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Unsuccessful hydraulic fracturing cases in Australia: Investigation into causes of failures and their remedies

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Abstract

This paper presents the results of investigations into two field cases in Australia where expensive fracture treatments did not yield expected benefits. Field_1 contains a thin gas reservoir in which more than 20 vertical wells were drilled and hydraulically fractured. The post-frac well tests yielded low production rates prompting to a comprehensive study. Among other reservoir properties, the in-situ stresses were characterized and found to be in the reverse faulting stress regime. Through 3D mixed-mode simulation of hydraulic fracture propagation, the first part of this paper shows that the vertical fracture initiated from the vertical wellbore would turn and twist to be horizontal during propagation and would require extremely high treatment pressure and leave very little conduit for flow. These were the main reasons for multiple screen-outs during treatments and post-frac low production rates from the reservoir. A number of potentially effective hydraulic fracture treatments have been recommended for the reservoir.

Field_2 contains a tight-gas reservoir, which a number of operators have attempted to develop by hydraulic fracturing over the last 30 years. After every attempt, the post-frac flow rate was lower than the pre-frac rate and therefore the well was plugged and abandoned. The second part of this paper presents the results of a comprehensive investigation into the field. The investigation has established the inadequacy of the treatment carried out in the reservoir to achieve the expected production rate, and demonstrated how more effective treatments could be designed by using a constrained hydraulic fracturing optimization model.

Keywords: Reservoir stimulation; Hydraulic fracturing; Fracture treatment; Geomechanics; In-situ stresses; Fracturing tight-gas reservoir

1. Introduction

Hydraulic fracturing is a widely used technology in the petroleum industry to increase production rates from low-permeability reservoirs. It is a process whereby proppant-laden fluid is injected into a well under high pressure to initiate a fracture from the wellbore wall and extend the fracture towards the reservoir boundary. Once the injection is ceased, the propped fracture becomes the principal conduit for flow of the hydrocarbon from the reservoir to the well, and thus allowing enhanced production. The petroleum industry has long been applying hydraulic fracturing treatment as a principal technique to improve oil and gas production. Of the production wells drilled in North America since 1950s, about 70% of gas wells and 50% of oil wells have been hydraulically fractured (Valko and Economides, 1995). Numerous attempts for hydraulic fracturing have been made in Australia as well, particularly to develop tight-gas reservoirs. Improved design and

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execution of hydraulic fracturing treatments is, therefore, an important task in the petroleum industry.

Despite some success cases, the operational performance and cost-benefit accounts of hydraulic fracture treatments have not been positive in many occasions worldwide, particularly onshore Australia (Rahman et al., 2000). Major difficulties encountered during treatments include the requirement of high injection pressure, high frictional pressure drop, inability to inject proppant at required concentrations within the pump capacity, inability to extend the initiated fracture, and consequently, poor post-stimulation productivity. Further improved understanding is, therefore, necessary to design and execute treatments that would be effective for such unconventional field conditions. Without field-appropriate design and execution of treatments, there is very little chance that fracturing programs will be successful to realize its potential benefits commensurate to its investments and expectations. This paper presents two such field cases in Australia where fracture treatments were unsuccessful. The objective of this paper is to investigate the causes for failures of the treatments carried out in the two representative cases and to suggest measures that could be taken to increase the likelihood of success. Because of the confidentiality agreements with companies, the fields, the operators, the service companies and any products associated with the actual treatments will be represented by hypothetical or generic names in this paper.

Field_1 is owned by Operator_1 and it contains a Methane gas reservoir with a shallow thickness and hydraulic fracture treatments were carried out to increase gas production from the reservoir. Without much reservoir characterization, Service_Co_1 was contracted to carry out fracture treatments, more than 20 wells were fractured with great enthusiasm on both sides. Fig. 1 shows a typical

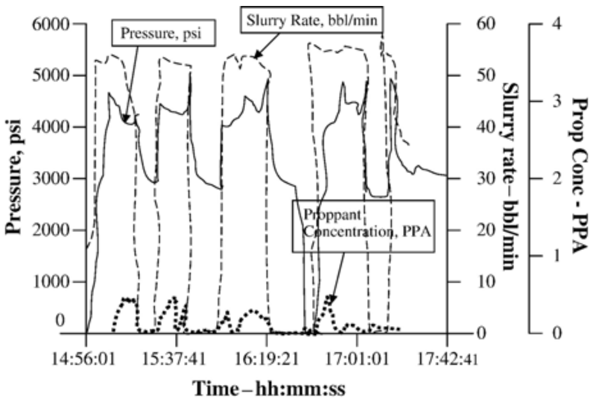

Fig. 1. Typical injection time versus pressure history during fracturing in Field_1.

fracture treatment history in the field. The post-frac well production did not go nowhere near to the expected/predicted rate. This prompted to undertake a comprehensive study from the drilling phase, to reservoir characterization, geomechanics modeling and finally fracture treatment design.

Field_2 contains a large tight-gas reservoir holding 3.7 trillion cubic feet of gas in-place at 280 km away from a major city in Australia. Over a period of 30 years, four wells have been drilled and hydraulically fractured by 4 different operators. Every time, the hydraulic fracture treatment led to a lower production rate than the pre-frac rate. Operator_2 recently undertook a remedial treatment in Well_4. This treatment doubled the production rate but was still uneconomic.

This paper will elaborate both cases further and investigate causes for failure based on fundamental principles of hydraulic fracturing, and finally recommend a series of measures to maximize the likelihood of success.

2. Investigation into Field_1

Experimental and associated computational studies were carried out to characterize the following mechanical and petrophysical properties of the reservoir formation: (a) bulk matrix porosity, (b) matrix permeability, (c) surface chemistry of gas/water systems, (d) relative permeability in water/gas systems, (e) core flooding tests with fresh water, linear gel and cross-linked fracturing fluids, (f) mechanical properties of reservoir rocks, and (g) in-situ stresses in the reservoir.

Core samples from two wells at a reasonable distance were taken for the study. For one well, the pay zone was at 2200 ft depth, whereas this depth was 2000 ft for the other well. Four samples were prepared and tested from each of the wells. The average porosity was found to be 1.65% for one well and 2.75% for the other well. This represents very low porosity of the formation and its significant spatial variation.

The matrix permeability of core samples to gas was measured for the two wells at different confining pressures and was also estimated through history matching by reservoir simulation. An average representative value of 2.5 mD was accepted for analysis from a wide range of variation due to confining pressures and spatial locations.

To evaluate the cleaning quality of various fracturing fluids, the surface chemistry behavior was investigated by laboratory measurement of changes in interfacial tension and contact angle of linear gel and cross linked gel fracturing fluid systems. The surface tension was found to have a tendency to decrease after gel fluids