Innovative Use of the Oil and Gas Regulations

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Abstract

Applications to amend existing schemes for enhanced recovery of oil by water injection to allow for the intermittent reinjection of raw sour solution gas into the Bashaw D-2G and D-2L pools during times of shutdown was a low cost solution that would allow continuous production while conserving the sour gas. The applications were approved, and the operator is now able to produce oil and gas continuously despite disruptions, planned or unplanned, of the downstream processing or transportation facilities.

Introduction

Due to third party failures or scheduled and unscheduled maintenance of downstream operations, KeyWest Resources Ltd. were forced to completely shut-in their oil and gas production in the Bashaw D-2G and D-2L pools (Figures 1 and 2) for a significant number of days each year. This represented a loss in revenue of approximately $81,000 per day (gross 2002 dollars based on Cdn $40/barrel oil and Cdn$4/MSCF gas). KeyWest was anxious to find a solution that would work within the existing regulatory framework and that would eliminate the pool shut-ins due to third party failures. KeyWest also required that the solution result in little or no capital expenditure. The application would have to address the EUB’s three main concerns: conservation (of the oil), equity and economics.

Applications submitted to the EUB, pursuant to the requirements laid out in Guide 65: Resources Applications for Conventional Oil and Gas Reservoirs, June 2000(1), Sections 2.1 and 4.1, requested the following:

1. Amend Approvals 7609 and 7274 for the injection of water to enhance oil recovery from the Bashaw D-2L and D-2G pools, respectively, pursuant to Section 26 (1,a) of the Oil and Gas Conservation Act and Guide G-51, by the intermittent reinjection of raw sour solution gas produced from the pool; and to

2. Re-classify the wells approved for Class II water injection in Approvals 7609 and 7274 to Class III injection (sour gas) wells.

The EUB reviewed the initial submission and compiled a list of concerns relating to the suitability and capability of the existing water injection pipeline network to handle the sour gas and the effect of the proposed reinjection on overall oil recovery in the Bashaw D-2L and D-2G pools.

The initial and supplemental submissions met all the requirements of Guide 65, while meeting KeyWest’s requirement to maintain production during times of shut-in. KeyWest was required to compromise on the annual volume they would reinject. The volume approved was a volume that reflected current gas production rates for three consecutive months, rather than a rate based on future development and a catastrophic six month shut-in. Approval to reinject sour gas intermittently into the Bashaw D-2L and D-2G pools, during times when the pools would be shut-in due to third party failures, were granted March 28, 2003 and December 23, 2003, respectively.

Discussion

Applications #1287609 and #1287472 were submitted to the Alberta Energy and Utilities Board by Fekete Associates, Inc. on behalf of KeyWest Energy Corporation in December 2002. The purpose of the applications was solely to avoid the loss of production due to plant or pipeline failures, routine maintenance or scheduled turnarounds. The sour well effluent from the pools is transported on KeyWest’s sour oil well effluent pipeline to KeyWest’s Bashaw Oil Handling and Waterflood Facility at 02-09-41-23W4. The majority of the water is removed and reinjected at this facility. The oil, gas and remaining water are shipped on the KeyWest-operated South Bashaw Emulsion Pipeline to the treating facility at Clive 04-15-40-24W4. The remaining water is removed and disposed of, the oil enters a sales pipeline and the gas is broken out and sent to Duke’s Nevis Sour Gas Processing Facility at 16-33-38-22W4. If any of these downstream components fail or becomes incapable of handling the well effluent, KeyWest has two choices: shut-in all the current production from the Bashaw D-2L and D-2G pools (approximately 295 m$^3$/day of oil) or flare approximately 45 $10^6$m$^3$/d (December 2002 rate) of raw sour gas.

KeyWest did not consider shutting in 295 $m^3$/day of oil production a practical or economic solution, nor did it consider flaring 45 $10^6$m$^3$/d of raw sour gas to be judicious. They saw the reinjection of the raw sour solution gas as an environmentally responsible and safe alternative to flaring.

The proposed raw sour solution gas reinjection would occur in the existing injection wells that were already approved as water injection wells under Approvals 7609 and 7274. The wells were injecting sour produced water into the Bashaw D-2L and D-2G pools to provide pressure maintenance. Waterflooding, for the purpose of enhanced oil recovery, has been approved in the Bashaw D-2L and D-2G pools since 1994 and 1993, respectively.

Under the proposed scheme, the raw sour solution gas would be reinjected concurrently with the sour water at KeyWest’s Bashaw Oil Handling and Waterflood Facility located at 02-09-41-23W4, into the seven approved injectors on a pro-rated basis. Each injector would reinject the volume of gas that was produced from the offsetting supported producers to insure the approved injection pressure would not be exceeded in any one injection well and to
insure the re-introduction of gas into the reservoir would not create any local imbalances in voidage or composition.

The proposed raw sour gas reinjection volume was approximately 95 $10^3$ m$^3$/d of gas. As of December 2002, the wells were reinjecting approximately 900 m$^3$/day of sour water through three injectors into the D-2L pool and 1,430 m$^3$/day of sour water through four injectors into the D-2G pool. Furthermore, since Key-West was not increasing the concentration of the sour components in the system, no change to the piping or injection system or to the Emergency Response Plan was required.

The maximum anticipated gas liquid ratio in the proposed D-2L scheme is approximately 35 m$^3$/m$^3$ and the maximum anticipated gas liquid ratio in the proposed D-2G scheme is approximately 55 m$^3$/m$^3$. The maximum anticipated wellhead injection pressure is 10,000 kPa. There would be no risk of fracturing the D-2 formation with the proposed sour gas reinjection.

The raw gas contains 8.9% nitrogen, 3.5% carbon dioxide and 12.3% hydrogen sulfide.

The Bashaw D-2L pool was discovered in 1992 with the drilling of Well 08-02-41-23W4. As of December 2002, there were eight oil wells, three water injection wells, four abandoned oil wells and one suspended oil well in the Bashaw D-2L pool. As of that date, 653 $10^3$ m$^3$ of oil, 97 $10^6$ m$^3$ of gas and 1,112 $10^3$ m$^3$ of water had been produced from the Bashaw D-2L pool and 2,006 $10^3$ m$^3$ of water had been reinjected into the Bashaw D-2L pool. The Bashaw D-2L pool has a holding with a 200 m interwell distance and a 100 m buffer for the entire D-2L pool, and has been approved for Good Production Practice (GPP) since December 1998.
The Bashaw D-2G pool was discovered in 1989 with the drilling of Well 14-12-41-23W4. As of December 2002, there were fifteen oil wells, four water injection wells, four abandoned oil wells and one suspended oil well in the Bashaw D-2G pool. As of that date, 1,339 10^3 m^3 of oil, 274 10^6 m^3 of gas and 1,170 10^3 m^3 of water have been produced from the Bashaw D-2G pool and 3,960 10^3 m^3 of water has been reinjected into the Bashaw D-2G pool. The Bashaw D-2G pool is on two legal subdivisions and quarter Section spacing with well density further increased by a holding on the entire D-2G pool. The Bashaw D-2G pool has been approved for GPP since December 2000.

The proposed injection wells are currently approved for Class II disposal. Re-classifying the injection wells to Class III was required to facilitate the reinjection of raw sour gas in the Bashaw D-2L and D-2G pools since the composition of the injectant would change under the proposed scheme.

**Geology**

The Bashaw D-2L and D-2G pools consist of an elongated dolomitized shoal trending NW to SE. Localized biohermal buildups along this shoal yield intervals of greater porosity and permeability due to the vuggy nature of these bioherms. The trapping mechanism for oil and gas is an anhydritic dolostone surrounding and overlaying the reservoir. The tight Ireton Formation below is typically 5-10 m thick and precludes pressure communication with the underlying water-bearing Leduc Formation. The entire reservoir dips to the northwest, and thus has a gas cap overlying the
oil pay in the southern half. The gas/oil contact is established at -877.9 mSS.

Conservation

Conservation would not be adversely affected by the proposed reinjection of raw sour gas. The cumulative voidage replacement ratio in the D-2G pool was 1.05 as of December 2002. The waterflood has been very effective, recovering 39.5% of the initial oil-in-place by that date. The D-2G pool had been re-pressured to an average reservoir pressure of approximately 15,000 kPa and theGOR had steadily declined from a maximum of approximately 650 m³/m³ in early 1993, to approximately 198 m³/m³ in September 2002.

In the Bashaw D-2L pool, the cumulative voidage replacement ratio is 0.95 as of December 2002. Similarly, the waterflood has been very effective, recovering 54% of the initial oil-in-place by that date. The D-2G pool had been re-pressured to an average reservoir pressure of approximately 15,000 kPa and theGOR had steadily declined from a maximum of approximately 150 m³/m³ in 1993-1994, to approximately 120 m³/m³ in September 2002.

Under the existing depletion strategy, gas is conserved. In the proposed gas reinjection scheme, produced gas would continue to be conserved. The gas would be reinjected into the formation and produced at a later time.

The requested maximum annual volume of gas to be reinjected would be negligible (approximately 2%) relative to the total hydrocarbon reservoir volume. The voidage replacement ratio would be maintained. Therefore, the reinjection of raw sour gas into the Bashaw D-2L and D-2G pools would have no effect on conservation and the recovery of oil.

The requested maximum annual reinjection was based on a catastrophic, worst case scenario where KeyWest would be forced to reinject up to 6 months of raw sour gas production from the Bashaw D-2L and D-2G pools. Production and revenue streams to the pool owners and the Province would be uninterrupted under the proposed reinjection scheme.

Equity

Notification in accordance with Guide 65 requirements to off-setting well licensees and working interest owners was conducted. Given the extent of development in the pools, the inconvenience and economic losses caused by interruptions in production and the overall benefit to all pool participants, no objections were anticipated and none were received.

Economics

There were no arguments on the basis of economics as the proposed sour gas reinjection did not propose a change in the depletion strategy or a change in the overall recovery of oil. The economics centred on the loss of revenue to KeyWest during shut-ins. It was estimated that revenue losses could be as much as $81,000 per day (gross 2002 dollars), if all production from both pools was curtailed. During these shut-ins, the waterflood was also shut-in. Shutting down and restarting the production and waterflood after an extended period of inactivity is costly and may be detrimental to conservation. However, the possible effects on conservation and economics of re-starting the production and waterflood were not examined in the EUB submission.

Conclusion

The proposed volume of gas to be reinjected would occupy a small volume in the reservoir and have a negligible effect on the overall performance of the waterflood. The proposed raw sour gas reinjection would have no negative impact on the recovery of oil in the existing waterflood.

The requested amendments to Approvals 7609 and 7274 offer an innovative and economic alternative to flaring or shutting-in production in the Bashaw D-2L and D-2G pools in the event of infrastructure failures and scheduled maintenance. Intermittent reinjection of raw sour solution gas is intended to be a contingency measure that would provide an economic, environmentally responsible and safe alternative to flaring in the Bashaw D-2L and D-2G pools. Approval of the requested amendment to Approvals 7609 and 7274 would enable continued economic development of the Bashaw D-2L and D-2G oil production and waterflood in the area, and would contribute to overall hydrocarbon recovery in the Bashaw D-2 formation. The applications were made under the existing regulations and required no extraordinary data to satisfy the requirements laid out in the Guide 65 Resources Applications.

The EUB reviewed the initial submission dated December 20, 2002, compiled a list of concerns in letters dated January 30, 2003 and provided clarification and guidance throughout the submission and review process, as required. The supplemental submission was sent to the EUB February 25, 2003. The data were readily available for the initial and supplemental submissions from either public sources or from KeyWest.

Approvals to reinject sour gas intermittently into the D-2L and D-2G pools, during times when the pools would be shut-in due to third party failures, were granted March 28, 2003 and December 23, 2003, respectively. The volumes approved were volumes that reflected the current gas production rate and a catastrophic three month shut-in.

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Conversion of Units

1 Barrel (Petroleum)(bbl) = 0.1589873 cubic metre (m³)
1 Cubic Foot (ft³) = 0.0283168 cubic metre (m³)

REFERENCES


Author’s Biography

Robyn Swanson is a graduate of Petroleum Engineering Technology at the Southern Alberta Institute of Technology (SAIT), Calgary, AB, and petroleum engineering at Tulsa University in Tulsa, Oklahoma. Robyn has worked in the public sector teaching at the Northern Alberta Institute of Technology (NAIT), Edmonton, AB, and in the private sector in field and head offices for Amoco Canada Ltd., Anderson Exploration and Fekete Associates, Inc., where she is currently employed and managing the regulatory group.