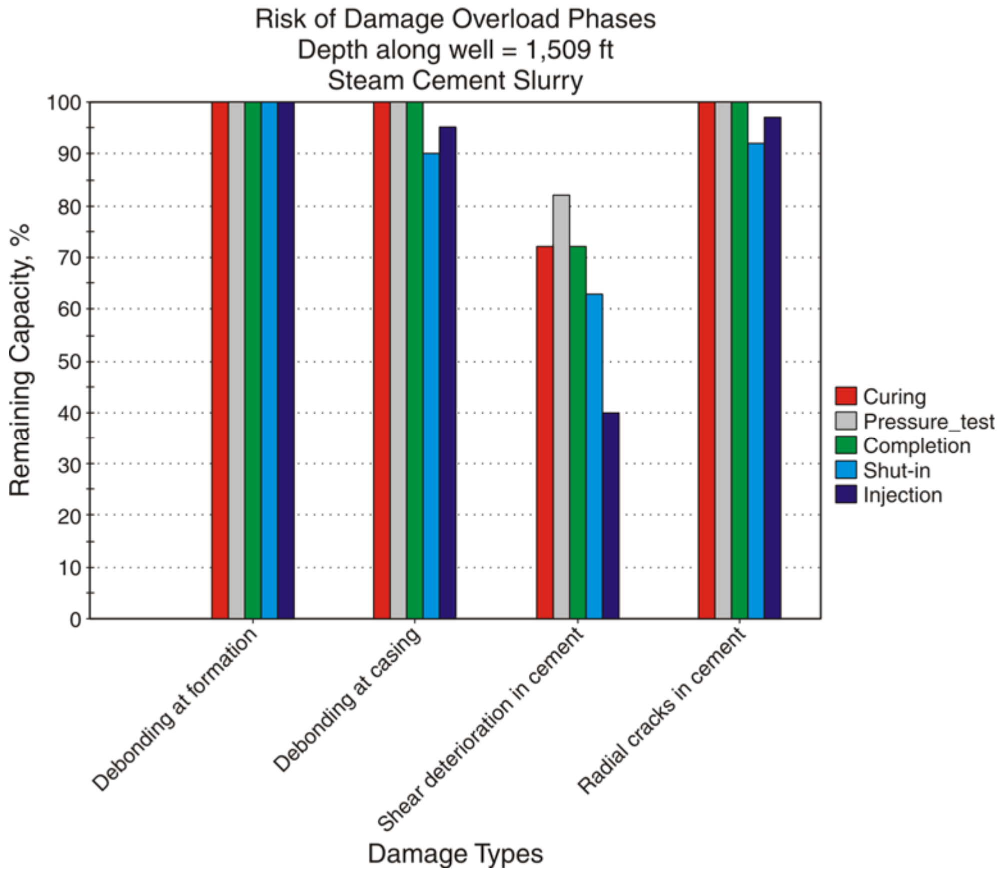

Fig. 12—Remaining capacity in the cement sheath (steam-cement slurry) after well operations at 1,500 ft.

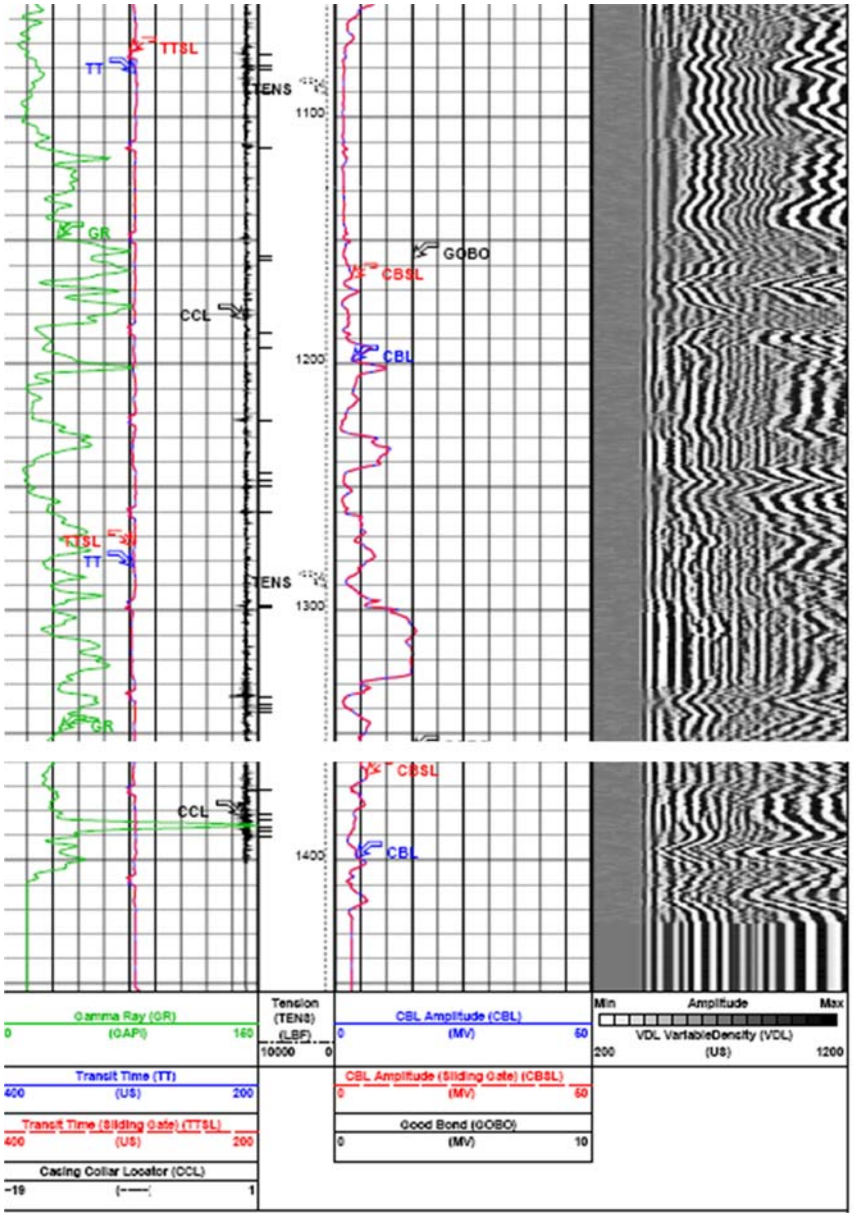

Fig. 13—Cement-bond log from Well ISS-108.

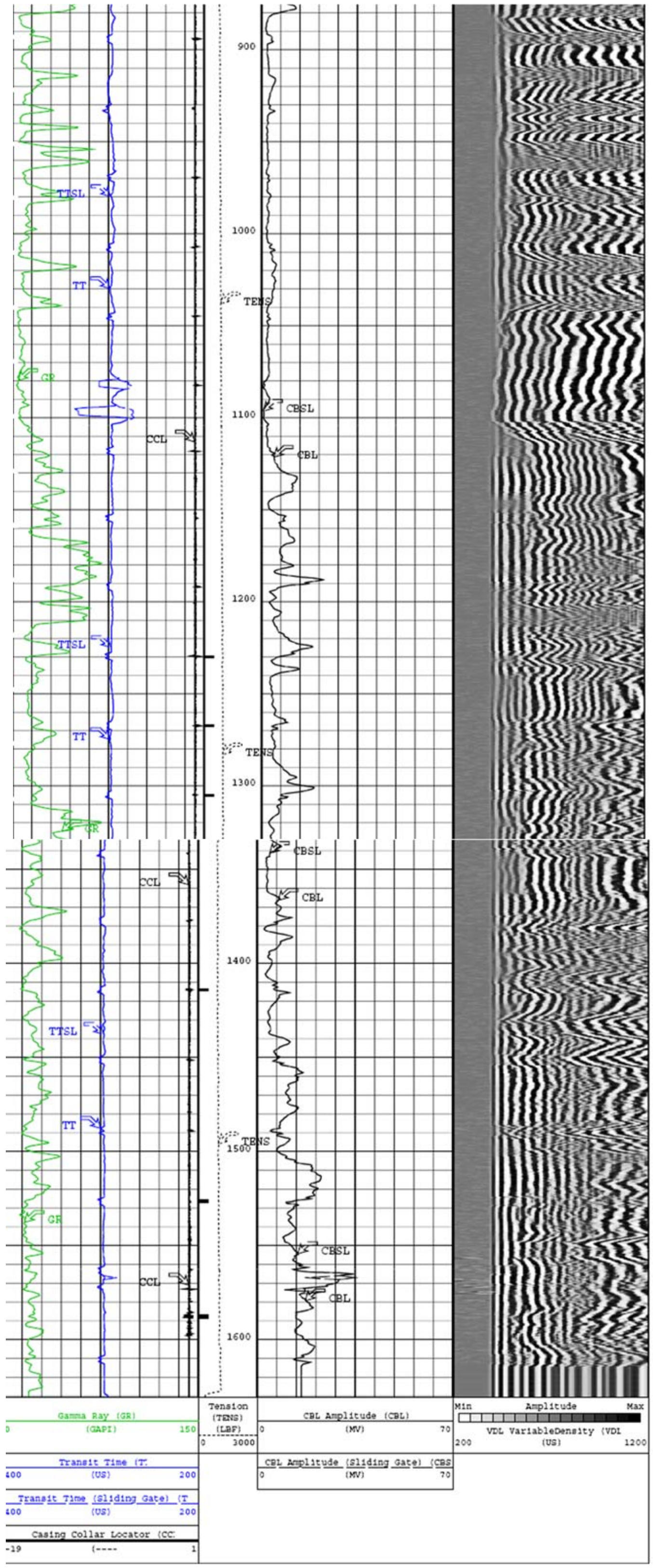

Fig. 14—Cement-bond log from Well CSS-148.

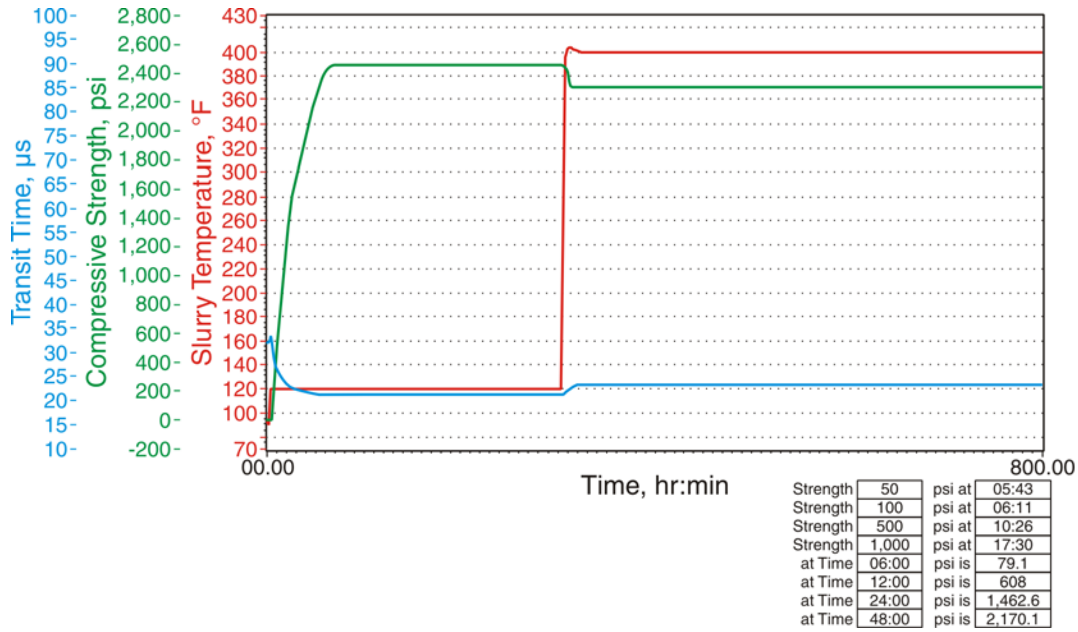

Fig.15—Compressive-strength-development chart.