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January 7, 1993

Coquina Oil Company
1717 St James Place
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Attn: Sherri Clark

Subject - Avalon Delaware Unit

Dear Sherri,

This letter is intended to be a record of the meeting between Yates and Exxon on December 9, 1992, concerning the proposed Avalon Delaware Unit. Exxon replied to our concern about primary reserves on December 22, 1992; and that reply is included here also.

You recall that Yates and Coquina had questions about four areas in the Engineering Report prepared by Exxon. As expressed in my letter of November 25 (Attachment 1) to Larry Long, our questions covered: EX 2A

1) Area Outside Primary Production
2) Primary Reserves
3) Geology and Modeling
4) Workover Reserves

EX 2B

Exxon prepared rather elaborate responses (Attachment 2) to each of the four questions.

Area Outside Primary Production - Gil Beuhler

My main concern is that Exxon may commit about $100 million for CO_2 both inside and outside the area of primary production without decision points to provide an escape mechanism in the remote case that the projects fails early in its life. Exxon attempted to address this concern with the time line on page 3 of Attachment 3. EX 2B Exxon sees the project having two phases. Phase I covers the initiation of waterflooding during 1993 and 1994. An $18 million AFE in late 1992 would cover the drilling of 19 wells (18 injectors and one producer all in the area of primary production) plus installation of water-injection facilities. A separate AFE for $8 million might be issued in 1994 if consolidation of production facilities is necessary after the central waterflood gets underway. Phase II covers the installation of the CO_2 project during the period 1996 to 1998. Exxon plans to send out one AFE in the middle of 1995 to cover the drilling of 56 wells, installation of CO_2 facilities plus a plant to compress CO_2 for recycle. The amount of the AFE is about $77 million for CO2 development both inside and outside the area of primary production. This amount includes about $23 million for a plant to recycle produced CO2. The actual recycle needs are difficult to estimate before the project begins. Initially, Exxon plans to inject all purchased CO2 into the area of primary production. Some water injectors will be needed outside the primary production area at that time to handle water produced inside the primary production area. However, the number of outside injectors required to support CO2 injection inside the primary production area is only 10 to 20 percent of the outside injectors Exxon plans to drill in the 1996 drilling program. Exxon believes that the entire CO2 project must be installed at once to maximize rate of return. Exxon is comfortable enough with the geology and with its CO2 experience to offset any risk of subpar performance.

Yates pointed out that we disagree with the philosophy behind a single AFE in 1995 for $77 million. I believe it is prudent to have one AFE in 1995 for a CO2 project inside the area of primary production and a second AFE two to three years later for expansion of CO2 outside the area of primary production. The Exxon people sounded sympathetic to our proposal, but the Exxon system must require management approval of the whole CO2 project in 1995. I asked whether Exxon's management in Dallas could approve the whole thing at one time while Exxon in Midland sent out a series of AFE's over several years. The Exxon reply was that this might be possible, but Exxon prefers its own approach. I feel the Exxon people at the meeting believe that our suggestion is logical, but someone higher in the company required that they follow the company line. Exxon agreed to consider our suggestion. If Exxon doesn't modify its position, Yates and Coquina can only seek a voting procedure that permits us to vote down an AFE for $77 million in 1995.

Exxon said its economic runs show a 27 percent rate of return for the area of primary production and a 20 percent rate of return outside the area of Primary production. The corresponding Yates values are 25 and 13 respectively.

Geology and Modeling - Dave Cantrell and Mike Goodwin

My letter of November 25 commented about the fact that the computer modeling required reservoir permeability to be increased by a factor of two or more. I hinted that this might cast suspicion on the accuracy of the log analysis. Exxon's answer was that the reservoir permeability had to be increased because the wells are hydraulically fractured. The Exxon geology work gives results that match core data. The modeling via prototype simulation and scale up is a proven technique that Exxon has used in large reservoirs. A three-dimensional reservoir simulation is unreasonable for a reservoir as big as Avalon Delaware.

I feel the Exxon geology and the Exxon modeling is totally adequate. We learned several items I did not know:

1) Exxon is performing shear-wave VSP at Avalon to determine directional permeability.

2) The sonic logs were not corrected for presence of clay since no correction is needed.

3) Separate correlations of permeability as a function of porosity were developed for each Delaware zone.

4) Water-oil ratios were ignored on wells with large fracture treatments because water is surely produced from out-of-zone.

5) Permeabilities in the simulator were derived by correlating core data from nearby wells to the three prototype wells.

6) All vertical - permeability data came from core taken at Yates C #36.

7) All wells outside the area of primary production were assumed to have low GOR's because they are located down - structure.

Decline Curves (Primary Reserves) - Mike Goodwin

Yates made independent estimates of the remaining oil reserves for all wells in the Avalon Delaware pool and compared estimates with the Exxon numbers in the Engineering Report. The Yates and Exxon estimates matched except for four wells (Stonewall EP #5 and EP #8 and Yates C #3 and #4). At the meeting on December 9, Exxon explained how the Engineering Report calculated reserves, but was not able to explain the differences with the Yates values on the spur of the moment. The Exxon letter of December 22 (Attachment 4) EX 2C says that the reserves of Yates Stonewall EP #5 and #8 should be increased by 31.5 MBO while the reserves for Exxon Yates C Federal #3 and #4 should decrease by 71.1 MBO. At the same time, the reserves of the Yates C #36 should increase by 44.5 MBO. The Yates C #36 is the newest well in the field and occupies the same spacing unit as Yates C #4.

The Engineering Report divided the wells into two groups for reserve purposes: 1) those with no restrictions on rate or GOR and 2) those where GOR and/or oil allowable restricted production. For the first group, Exxon plotted both log of rate versus time and rate versus oil cumulative. Exxon removed extraneous points and fit lines to the remaining data. An average of the two estimates (weighted according to the statistical error bars) was used as ultimate reserves. Yates C Federal #4 fit into this first group, and some confusion related to the spacing unit shared with Yates C #36 caused the apparent error in its reserves. The second group of wells with restricted production could not be analyzed in so straight-forward a manner. Stonewall EP #5 and #8 plus Yates C #3 and #36 all fall into the second group. The Engineering Report used at least two approaches to the restricted wells. In some cases, rate versus cumulative could be plotted over some intervals where the well did produce at capacity. In other cases, GOR was plotted against oil cumulative on semilog paper up to a limiting GOR of 20,000. Exxon agreed that 20,000 is probably low as a limiting GOR for EP #5 and EP #8; and the reserves have been raised accordingly. Yates C #36 is a special case where the well has produced for a short time at rates above allowable. Initially, Exxon made a conservative estimate of reserves for Yates C #36. The letter of December 22 includes a less conservative estimate for Yates C #36.

One thing that is clear to me is that Exxon's goal has always been to provide an unbiased estimate of reserves. Yates questioned wells where reserves are difficult to estimate.

Workover Reserves - Dave Cantrell, Mike Goodwin

Exxon explained that the Yates work at re-completing Stonewall EP #7 actually fits Exxon's expectation for workover so that the workover reserves should be retained in the Engineering Report.

Yates tested three Delaware zones in the EP #7 and ended up producing 13 BO and 117 BW from the zone at 2558-2572. Exxon contends that its experience shows that oil-on-swab translates into a successful completion after frac while "no show" on swab still means a successful completion after frac in 50 percent of the cases. Also Exxon developed a correlation (Attachment 3, page 73) between feet of hydrocarbon pore volume and production after frac. About 2 feet of hydrocarbon pore volume is required for a minimal completion while 6 to 11 feet is required for production above 100 BOPD. Now apply the Exxon experience to Stonewall EP #7. The zone at 2796-2836 has 3.86 feet of hydrocarbon pore volume. Yates swabbed a small show of gas after acid and abandoned the zone. Exxon believes this is the best zone in the well and it might produce 40 BOPD. The zone at 2662-2686 has 2.50 feet of hydrocarbon pore volume. Yates swabbed the well dry after acid and abandoned the zone. Exxon thinks this zone could produce 25 BOPD. The zone at 2558-2572 has 1.92 feet of hydrocarbon pore volume. Yates swabbed about 1.5 BO in two days and fraced the zone. After swabbing back most of the frac load, Yates produced 13 BO and 117 BW on initial potential. The Exxon correlation says the initial rate should be 11 BOPD.

The Exxon conclusion is that Exxon understands Delaware workovers and Stonewall EP #7 behaved according to the Exxon model. After unitization, Exxon will frac the two lower zones and increase production by 65 BOPD. Since the assumed workover reserves benefit Yates, we are willing to believe the Exxon explanation and leave the workover reserves in the Engineering Report.

SUMMARY

I feel the Exxon responses concerning Workover Reserves and Geology/Modeling are completely acceptable. Exxon essentially agrees with the Yates modifications to Primary Reserves. The Exxon approach to the Area Outside Primary Production still seems crazy to me. The Exxon letter of December 22 repeats Exxon's offer to add a paragraph to the report which says that the economics in the report assume the entire CO2 flood will be implemented as one continuous project, but the risk associated with the area outside primary production may cause some delay in expanding CO2 to the outer ring. Such a delay will have some minor negative effect on the overall economics. So, the questions come down to whether we should accept the Exxon Engineering Report with such an addendum and whether the addendum should include anything about the revised primary reserves. I suggest an addendum with a bit of CO_2 philosophy plus a list of revised primary reserves for five wells. What think you?

We owe Exxon a reply on the Engineering Report. Let's talk a few days after you receive this.

Sincerely,

Dave Boneau

David F. Boneau
Reservoir Engineering Supervisor

DFB/mjw

Attachments

cc Larry Long (Exxon)
Mike Slater
Brian Collins
Bob Fant
Randy Patterson
Brent May