PLAINS CO_2 REDUCTION (PCOR) PARTNERSHIP (PHASE II) –ZAMA FIELD VALIDATION TEST REGIONAL TECHNOLOGY IMPLEMENTATION PLAN

Task 3 – Deliverable D52

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EXECUTIVE SUMMARY

A comprehensive, monitoring, verification, and accounting (MVA) plan is critical to the success of any geological carbon sequestration project utilized as a method of reducing carbon dioxide (CO_2) emissions to the atmosphere. From October 2005 through September 2009, the Zama oil field in northwestern Alberta, Canada, has been the site of acid gas (approximately 70% CO_2 and 30% hydrogen sulphide [H_2S]) injection for the simultaneous purpose of enhanced oil recovery (EOR), H_2S disposal, and sequestration of CO_2. The Plains CO_2 Reduction (PCOR) Partnership has conducted MVA activities at the site throughout this period, while Apache Canada Ltd. has undertaken the injection and hydrocarbon recovery processes. This project has been conducted as part of the U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL) Regional Carbon Sequestration Partnership Program and has been recognized by the Carbon Sequestration Leadership Forum as being uniquely able to fill technological gaps with regard to geological storage of CO_2.

One of the primary purposes of the PCOR Partnership Phase II Program is to develop a Regional Technology Implementation Plan (RTIP) based on the experiences and results generated at Zama. The purpose of the RTIP is to provide technical guidance on approaches for conducting baseline surveys, MVA, and assessing the overall success of injecting CO_2-rich acid gas into deep carbonate oil reservoirs for the purpose of simultaneous CO_2 storage and EOR. The RTIP presents a series of key observations, insights, and recommendations, based on the experiences at Zama, that are intended to be broadly applicable to the injection of acid gas for simultaneous CO_2 storage and EOR operations at locations throughout the United States, Canada, and even the world.

Acid gas has been obtained as a by-product of oil production in the Zama Field and subsequent fluid separation process at the on-site facilities. During the separation process, oil and gas are sent to market while acid gas is redirected back to the field for utilization in EOR operations. Previously, CO_2 was vented to the atmosphere and sulfur was separated from the H_2S and stockpiled in solid form on-site. This project has enabled the simultaneous beneficial use of each of these processing by-products and effective mitigation of two environmental concerns.

The Zama project has been designed to address the issue of monitoring CO_2 sequestration at EOR sites, in this case utilizing H_2S-rich acid gas as the sweep mechanism, in a cost-effective and reliable manner. The primary issues that were addressed include 1) determination of CO_2 and/or H_2S leakage, or lack thereof, from the pinnacle; 2) development of reliable predictions regarding the long-term fate of injected acid gas; and 3) generation of data sets that will support the development and monetization of carbon credits associated with the geologic sequestration of CO_2 at the Zama oil field.

To address these issues, a variety of research activities have been conducted at multiple scales of investigation in an effort to fully understand the ultimate fate of the injected gas. Geological, geomechanical, geochemical, and engineering work has been used to fully describe the injection zone and adjacent strata in an effort to predict the long-term storage potential of this site. Through these activities, confidence in the ability of the Zama oil field to provide long-term containment of injected gas has been achieved. While this project has been focused on one of the hundreds of pinnacles that exist in the Zama Field, many of the results obtained can be applied not only to additional pinnacles in the Alberta Basin, but to similar structures throughout the world.

Monitoring the site has been achieved primarily through fluid sampling and pressure monitoring in both the target pinnacle reef and overlying strata. A gas-phase perfluorocarbon tracer, designed to mimic the injected gas, has been used in an effort to identify any leakage into overlying stratigraphic horizons. Pressure is also being measured at the injection zone and overlying productive zones to ensure 1) overpressurization of the target is not occurring and causing undue stress on the overlying cap rock that could potentially lead to failure and 2) leakage along wellbore pathways is not occurring. Certifying the integrity of the system has been a critical focus area, with tests being completed on the cap rock and injection zone to determine the nature of potential geochemical and geomechanical changes that may occur as a result of acid gas exposure under supercritical pressures and temperatures.

Geological investigation was focused on the reservoir, local, and regional (subbasinal) scales. Results of these investigations indicate that natural leakage from this system is unlikely and regional flow is extremely slow, on the order of thousands to tens of thousands of years to migrate out of the basin. The potential for leakage through existing wellbores was also evaluated and found to be very low. Geomechanical evaluations, including 3D modeling, were completed on the injection zone and adjacent stratigraphy. This series of tests confirm that the geological structures that are being utilized are excellent candidates for sequestration. The cap rock is considered to be extremely stable, has extremely low permeability, and is not likely to fracture when subjected to injection pressures well beyond the maximum allowed. Geochemical modeling aids in the understanding of the long-term fate of acid gas injected into carbonate rocks. Evaluations of the Zama system indicate that the impact of mineralization on the overall storage capacity of the system is negligible and will occur very slowly over geological time scales.

Continuous injection has taken place at a depth of 4900 feet into the carbonate pinnacle reef structure since December 2006. As of September 30, 2009, approximately 58,000 tons of acid gas had been injected into the pinnacle reef, of which approximately 40,000 tons was CO_2. Incremental oil production from the pinnacle reef over the course of the project, as of September 30, 2009, was approximately 25,000 barrels.

Project results indicated that a robust, yet practical, MVA program can be developed. Given the proper geologic setting, MVA activities can be relatively inexpensive and not adversely affect commercial EOR operations.

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INTRODUCTION

In recent years, the management of carbon dioxide (CO_2) emissions from large industrial point sources has been identified as a potential means to mitigate global climate change. Efforts to reduce CO_2 emissions now are a significant focus for all energy production and use stakeholders, including the general public, governments, industry, regulators, and environmentalists. Many large industrial CO_2 emission sources produce a gas stream that includes constituents other than CO_2. This is particularly true of natural gas-processing plants, which can have significant quantities of hydrogen sulfide (H_2S) mixed within their CO_2 stream. Such gas mixtures are commonly referred to as “acid gas” or “sour CO_2” streams. While many laboratory- and field-based research projects have focused on technical and economic issues associated with the management of CO_2, relatively few have focused on the unique issues related to the management of acid gas, which is far more toxic and corrosive than pure CO_2.

Carbon capture and storage (CCS) in geological media have been identified as important mechanisms for reducing anthropogenic CO_2 emissions currently vented to the atmosphere. Several means for geological storage of CO_2 are available, such as in depleted oil and gas reservoirs, deep saline formations, CO_2 flood enhanced oil recovery (EOR) operations, and enhanced coalbed methane recovery. These same geological formations may also be amenable to the large-scale storage of acid gas. Activities to improve understanding and develop technologies and approaches for CO_2 and acid gas capture; transportation; storage; and monitoring, verification, and accounting (MVA) have been, and continue to be, conducted. The goals of such activities are to determine the technical and economic viability of CO_2 and acid gas storage and to support the deployment of large demonstrations and, ultimately, commercial-scale projects.

The capture of acid gas from raw natural gas production streams has been economically conducted throughout the world for decades, largely through the use of amine-based acid gas removal technologies in gas-processing plants (Skinner and others, 1995; Sorensen and others, 1996). Similarly, the transportation of high concentrations of acid gas through pipelines has also been safely and cost-effectively conducted for decades, especially in western Canada where a network of thousands of wells and gathering lines have produced and moved trillions of cubic feet of methane and acid gas throughout Alberta and British Columbia for several decades (Sorensen and others, 1996). The technical and economic challenges associated with the injection of CO_2 and acid gas into geological formations are also fairly well understood, as CO_2 injection for EOR has been applied at many locations since the 1970s and the injection of acid gas for disposal purposes has been conducted in Alberta since the 1980s. However, unlike capture, transportation, and injection, the long-term permanent storage of acid gas for the mitigation of greenhouse gas emissions and the MVA required for such storage projects are in the early stages of technology development and implementation and are, therefore, less understood.

In particular, MVA activities are critical components of geological acid gas storage projects for two key reasons. First, the public must be assured that geological storage of CO_2 and acid gas is a safe operation. Second, emerging carbon credit-trading markets need assurance that credits are properly assigned, traded, and accounted for. Integrated geological and hydrogeological characterization, modelling and simulation, geomechanical testing, and geochemical sampling and analysis programs are technologies that can facilitate documentation of the movement of the injected gases and detect any potential leakage from the storage unit.

The Energy & Environmental Research Center (EERC), through the Plains CO_2 Reduction (PCOR) Partnership, one of the U.S. Department of Energy (DOE) National Energy Technology Laboratory's Regional Carbon Sequestration Partnerships, is working with Apache Canada Ltd. to conduct a program of primarily field-based activities that will support and validate the safe and cost-effective injection of acid gas into selected reservoirs of the Zama oil field for the simultaneous purposes of acid gas disposal, CO_2 storage, and EOR. The reservoirs in the Zama oil field exist in the form of isolated, porous, and permeable pinnacle reefs (carbonate rocks) which are sealed by a thick layer of essentially impermeable anhydrite. The capture, transportation, and injection processes and subsequent hydrocarbon recovery operations are being carried out by Apache Canada at its oil field and natural gas-processing plant locations near Zama, Alberta, Canada (Figure 1). The role of the PCOR Partnership is to conduct MVA activities at a specific location/reservoir (referred to as the "F Pool") within the Zama oil field. The MVA activities have been designed in such a way as to be cost-effective, cause minimal disruption to ongoing oil production activities, and yet provide critical data on the behavior and fate of the injected acid gas mixture within the reservoir.

The MVA, acid gas production, and EOR activities at the Zama oil field that are considered to be part of Phase II of the PCOR Partnership Program were conducted from October 2005 through July 2009. One of the primary purposes of the PCOR Partnership Phase II Program is to develop a Regional Technology Implementation Plan (RTIP) for each of the Phase II field-based CCS demonstrations. In the case of the Phase II activities at Zama, the purpose of the RTIP is to provide technical guidance on approaches for conducting baseline

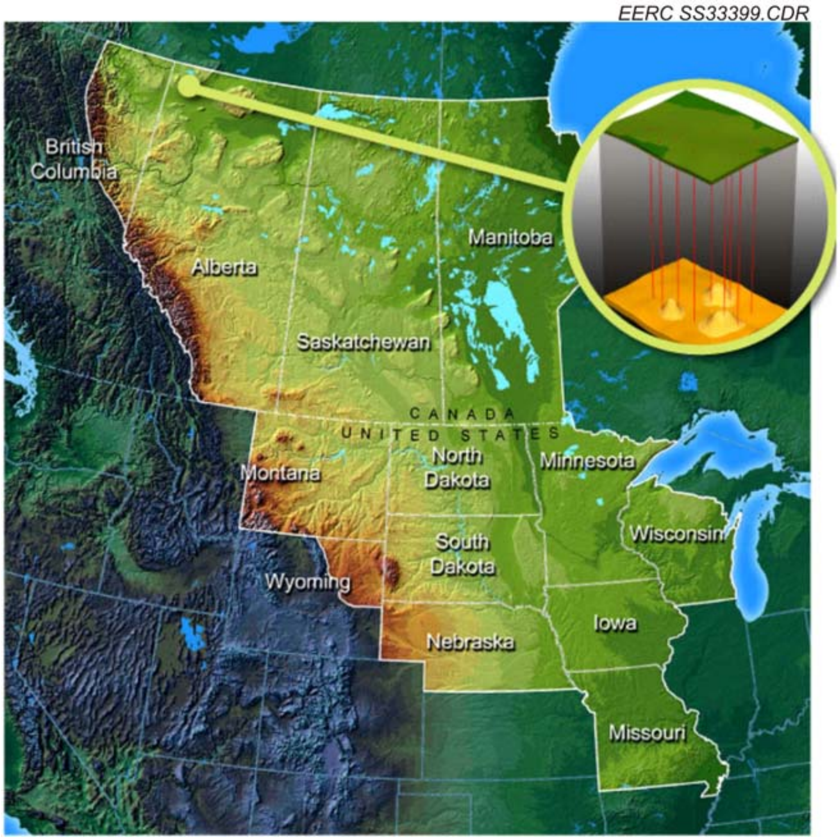

Figure 1. Location of the PCOR Partnership–Apache Canada acid gas storage field validation test in the Zama Field of Alberta.

surveys, MVA, and assessing the overall success of injecting CO_2-rich acid gas into deep carbonate oil reservoirs for the purpose of simultaneous CO_2 storage and EOR. The RTIP is not intended to be a detailed accounting of the numerous activities conducted at Zama and their results over the course of the project. Instead, the RTIP presents a series of key observations, insights, and recommendations, based on the experiences at Zama, that are intended to be broadly applicable to the injection of acid gas for simultaneous CO_2 storage and EOR operations at locations throughout the United States, Canada, and even the world. The PCOR Partnership Phase II Zama project was designed with the following goals in mind:

- To demonstrate that the capture and injection of an acid gas stream into properly characterized and carefully selected underground reservoirs is feasible and safe within existing industry and regulatory standards.

- To design, implement, and demonstrate cost-effective MVA strategies for verifying and validating the containment integrity of the target reservoirs.

- To demonstrate that highly concentrated acid gas (in this case, 30% H_2S and 70% CO_2) can be successfully used for EOR operations in a type of geological feature (carbonate pinnacle reefs) that had previously been untested with respect to acid gas-based EOR.

Philosophical Approach

There is a broad range of technologies and approaches that can be and, in some cases, have been applied to CO_2 storage projects of various scales around the world. Early geological storage research and demonstration projects deployed MVA strategies that were developed based on a lack of knowledge about the effectiveness and utility of many of the applied technologies. The absence of knowledge required early projects to gather as much data as possible using a wide variety of techniques. In particular, a desire to "see" the plume of injected CO_2 led to a strong emphasis on the use of geophysical data, especially 3-D and 4-D seismic, to monitor the plume. While the use of geophysically based approaches and techniques in early projects yielded valuable results that are essential to the development of geological storage as a CO_2 mitigation strategy, their high costs of deployment and often limited ability to identify CO_2 in many geologic settings may render them as being the exception rather than the rule when it comes to developing practical MVA plans for future projects. If the implementation of CCS is to occur on a large enough scale to mitigate global climate change, then economics must be secondary only to health and safety considerations at the earliest stages of project development. At the same time, a detailed understanding and effective demonstration of the technical feasibility with respect to injectivity, capacity, containment, and overall safety is essential for all stakeholders to buy into the concept of large-scale CO_2 and/or acid gas injection. This is the context within which a philosophical approach was developed, which was then applied to the PCOR Partnership Phase II Program.

It is expected that, in many cases, EOR projects and depleted oil and gas pools will provide the most favorable locations for long-term CO_2 storage from both a technical and economic standpoint. From a technical perspective, such sites benefit from a relative wealth of previously generated, readily available subsurface characterization and reservoir production and injection data. These data provide critical, invaluable insight regarding the long-term prospects for technically feasible and safe injection and storage of CO_2, and in this case, acid gas. From an economic perspective, hydrocarbon reservoirs (and especially those that are suitable for EOR projects) are attractive because the use of existing infrastructure can lower the start-up costs of a project, while the production of incremental oil can be used to offset the costs of capital, operations, and maintenance and, ultimately, bring profitability to the project. The use of established hydrocarbon reservoirs also benefits from the fact that a regulatory framework already exists for permitting many, if not all, of the surface and subsurface operations that will be necessary to conduct a project.

The philosophical approach of the PCOR Partnership toward the design, implementation, and operation of the MVA plan and associated project activities was to:

- Maximize the use of previously generated data on the geological, geochemical, and geomechanical characteristics of the formation into which acid gas was to be injected (target injection zone) and the overlying low-permeability rock formations that would serve as seals.

- Minimize, as much as possible, the need to obtain data beyond that which is already collected by the operator as part of the "normal" or "standard" operation of an EOR or acid gas disposal project.

For those elements of the MVA plan that required the use of new or nonstandard testing or technologies in the field, those elements would be designed in close consultation with the field managers and operators to ensure that disruption of normal oil field operations was minimized.

The application of these fundamental guiding principles to the planning and operation of the Zama project ensured that the goal of demonstrating the economic feasibility of acid gas injection for simultaneous EOR and CO_2 storage under "real world" technical and economic constraints could be achieved. That being said, the PCOR Partnership and Apache Canada recognized the value of developing previously unavailable fundamental data sets that could provide new understanding of CCS and guide the direction of future CCS research. With that in mind, the PCOR Partnership sought and, when appropriate, acted on opportunities to cost-effectively conduct additional activities that were of a more research-oriented nature and which would not typically be part of future nonresearch EOR and/or CCS projects.

Technical Approach

For purposes of discussion in the context of this report, the technical aspects of the PCOR Partnership Phase II–Apache Canada project at Zama generally can be thought of as falling into two categories: 1) the MVA program and 2) the injection program. These categories are not necessarily independent of each other, with some activities and data sets being common between the two categories. However, for the sake of effective discussion in the context of the RTIP, they are presented in this report in relatively independent sections, with categorization based largely on what was deemed to be the primary purpose of each activity.

The purpose of the MVA program is to 1) provide a set of baseline conditions upon which the effects of the project can be compared to data gathered during and after injection operations; 2) generate data sets that demonstrate the security of the injection program from the perspectives of containment and safety; and 3) establish a technical framework for the creation and ultimate monetization of carbon credits associated with reduction of emissions and the geological storage of CO_2 at Zama. MVA program activities that resulted in the determination of baseline conditions include geological and hydrogeological characterization at various scales, characterization of the F pool reservoir, determination of geomechanical and geochemical properties of key rocks in the reservoir/seal system, and evaluation of wellbore integrity issues. Field-based elements of the MVA program include the introduction of a tracer and data collection (i.e., formation fluid sampling and analysis, reservoir dynamics monitoring) from the injection, production, and monitoring wells. Other key elements of the MVA program include documentation of the permitting process and regulatory framework for the project, determination of material balance based on the collected field data, and a modeling-based study of historical and new reservoir pressure data in an effort to maximize the use of pressure data as a means of early identification of leakage. Generally speaking, monitoring activities are focused on the near-reservoir environment, including monitoring for leakage through cap rock, wellbore leakage, and spillpoint breach (Figure 2).

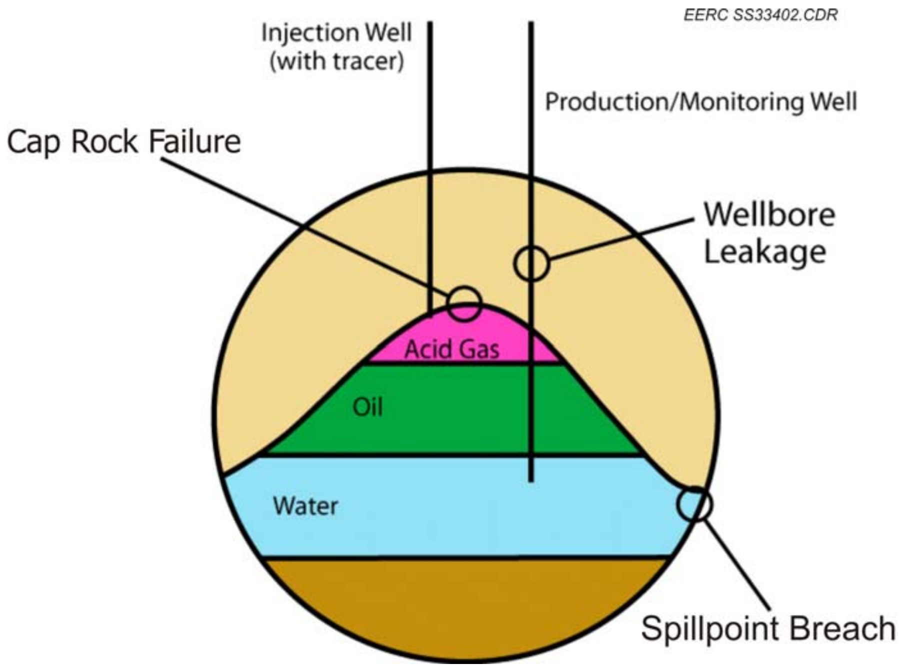

Figure 2. Monitoring activities at Zama, focused on assessing the potential for leakage out of the reservoir through the cap rock, wellbores, and spillpoint at the base of the structure.

The purpose of the injection program is to 1) ensure the cost-effective injection of acid gas from the Zama gas-processing plant into the Zama F Pool reservoir; 2) facilitate the production of incremental oil from the F Pool reservoir; and 3) support the documentation of effective CO_2 storage in the F Pool. Key aspects of the injection program include the capture and infrastructure elements of the project, well preparation and maintenance activities, and acid gas injection and EOR operations.

The PCOR Partnership Phase II–Apache Canada project at Zama was conducted by a multidisciplinary team of engineers, scientists, regulators, and management personnel. The management team for the project included representatives from Apache Canada and the EERC. The primary technical team comprised technical professionals from Apache Canada, the EERC, the Alberta Energy and Utilities Board (AEUB), the Alberta Geological Survey (AGS), RPS Energy, Schlumberger Oilfield Services, and Advanced Geotechnology Inc. Effective, frequent communication between all team members was critical to the timely, cost-effective design and implementation of all project activities. To facilitate communication and the appropriate sharing of project data, conference calls were held on at least a quarterly, often monthly, and sometimes weekly basis. A password-protected file transfer portal (FTP) site was established for the easy sharing of documents and data between members of the technical team. Integration of activities in a cross-disciplinary manner facilitated efficient implementation of project plans. Such integration, while effective from a project management and budget standpoint, sometimes blurred the lines between the various elements of the program, which further underscored the need for frequent, diligent reporting of activities and results and thoughtful, interpretive discussion between team members.

BACKGROUND

Zama Location and General Geological Setting

The Zama oil field is located at 59° latitude in the extreme northwestern corner of the province of Alberta, approximately 875 km (550 miles) northwest of Edmonton, as shown in Figure 1. The gas plant is situated within the boundaries of the oil field and is approximately 1 km west of the F Pool injection site (Figure 3). The field covers an area of about 2000 km^2 (500,000 acres) in an area known geographically as the Fort Nelson Lowland. The Fort Nelson Lowland plain is characterized by boreal forest, extensive bogs, fens, muskeg, surface water accumulations, ox bow lakes, and meandering water courses. The area is subject to typical northern latitude interior plains weather patterns, including severe cold winter temperatures and summer thawing, which turns most of the flat country into very wet marshland, as illustrated in Figure 4.

From a geologic perspective, the Zama area is located in the Zama subbasin which, in turn, is in the northwest portion of the Alberta Basin. The F Pool is one of hundreds of pinnacle reef structures that comprise the oil reservoirs of the Zama oil field. Pinnacle reefs at Zama are steep-sided, moundlike carbonate structures in the Keg River Formation, having an average size of 40 acres at the base and 400 ft in height. The depth from surface to the pinnacles is typically 4900 ft. The reefs are typically dolomitized, with variable porosity (average 10%) and permeability. The pinnacle reefs are encased laterally and vertically by essentially impermeable anhydrites and underlain by a brine-saturated formation. Figure 5 presents a cartoon representation of the general structure, in cross-section view, of the pinnacle reefs and their relationship to overlying seals, aquifers, and hydrocarbon reservoirs. The stratigraphic and structural isolation of the pinnacles, their adequate porosity and permeability, and the close proximity to an anthropogenic source make them suitable candidates for conducting a CO_2 sequestration technology validation test. Beyond Alberta, similar pinnacles are known to occur in the Saskatchewan and North Dakota portions of the Williston Basin as well as in the Michigan Basin.

Overview of the Zama Oil Field, Keg River F Pool Operational History

The Keg River F Pool began producing oil in 1967. The well produced 170,750 m^3 (1.1 MMbbl) of oil over a 20-year period. In late 1986, oil production was discontinued, and the well was completed as a saltwater disposal well in October 1987. Water injection operations were suspended in October 1991, with a cumulative water injection of about 1.8 MMbbl (287,500 m^3). In 1992, an attempt at secondary oil production was unsuccessful, with little incremental oil being produced. The waterflooding of small pinnacles, such as the Zama Keg River F Pool, was found to be challenging because of their small size and heterogeneity with respect to porosity and permeability.

In June 1997, the well completion in the Keg River Formation was abandoned, and the well was recompleted as a gas well in the Slave Point Formation (referred to as the Slave Point FFF Pool). The gas completion watered out and was suspended in November 2006. This completion (Slave Point FFF) is suspended at surface (meaning it no longer produces gas but has not been completely shut in) and, as a result of this project, is now utilized as a monitoring well

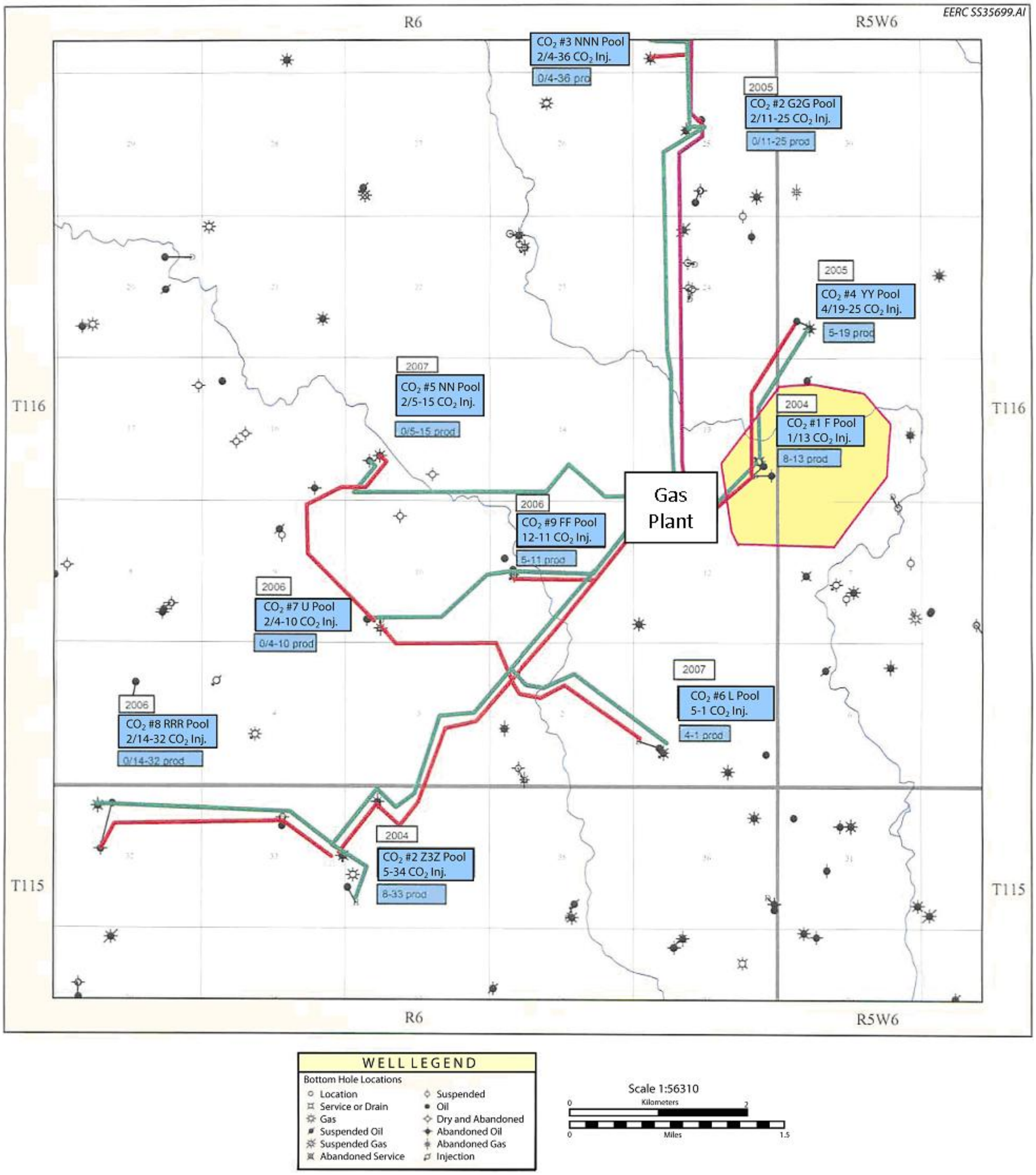

Figure 3. Map view of Zama showing the F Pool (shaded in yellow) in relation to the gas plant.

Figure 4. Flooded areas of the Zama Field. Specialized transportation required to navigate the muskeg that dominates the area.

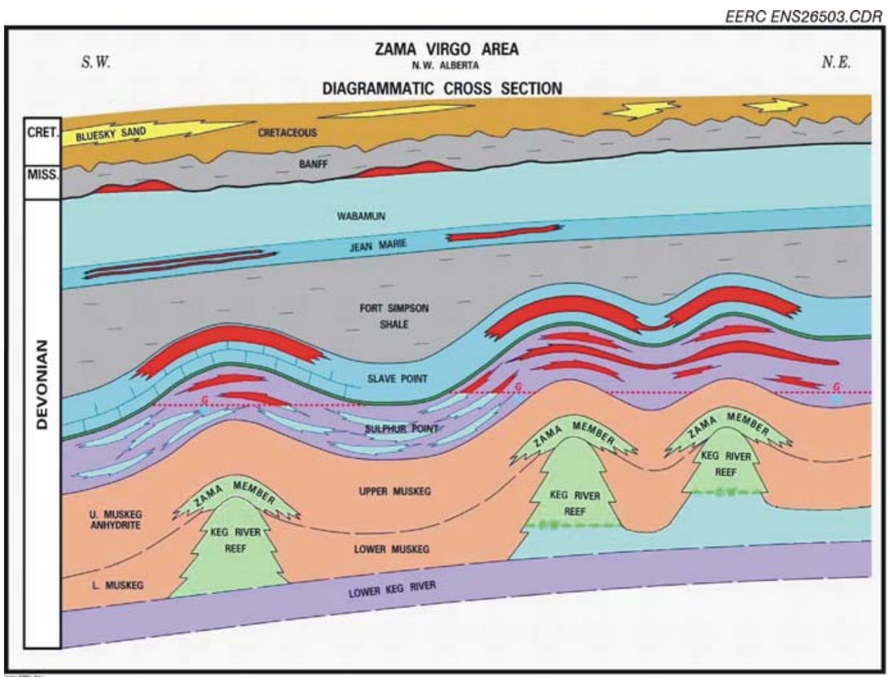

Figure 5. AGS diagrammatic cross section of the Zama area. Light green areas of the Keg River reefs represent accumulations of oil. Red areas represent accumulations of natural gas. Blue areas represent permeable brine water-saturated zones.

for potential wellbore leakage of gas injected into the Keg River F Pool. A second well was drilled into the Keg River F Pool in January 2002 and encountered oil at the top and center of the

F Pool pinnacle. It was completed as an open hole and placed in production in March 2002. Production was suspended in early 2004 after producing just 5438 m^3 (34,220 bbl) of oil.

In July 2004, following project planning, including reservoir, geological evaluations, and economic evaluations, Apache made an application to the Energy Resources Conservation Board (ERCB) to conduct an acid gas miscible flood. Petroleum engineering studies and lab work were also carried out in support of this application, including well and reservoir review, miscibility studies, statistical analysis of oil compositions in the area, and estimates of miscible flood efficiency. The original ERCB approval stipulated operational limits for the F Pool EOR scheme, some of which were altered following the application and approval process to allow for changes in the acid gas miscibility pressure.

A third F Pool production well was drilled in September 2004. The well was placed in production in August 2005. Perforated low in the formation, it was a poor producer, with a cumulative oil production of about 75 m^3 (470 bbl) between August 2005 and May 2006. This well was then utilized to draw water off the lower portion of the pinnacle to lower the average reservoir pressure down to the original ERCB-approved range beginning in November 2006. This objective was accomplished by May 2006 but injection was not started until December 2006. By that time, injection of acid gas into other pinnacle reefs (pools) in the Zama Field had already begun, and the Zama Keg River F Pool became the third pool in the Zama oil field to be placed on acid gas EOR. Tables 1 and 2 present the cumulative oil production history of the Zama Keg River F Pool and its preinjection reservoir conditions, respectively. Figure 6 depicts a producing oil well in the F pool.

Overview of the Zama Gas-Processing Plant

The Zama gas plant is owned and operated by Apache Canada. The plant currently generates about 7.5 million cubic feet per day (7.5 MMcf/day, 210,000 m^3/day) of acid gas consisting of 20% to 40% H_2S and 60% to 80% CO_2. This amounts to a total of about 273 metric tons/day of CO_2 and 84 metric tons/day of H_2S. The Zama gas plant and oil production facility (Figure 7) was modified to accommodate the acid gas EOR/CCS project. Following these modifications, the Zama gas plant consists of the following process elements:

- Production gathering system
- Conventional oil and gas processing, sales, and shipping
- Conventional gas compression
- Acid gas compression and injection
- Gas recycle stream

Table 1. F Pool Cumulative Recoveries to November 2003

Oil	1,107,512 bbl	176,100 m^3
Gas	533,604,614 ft^3	15,110,000 m^3
Water	405,647 bbl	64,500 m^3
Water Injection	2,304,329 bbl	366,400 m^3

Table 2. F Pool Initial Conditions

Plan Type	Keg River Pinnacle Reef
Initial Reservoir Pressure	2095 psi (14,447 kPa)
Reservoir Temperature	160°F (71°C)
Initial Water Saturation	15% (from logs)
Porosity	10% (from logs)
Initial Gas Oil Ratio	52 m^3/m^3
Initial Formation Volume Factor	1.183 r vol/std vol
Bubble Point Pressure	1275 psi (8791 kPa)
API[1] Gravity	35.2 API
Calculated OOIP[2]	2.2 million bbl
	344,000 m^3 (volumetric using 3-D seismic data)
Calculated OOIP	3.5 million bbl
	557,000 m^3 (material balance)

[1] American Petroleum Institute.
[2] Original oil in place.

EERC SS35579.CDR

Figure 6. Oil production well in the Keg River F Pool of the Zama oil field.

Figure 7. Apache Canada Zama gas plant and oil production facility.

Prior to the EOR/CCS demonstration project, the acid gas stream from the Zama gas-processing plant was processed through a Claus sulfur recovery unit to produce solid elemental sulfur, which was then stored until market conditions would allow its sale; CO_2 was vented to the atmosphere during these plant operations. A very significantly sized storage site within the Apache Zama production facility was required to house this by-product of the gas-processing operations. The remainder of the acid gas stream processed was injected for disposal in the Keg River Formation via acid gas disposal wells.

The injection of the acid gas for the EOR project permitted the shutdown of the Claus unit, and the gas plant was reconfigured to inject the entire acid gas stream into the Keg River EOR pools. The elimination of the sulfur production and storage is a major environmental benefit in addition to the simultaneous elimination of the CO_2 venting (64,000 tons per year).

The current Zama natural gas operation has resulted in significant reduction of the operating costs that were associated with the sulfur plant. Further revenue could result if EOR is feasible using miscible acid gas flooding. This value-added approach could be used to manage CO_2-rich acid gas streams at many of the more than 1300 gas-processing plants in North America as well as others worldwide.

MVA PROGRAM

The goal for the PCOR Partnership MVA activities at the Zama site was to establish the integrity of the Zama pinnacle reefs for CO_2–H_2S storage. This was accomplished by carrying out the following activities:

- Going through the regulatory process
- Data reconnaissance and integration
- Baseline geology and hydrogeology characterization
- Rock mineralogy and composition of formation water determination
- Mechanical rock properties and stress regime evaluation
- Assessment of geochemical interactions between formation and injected fluids and reservoir rock and cap rock
- Assessment of wellbore integrity and leakage potential

Regulatory Process

While the regulatory process for any given acid gas injection project, whether it be for EOR, CCS, or both, will vary depending on the jurisdiction within which the project is operated, it is instructive to briefly summarize the process that Apache Canada went through for the project at Zama. As operator, Apache Canada is committed to developing the Zama acid gas injection EOR and CCS project in a manner that complies with all current Alberta ERCB oil and gas regulations. Well completions, facility and gathering system modifications, and reservoir engineering practices were all conducted within industry-recommended practices (IRP), including the practices and standards of API and the National Association of Corrosion Engineers. In many cases, these standards and practices are consistent with regulatory requirements and guidelines, although it is important that this be determined definitively by the operator early in the planning stages for any CCS project.

To convert an oil field to an acid gas injection process in Alberta, a formal application must be made to the Resource Applications Department of the EUB (ERCB) under Section 26(1)(a) of the Oil and Gas Conservation Act (Alberta Oil and Gas Conservation Act, 2009). Specifically, EUB Directive 65 (Energy Resources Conservation Board, 2009) must be followed. It is then required to file a separate application for each pool, which references the original application approval. Also required is Directive 51 (Energy Resources Conservation Board, 1994), compliance planning for injection wells, and a site-specific Emergency Response Plan (ERP) (Energy Resources Conservation Board, 2008). Wellhead components must meet product specification level (PSL) III requirements according to API Standard 6C.

Because of the site-specific nature of the application for the F Pool acid gas injection, a full presentation of the elements of that application is beyond the scope of this discussion. The complete application and subsequent amendments submitted by Apache Canada for the F Pool acid gas injection scheme are included as Appendix A of this report. In addition to this main application, a holding application under ERCB Directive 065 was also required to be able to place more than one production well within a ¼ section drill spacing unit. The original application provided a project challenge in that the first pool approval for the Z3Z pool was received 388 days after submission; this was twice the expected length of time and significantly delayed project start-up.

Data Reconnaissance and Integration

Efficient data acquisition, evaluation, and integration through the use of data management tools are crucial early steps in the establishment of baseline conditions. Data reconnaissance and integration activities for the Zama project included the following:

- Well/reservoir information of the pertinent formations.
- Data on drilling, completion, and stimulation/workover of key wells in the area.
- Digital production/injection history of key wells.
- Geological and geophysical information on the key formations in the study area, including formation isopach and depth maps, interpreted seismic data, hydrogeological characteristics, etc.
- Reservoir engineering data on injection zone characterization and acid gas injection/monitoring schemes.

Baseline Geological and Hydrogeological Characterization

Identifying and characterizing the geological setting and hydrogeological regime at an acid gas–CO_2 injection site is important to understand possible migration pathways and the effect the flow of formation water may have on the spread of the injected gas. The Devonian Keg River Formation and its associated pinnacle reefs are part of the Keg River saline aquifer system. Several aquifer systems (Figure 8) are present in the sedimentary succession overlying the Keg River Formation: 1) the Devonian Sulphur Point saline aquifer; 2) the Devonian Slave Point saline aquifer; 3) the Upper Devonian saline aquifer system, which includes carbonates of the Winterburn and Wabamun Groups; and 4) isolated sand aquifers in the shales of the Lower Cretaceous Fort St. John Group (Bluesky and Paddy Formations). The following information was collected as part of the Zama characterization activities and should be a part of any characterization program for a CCS project:

- Hydrostratigraphic delineation
- Aquifer and aquitard geometry and thickness
- Rock properties relevant to the flow of formation waters and injected acid gas such as porosity and absolute and relative permeability
- Geothermal regime
- Pressure regime

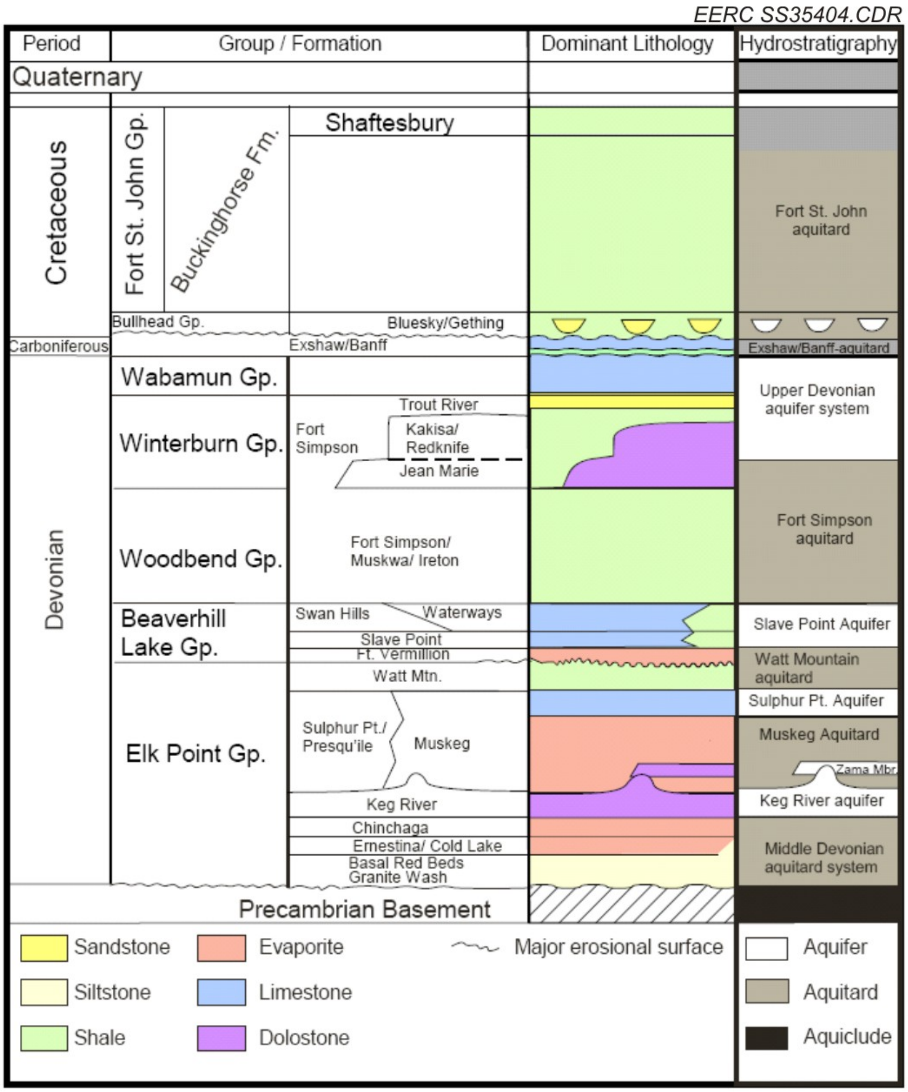

Figure 8. AGS northeast Alberta stratigraphic and hydrostratigraphic section.

- Direction and strength of formation water flow

A model of the flow-driving processes and mechanisms in the region and strata of interest were developed from those data that help in understanding the effect of natural flow on flow paths in the aquifer intervals of the Zama study area and outside, in case of leakage, and also of the effect of injection on the Keg River saline aquifer system. The results of the modeling showed that barring major leakage through a wellbore, the current and planned acid gas injection at Zama will have minimal impact on the hydrogeologic regime of any of the Devonian Aquifer systems in the area. The study also showed that even if injected acid gas were to make its way into any of the Devonian Aquifer systems, the direction and strength of formation water flow in those systems are such that it would take thousands of years for the acid gas to migrate to any formation outcrop. These results are a key component to demonstrating long-term containment of the injected acid gas and safety.

The geology and hydrogeology characterization work was carried out at four different scales (Figure 9):

- Reservoir scale
- Local scale
- Regional or subbasin scale
- Basin scale

Work at the **reservoir scale** focused on the Zama F oil pool and the immediately underlying and overlying confining units: Lower Keg River Formation limestone and Muskeg Formation anhydrite. This, the smallest of scales, provides insight into predicting the immediate and early near-term effects of the injection operations. This is the most detailed portion of the baseline characterization and will be the most frequently updated over the course of any injection program. This is because data generated over the course of the injection, such as history matching injection and production curves, will provide new insight regarding the characteristics of the reservoir.

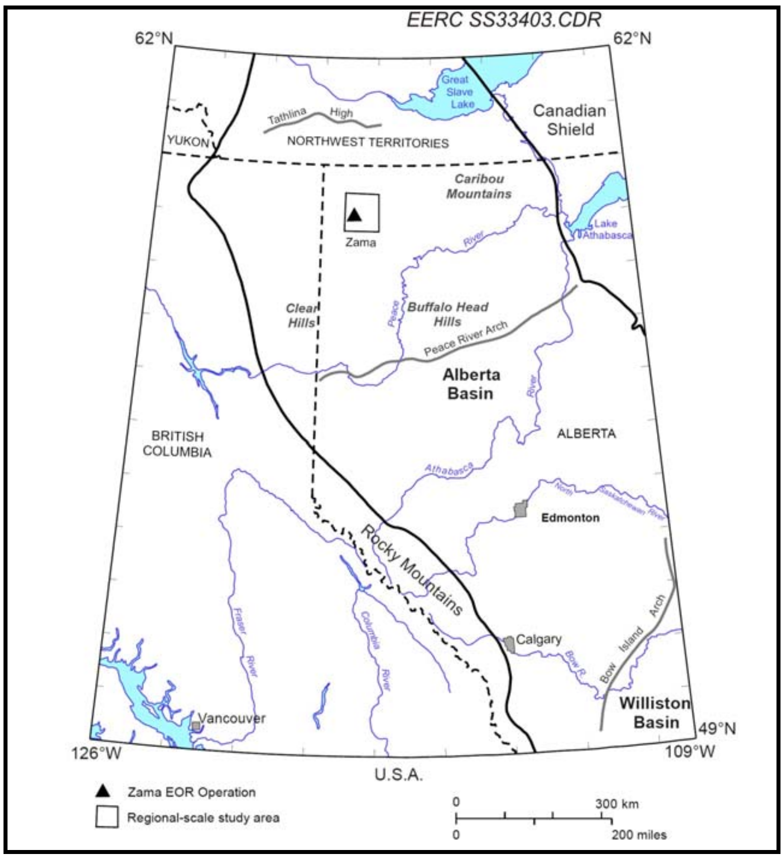

Figure 9. AGS Zama geological and hydrogeological study area. The triangle represents the local (or field) scale, the square represents the regional scale, and the black outline around the Alberta Basin represents the basin scale. The reservoir scale, which is the F Pool pinnacle reef, is too small to be represented on this map.

Work at the **local scale** covered areally the Zama F Pool and a few adjacent pinnacle reefs and, stratigraphically, the entire sedimentary succession from the basement to the surface. This scale generally includes the oil field within which the individual pool is a part. As with work done at the reservoir scale, work at the local scale can be used to predict near-term (months to years) effects of injection. These data can typically be updated on a relatively frequent basis as data from injection or production activity in wells in this area will typically be generated according to a schedule similar to the target reservoir.

Work at the **regional**, or **subbasin scale**, focused on evaluating relevant data and information from the basement to the surface over the entire Zama oil field/subbasin. This scale generally is defined according to the geological setting of the area within which the local scale area sits, but is generally much larger than the local scale (up to several hundred square miles). Examples typically include large structural features such as subbasins, but could also be defined by the extent of a particular formation of interest whose areal extent is not necessarily defined by a structural feature. Evaluations at this scale can provide insight that is useful in predicting the medium- to long-term (decades to hundreds of years) effects of large-scale injection operations, particularly if multiple projects are planned.

Work at the basin scale was primarily conducted with respect to large-scale hydrogeological characteristics. Basin-scale studies of aquifer system dynamics (flow, temperature, salinity, hydraulic head, etc.) will provide insight regarding the very long-term (hundreds to thousands of years) effects of large-scale CO_2 or acid gas injection. This is also the scale at which multiple large-scale injection projects should be evaluated.

At the reservoir and local scales, a geological model of the strata associated with the Middle Devonian Keg River Formation at the F Pool EOR site was generated to evaluate reservoir geometry and internal architecture. The Keg River pinnacle reef reservoirs are confined above by 70 m of Muskeg/Prairie Formation evaporites and underlain by the Lower Keg River carbonate platform, which consists of tight lime–mudstone and a slightly porous limestone. The carbonates are also underlain by about 70 m of Chinchaga Formation evaporites. The overlying/surrounding cap rock was also evaluated, as well as the underlying aquifer that provides reservoir support in places. Information about the geology of the reservoir and confining strata (e.g., structural setting, stratigraphy, general lithology; thickness; and areal extent) were collected, processed, and interpreted for the local-scale area.

At the regional scale, the geology, stratigraphy, and lithology were evaluated, delineated, and described for the entire sedimentary succession from the base of the Middle Devonian Elk Point Group (lower confining unit) to the surface (Lower Cretaceous Fort St. John Group and Quaternary drift) for the Zama subbasin (Figure 8). In addition, the structural elements in the area, from the basement to the surface, were investigated to identify any possibly existing faults and/or fractures that would allow migration of reservoir and injected fluids. On this basis, a geological model (Figures 10–12) of the entire sedimentary succession was built, with particular attention given to the strata overlying the Keg River injection interval.

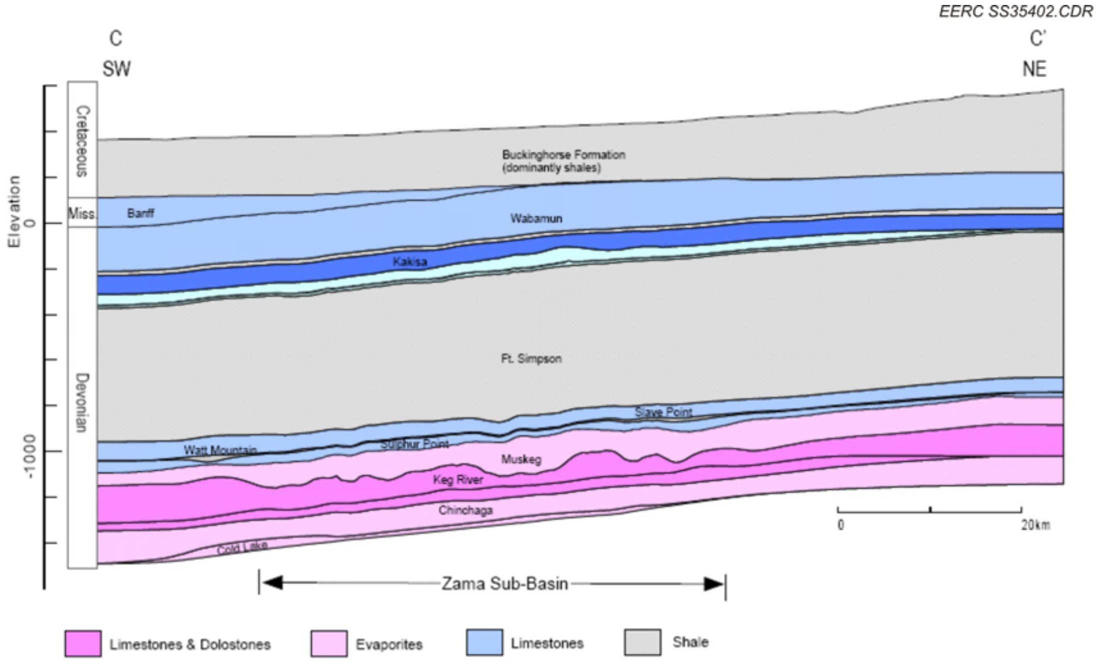

Figure 10. AGS Zama Keg River cross section.

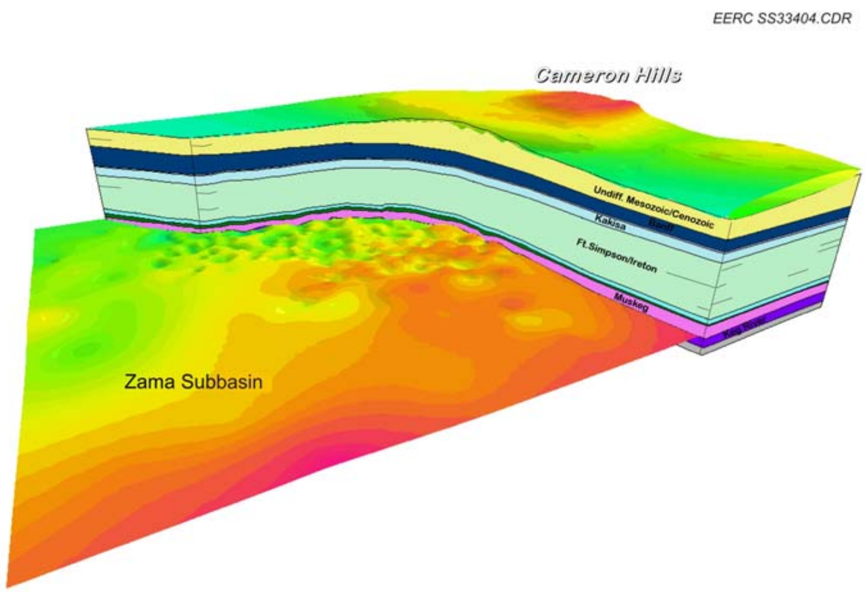

Figure 11. Cross section of the Zama subbasin showing regional structural architecture. The texture seen in the cutaway is the result of individual pinnacle reef structures sitting on the Keg River platform.

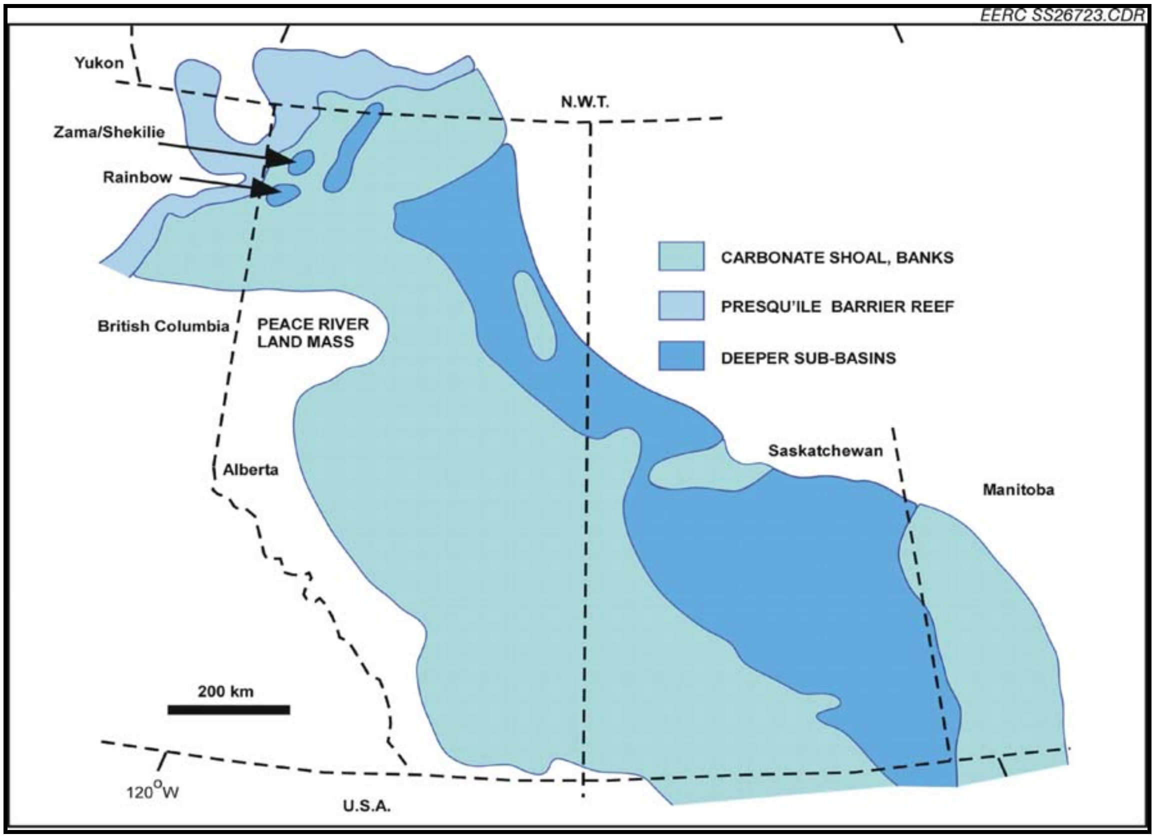

Figure 12. Simplified paleogeography of the Keg River carbonate from basin-scale assessment.

Rock Lithology, Mineralogy, and Composition of Formation Fluids

Data regarding key properties of the reservoir rocks and fluids are critical to 1) determining the feasibility of a potential injection location for large-scale CCS and 2) predicting the short-, medium-, and long-term effects of injection on the reservoir. Because the Zama project was conducted in an oil field that has been operating for several decades, a tremendous amount of lithology, mineralogy, and formation fluid baseline characterization data had been generated long before the acid gas injection project was planned. This made the drilling of an exploration well at Zama unnecessary. However, projects that are planned to be conducted in areas that are underexplored and less understood, such as in a saline formation, should include the drilling of an exploratory well as an early part of the characterization process. Exploration wells can provide project planners with a variety of data that are critical to establishing the efficacy of large- scale injection and storage at a given site. These data are an excellent means of providing support to a variety of preinjection modeling activities, including the development of static petrophysical models, site-specific geomechanical and geochemical modeling, and simulations of injection and plume transport and fate. An exploration well characterization program should include the following elements:

- Collection of core and cuttings
    - Cuttings should be collected at regularly spaced intervals (5 m is typical industry practice) from surface to total depth of the well. Cuttings provide information on the lithology of the site, including the depth and thickness of such key intervals as potential injection zones, seals, and aquifers that need to be protected.
    - At a minimum, core should be collected from the primary target injection zone. If possible, core samples of the primary seal should also be collected, although it is worth noting that some shales that can serve as perfectly competent seals may not yield good core samples because of their friable nature. The collection of core from secondary target injection zones and seals should also be considered. It is also worth noting that the collection of core samples should be supervised by wellsite geologists and drillers who have experience drilling in the local area. Knowledgeable geologists and drillers will have a keen understanding of the typical depths and thicknesses at which specific formations and zones within formations are likely to occur in a given area, which is information that is critical to the successful collection of core samples.
    - Core samples should be collected and preserved to allow for detailed description and testing. Core tests should include a variety of mineralogic, physical, and geomechanical parameters, including relative permeability of acid gas and brine and dynamic and static compressibility, among others.
- Collection of formation fluids and fluid testing
    - Collection of downhole reservoir fluid samples, preservation at reservoir pressure, and subsequent analysis will yield invaluable data regarding the geochemical regime of the target injection zone. Geochemical analyses should include specific gravity, salinity, resistivity, total dissolved solids, anions, cations, organic acids, metals, and gas analyses (including hydrocarbons).
- Collection of open hole geophysical logs
    - A suite of open hole logs should be run that includes, at a minimum, density, neutron, caliper, dipole sonic, and a microimaging tool. These logs will provide key rock property data including porosity, resistivity, general lithology and, to a lesser extent, permeability. Other specialized geophysical logs can be used to determine the saturation of various phases (e.g., gas, brine, and oil) within a reservoir and other useful reservoir properties.
- Cement bond and casing integrity logging
    - Cement bond and casing integrity logs will demonstrate the integrity of the casing and cement of the exploration wells and provide crucial data that will support the development of casing and cementing scheme designs for future injection and monitoring wells in the area.

- Application of drill stem tests (DSTs)

  - DSTs should be run in all zones within the well that are being considered as potential injection zones. A DST will provide information on the type and basic characteristics of fluid in the zone being evaluated and the rates at which those fluids can be produced, which yields important information on the injectivity of the formation. Pressure data from a DST can be used to calculate formation pressure, permeability, and the amount of formation damage incurred by the drilling and completion of the well (Hyne, 1991).

- Pressure transient analyses

  - A pressure transient test in a single well can be used to evaluate pressure variations in the target formation as a function of time. The pressure transient test is used to qualitatively identify the parameters that control injection such as formation permeability and thickness, skin effect, static reservoir pressure, and reservoir boundaries and limits. Types of pressure transient tests include drawdown, buildup, and falloff tests (Hyne, 1991). Analyses will support injection design and pressure buildup/falloff prediction.

- Initiation and completion of mini-frac tests

  - A mini-frac is a small fracturing treatment used to acquire data that will confirm the predicted response of the interval being tested to increases in pressure. The mini-frac procedure provides key design data from the parameters associated with the injection of fluids and the subsequent pressure decline (Schlumberger Oilfield Glossary, 2009). In the case of a CCS project, current regulatory principles typically preclude injection that goes beyond a preset reservoir pressure threshold. The purpose of the pressure threshold is to minimize the risk of injection-induced fracturing of both the reservoir and the overlying seal rock. It is recommended that, at a minimum, a mini-frac test be conducted on the primary seal formation. These data can be used to evaluate the competency of potential sealing formations and provide quantitative measurements that support the determination of an appropriate injection pressure limit that is based on site-specific data rather than generalized rules of thumb.

Baseline Reservoir Conditions

Oil production commenced in November 1967. A summary of cumulative recoveries is shown in Table 2. During the 1990s, the F Pool was shut in. This resulted in reservoir pressure being recharged as a result of water injection activities in nearby Keg River Formation locations. Current reservoir pressure is assumed to be in the vicinity of 2466 psi (17,000 kPa) at the reservoir datum depth, based on a measurement taken in December 2004. Reservoir pressure was reduced a further 2 MPa (to 15,000 kPa) between July 2005 and February 2006 to comply with EUB requirements before initiating acid gas injection.

Mechanical Rock Properties

The goal of the geomechanical characterization program is to establish the geomechanical properties of the key sink and seal formations and the stress regime in the area to assess the mechanical integrity of the system and potential for rock fracturing. An in-depth review of the stress regime and structural features in the Zama F Pool reservoir was conducted to identify structures such as faults or fractures. Zama project activities included a variety of laboratory and field-based investigations. Laboratory-based activities using core samples of Keg River reservoir rock and Muskeg anhydrite cap rock collected from the original F Pool well drilled in 1967 included compression tests to determine rock strength, static and dynamic elastic properties, compressibility, and stress-dependent permeability; and sonic tests to determine compressional and shear wave velocities. Field-based activities included in situ stress orientation and magnitude analysis, including log-based analysis of rock mechanical properties such as dynamic elastic properties and stress regime. Regional minimum stress orientation was determined using borehole breakout data from a number of wells in the Zama area. Analytical work also included using the laboratory and field-based data to correlate static-to-dynamic elastic properties, conduct geomechanical simulations, and assess overall reservoir and cap rock integrity. Figure 13 illustrates the workflow for geomechanical studies that was used by Advanced Geotechnology Inc. (AGI) on the Zama acid gas injection project.

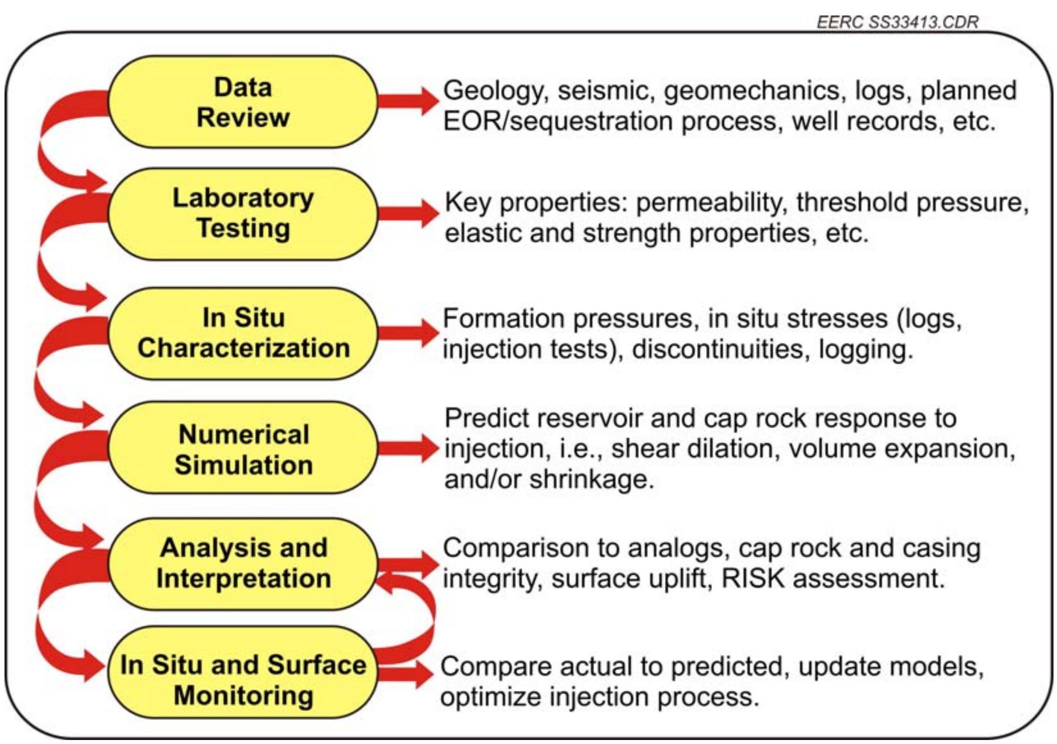

Figure 13. AGI geomechanical workflow.

The results of the Zama geomechanical studies have been presented in detail in Smith and others (2008) and their presentation here is beyond the scope of this report. However, some key results are worth noting. The peak strength data indicate that both the reservoir rock and the cap rock are relatively strong carbonate rocks and are very strong when compared to sedimentary rocks such as sandstones. The single Keg River dolomite sample exhibited a compressive strength of 24.6 kpsi (168.5 MPa) with a relatively stiff Youngs Modulus of 6193 kpsi (42.7 GPa). The Muskeg cap rock samples, whether dolomite or anhydrite, showed sample variability but, in general, were about equal to or significantly greater in strength than the more porous reservoir rock. When combined with data from laboratory pore entry mercury injection pressure tests and mechanical stress testing on similar area cores, plus log analyses and drilling reports, there is strong evidence that the thick 200- to 300-ft (60- to 90-m) Muskeg Formation dolomite/anhydrite sequences provide a competent, dense, essentially impermeable cap rock above the Keg River pinnacles. The data show that these rocks can sustain high stresses without experiencing significant deformations and that failure of the cap rock should not occur under normal operating conditions. The data further suggest that the F Pool pinnacle integrity far exceeds the current ERCB EOR pressure limit, and it could be proposed that once the EOR recovery is completed, additional CO_2 and/or acid gas volumes could be stored within this pinnacle by increasing the allowable storage pressure beyond the original reservoir pressure.

Geochemical Interactions Between Acid Gas and Reservoir/Seal Rocks

Understanding the geochemical interactions between injected fluids (i.e., CO_2 and/or acid gas) is critical to predicting both the effects of such injection on reservoir and seal rocks and the ultimate fate of the injected gases. The geochemistry-related activities that were conducted as part of the Zama project were focused on gathering relevant mineralogy and geochemistry data and assessing, through the use of geochemical modeling, the interaction between the injected gas, the reservoir fluids, and the rocks. The goals of these activities were to determine 1) the potential amount of CO_2 and/or H_2S that may be stored through mineral precipitation and 2) the effects of mineral precipitation on permeability and injectivity. The specific elements of a geochemistry evaluation for any given CCS project will be site-specific, depending on the nature of the rocks, formation fluids, and injection stream that will be involved. However, in general, geochemistry evaluations for CCS projects should include detailed analytical data on mineralogy from core or cuttings of the injection target zones and associated cap rocks being considered, rock property data such as porosity and permeability, and detailed data on the chemical characteristics of both the formation fluids and the injection stream. Mineral compositions can be obtained by scanning electron microscopy (SEM), x-ray diffraction (XRD), and x-ray fluorescence (XRF) techniques. Fluid chemistry data can be obtained from the analysis of samples of formation fluids, preferably samples that were collected and preserved at reservoir pressure. The mineral and fluid compositional data can then be used to perform geochemical modeling to assess the long-term fate of acid gas in the subsurface. A wide variety of geochemical evaluation activities were conducted for the Zama project, and a full presentation of all of those activities and results is beyond the scope of this document. However, some of the activities and their results are notable and are described below.

The Alberta Research Council (ARC) performed numerical simulations to examine the behavior of the CO_2 and H_2S components of the acid gas after injection into a depleted reservoir.

The reservoir and process conditions were based on the conditions associated with injection into the Slave Point Formation in the Zama Field. The composition of the acid gas was assumed to be 70% CO_2 and 30% H_2S, and the temperature and pressure of the reservoir were assumed to be 50°C and 14 MPa. The reservoir mineralogy was identified as calcite, quartz, and dolomite, with trace amounts of clays. In addition, there is an appreciable amount of iron within the carbonate minerals. The modeling was performed using the reservoir simulator GEM™ (Computer Modelling Group), which has the capacity to model the flow of fluids and reactions between minerals and aqueous fluids.

The modeling results demonstrate that the leading edge of the acid gas plume will become enriched in CO_2. This observation is in agreement with recently reported field, lab, and modeling results (Talman and Perkins, 2009). The enrichment is due, at least in part, to the preferential absorption of H_2S into the aqueous phase. However, in the presence of reactive iron-bearing minerals, other processes can lead to the separation of the two gases. As the acid gas plume reacts with the carbonate minerals, significant amounts of iron and bicarbonate are added to the water. This iron rapidly precipitates as an iron sulfide when H_2S is present in the gas phase. The iron sulfide precipitation produces a significant amount of acid; this acid drives much of the bicarbonate out of aqueous solution, leading to further CO_2 enrichment in the gas plume.

Numerical modeling simulations were also conducted as part of the ARC geochemistry work. Simulations were run for 200 years following acid gas injection. The numerical results indicate that significant concentration gradients may remain in the reservoir at the end of this time. Dense, CO_2/H_2S-rich gas compositions will exist at the bottom of the reservoir, with primarily methane-rich gases existing near the top. This behavior was found to be sensitive to the choice of the diffusion coefficients that are used in the model.

These modeling results demonstrate that the behavior of injected acid gas can be significantly affected by the presence of reactive iron minerals in the reservoir. Furthermore, these results indicate that the vertical variations in the gas-phase composition may be significant, so that the upper reaches of a storage reservoir may not be significantly affected by the injection (Talman and Perkins, 2009).

The Zama geochemistry evaluations also examined the relationships between geochemical interactions and effects on permeability of reservoir and seal rocks. Examination of the literature shows that certain natural CO_2 reservoirs have experienced a defined (and measurable) natural leakage rate (Le Guen and others, 2008; Zhaowen and others, 2005). While it is expected that the very low permeability of the Muskeg cap rock will contain the injected CO_2 and other acid gas components, it is also known that capillary fluid entry and/or interfacial fluid tension (IFT) will allow some restricted fluid to imbibe into the cap rock. It is possible that, in some cases, there will be low levels of sustained diffusion into the cap rock in direct contact with the reservoir. While it seems clear that existing natural micro-fractures or flaws in the cap rock are of more concern, this IFT-related issue has generated a significant volume of technical literature and was examined in the context of acid gas injection at Zama.

Aqueous acid gas mixtures do typically have lower IFT pressures than the hydrocarbons that were originally trapped by the cap rock (Nelson and others, 2005; Oldenburg and others, 2002; Ostrowski and Ulker, 2008). Therefore, it may be optimistic to assume a reservoir that successfully contained hydrocarbon reserves (or even high-purity CO_2) over geologic time will automatically contain 100% of the aqueous fluid mixtures with lower interfacial tensions such as CO_2 in brine or CO_2 and H_2S mixtures in brine. It must be recognized that this leakage mechanism is rock-, pressure-, temperature- and fluid-dependent, and the variability of CO_2–brine IFT pressures for brines of differing salinity is well documented (Li and others, 2005; Zhaowen and others, 2005).

CO_2–brine IFT decreases with increasing pressure, while increasing temperature and brine salinity have the opposite effect. Specific data on H_2S–water and CO_2–H_2S IFT have recently been reported (Shah and others, 2008) in which the H_2S–brine system acts in a similar manner but at a much lower capillary entry pressure than the CO_2–brine solution. The H_2S–water IFT is 30% to 40% lower than that of the CO_2–water IFT. However, for both systems, the IFT is much lower than the in situ hydrocarbon IFT that originally provided the trapping mechanism for the hydrocarbons against the cap rock layer. Thus, additional laboratory IFT studies are suggested to further investigate aqueous H_2S and aqueous CO_2–H_2S mixtures.

In conclusion, these studies suggest that containment of acid gas in a geological reservoir setting may be affected by the capillary properties of the acid gas–brine solution in relation to the capillary pore entry pressure of the brine-saturated cap rock system. In particular, the studies suggest that the maximum reservoir pressure to avoid acid gas imbibition into the cap rock may be lower than current pressure limits derived from mechanical stress testing. The designated maximum operating reservoir pressure will be pool-specific. If a lower maximum reservoir pressure limit is necessary, the estimates for storage capacity in each reservoir will require review. The impact on the gas miscibility with the reservoir oil and the EOR project will also need to be reviewed.

Wellbore Integrity and Leakage Potential

Wellbores constitute a critical element with regard to the disposal and storage of acid gas and CO_2 because they may provide a leakage pathway. It is not possible to determine the “exact” state of all wellbores; consequently, the approach that was used in the Zama project, and which is recommended for use in areas with a large number of existing wellbores, was to combine both “real” field data and analytical or numerical simulations to quantify processes associated with the hydraulic integrity of the wells. Statistical well geometry and performance data within the Zama field and surrounding regions were compiled from available databases. A database of project-specific well data was constructed from detailed review and synthesis of available well file information. In a limited number of cases, data were available from old wellbores where cement samples had been taken to evaluate their stability in the long term. Based on this information, probabilistic assessments of wellbore integrity issues under the conditions of acid gas and CO_2 injection and long-term buoyancy-driven forces were evaluated.

For the Zama project, a review of the integrity of the casing cement, and completion of the new acid gas EOR/CCS wells drilled into the F Pool as part of the project was conducted and led to the following conclusions:

- Overall Well Assessment – The integrity of the current wells is good, with no leaks to date and a minimal to moderate probability of seepage or leaks, with the possible exception of the original 1967 well completion. This well was recognized as having the greatest chance of seepage early in Phase II of the project based on its age and cement quality, as well as the fact that it is plugged back to the Slave Point FFF completion with a series of internal packer/bridge plugs that are capped with cement. As a result, this well was proposed as the site for a gas-soluble tracer study.

- Casing/Cement Integrity Assessment – No casing inspection logs were located for any of the four wells in the F Pool. Nevertheless, there is minimal potential for leakage from the three wells completed since 2004; however, the original well, which was drilled in 1967, has the potential to allow leakage because of a very low production casing cement top. The other three wells have surface casing cemented at or near surface and should have minimal chance of a surface casing vent flow or shallow seepage to groundwater.

- Completion Integrity Assessment – The review of the tubing strings and downhole completion equipment utilized in the F Pool wells revealed that all of the wells have standard L-80 tubing above the packers and should be monitored for corrosion. Typically, this is done by pressure testing the annulus to ensure that there is no communication with the tubing. The three newest wells utilize corrosion-resistant Incoloy packers, profiles, and on–off tools from the packer down, along with SM-222 coating of the tubing joints below the packer. Two of the production strings also utilize complex multiple packer assemblies to allow for tracking of the EOR flood interface. This has the potential to provide good data regarding the sweep and recovery efficiency but also carries some risk due to the numerous potential leak paths in the completions.

Tracer and Pressure-Monitoring Programs

One of the primary concerns with any CO_2 or acid gas injection project is leakage of the injected gas from the target reservoir through the cap rock and into an overlying zone of high porosity and permeability. At Zama, this concern was addressed by using an existing well that is completed in the Slave Point FFF Pool, which lies directly over the Keg River F Pool pinnacle reef, as a monitoring well. Specifically, the Slave Point FFF Pool well was used to collect Slave Point Formation fluid samples that were analyzed for a tracer that was injected into the Keg River F Pool. The monitoring well was also used to monitor for changes in Slave Point FFF Pool pressure that might be indicative of acid gas leakage into the Slave Point Formation. The concept for the pressure-monitoring program was that close examination of historical pressure data from the Slave Point FFF Pool well and comparison of those data with pressure data collected during the Zama acid gas EOR and CCS project could provide insight regarding the potential use of pressure data as a low-cost monitoring technique.

A gas-soluble, fluorocarbon-based chemical tracer compound (5.5 kg of Core Labs IGT-1100) was injected into the Keg River F Pool in February 2008. Other naturally occurring compounds, such as CO_2 or H_2S with unique isotopic fingerprints, were considered and, in some geological settings, may be appropriate and more cost-effective. However, the presence of large amounts of naturally occurring CO_2 and H_2S throughout the Devonian-age rocks of northwestern Alberta, including the Keg River and Slave Point Formations, combined with the complicated history of acid gas production and disposal in the Zama area led the technical team to recommend the use of a proprietary synthetic fluorocarbon-based tracer compound. Initial gas sampling was performed on the Slave Point Pool in April 2008. A further gas-sampling operation was conducted on December 20, 2008. No tracer has been detected in any of the gas samples to date, although the scheduled mid-2009 samples have not yet been collected as a result of personnel and budget restrictions. The on-site tracer-sampling program is complicated by the fact that the Slave Point well "watered out" and no longer flows gas. Sampling from a flowing well would be much simpler and less expensive.

The pressure-monitoring program at Zama consisted of monitoring of the reservoir pressures of both the Keg River F Pool at 2175 psi (±15,000 kPa) and the Slave Point FFF Pool at roughly 870 psi (3000 kPa). These pressures were monitored on the same 6-month schedule as the collection of the tracer samples based on the premise that if the wellbore allows leakage, it will eventually be detected by an increase in the lower-pressure Slave Point completion. The last two Slave Point FFF pressures indicate a small 29-psi (200-kPa) increase in pressure (Figure 14). At this point, it cannot be determined if this is a result of two different gauge readings, water influx, an increase of pressure due to the arrival of a pressure front being generated by the Keg River F Pool injection, or seepage of acid gas from the Keg River F Pool into the Slave Point FFF Pool. More pressure data are required before the source of any pressure change can be attributed to any of these or any other causes.

Appendix B shows the techniques employed over the course of the project to monitor the effects of acid gas injection at the Zama Field demonstration site. The baseline state of each of these parameters was determined as described above.

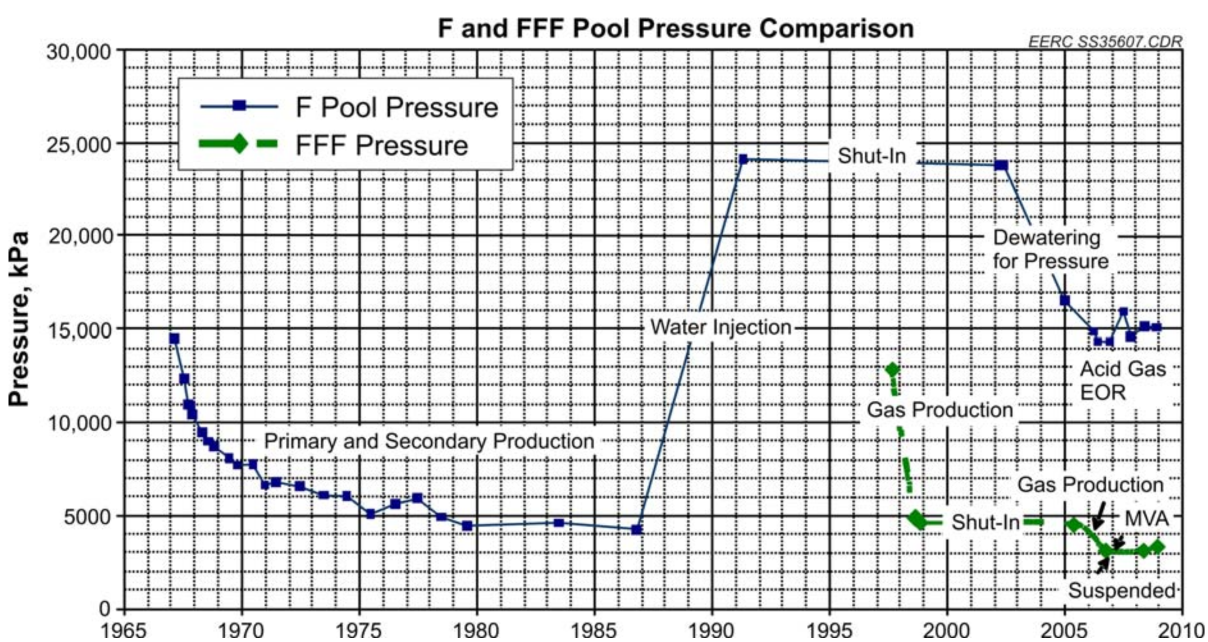

Figure 14. Pressure-monitoring MVA program.

INJECTION PROGRAM

The injection program for the Zama EOR and CCS project was designed, implemented, and operated by Apache Canada according to regulatory guidelines established by the Alberta ERCB. The purpose of the injection program is to 1) cost-effectively capture, transport, and inject acid gas from the Zama gas-processing plant into the Zama F Pool reservoir; 2) facilitate the production of incremental oil from the F Pool reservoir; and 3) support the documentation of effective CO_2 storage in the F Pool. Over the course of the Zama EOR and CCS project, a variety of site-specific design and operational challenges were identified and addressed to varying degrees of success. A detailed discussion of the site-specific issues is beyond the scope of this report. Rather, as an RTIP, this report will focus on the components of the Zama Keg River F Pool acid gas injection program that may be more broadly applicable across North America. Key aspects of the Zama injection program that this RTIP will address include the capture and infrastructure elements of the project, well preparation and maintenance activities, acid gas injection and EOR operations, and determination of CO_2 storage capacity.

Capture and Infrastructure at Zama

The Zama gas-processing plant handles all of the production taken from the field and prepares it for sales to the market. Originally, the solution gas produced from Keg River oil pools contained approximately 5% CO_2 and 3% H_2S. The Zama gas-processing plant also processes nonassociated gas from the field, which contains approximately 13% H_2S and 8% CO_2. Finally, an amine-based acid gas removal (AGR) system generates an effluent stream that is approximately 4% methane, 66% CO_2, and 30% H_2S. The effluent acid gas exits the AGR system in the gas plant at essentially atmospheric pressure. Using a corrosion-resistant compressor, the acid gas is compressed to the appropriate pressure for injection. Additional acid gas is stripped from oil produced through EOR activities at a separator tank, compressed, and commingled with the previously discussed stream. It is this gas stream that is injected as the acid gas miscible flood solvent. The acid gas stream is transported from the gas plant to the injection site through a pipeline made of corrosion-resistant steel.

It is worth noting that several site-specific operational challenges were identified over the course of operating the acid gas EOR/CCS facility. While a detailed description and discussion of these issues is beyond the scope of this report, of particular importance to the operation of the Zama injection project were:

1. Optimization of perforation zones within each pinnacle reef.

2. Optimization of gas injection rates.

3. Plugging/freezing of flow lines and wells due to hydrates, wax, and asphaltene precipitation (wax-stabilized hydrates).

Any or all of these items may represent operating challenges to any EOR/CCS operating facility and have the potential to result in increased engineering work as well as increased operating costs. Optimization of the perforation zones and gas injection rates will be entirely site-specific, and the degree of difficulty in determining the optimal conditions will be largely dependent on the degree of heterogeneity within the target reservoir. The plugging/freezing issues that were encountered over the course of the Zama project may be an issue wherever a combination of oil characteristics and cold climate conditions may be found. Figure 15 shows a picture of a plugged flow line. If this occurs, the plug can rarely be cleared without excavation of the flow line, as shown. At Zama, Apache Canada has had to insulate lines and use a combination of heat and chemicals to economically resolve these problems. However, it is important to note that, as was the case at Zama, none of these challenges are entirely new to the oil and gas industry and, given time and thoughtful consideration, all of them are manageable and do not threaten the commercial use of acid gas injection for EOR or as a viable CCS strategy.

Well Preparation and Maintenance

CCS project operators and related stakeholders generally agree that the ability of new and existing wellbores to reliably contain CO_2 is of upmost importance. The main reasons for this include validation of storage volumes and related CO_2 storage credits, minimizing MVA operations, and to gain public confidence. The collective documentation of the required design features for new and old wells is commonly termed a basis of design (BoD). The BoD establishes a clear understanding of the required well functional and performance specifications, life span, injection fluid and corrosion specifications, reservoir characterization, completion configuration, corrosion and integrity-monitoring plan, barrier and safety systems, and well-operating and maintenance schedule. Some of the key considerations that went into the development of the BoD are discussed below.

The basis of oil and gas industry well design for CO_2 injection and storage stems from long-established practices developed to inject associated CO_2, H_2S, acid gas, saline brine, and waste fluids within a wide variety of reservoirs since the mid-1900s. Among these fluids, acid gas (H_2S + CO_2 + SO_2) has the highest potential for wellbore corrosion and health, safety, and environmental (HSE) damage as H_2S can cause sudden deadly respiratory arrest. Dry CO_2 alone

Figure 15. Operation to clear a plugged flowline.

is minimally corrosive, but wet CO_2 (mixed with saline brine) can be very corrosive and represents a significant challenge to petroleum industry standards. Fortunately, preventing and mitigating leakage of petrochemical and petroleum fluids is a long-standing objective of the oil and gas industry.

Despite the challenges presented above, the injection of CO_2 and acid gas is a relatively common practice that has been used for decades in North America. North American CO_2 injection has roots within the Permian Basin of West Texas, with the use of CO_2 for EOR. The first known project was started by Chevron in Scurry County, Texas, in January 1972. Since then, CO_2-based EOR has been conducted on a large scale throughout the world, including several large oil fields in West Texas, Saskatchewan, and Alberta. In the Western Canadian Sedimentary Basin, acid gas injection experience is similar to that of CO_2. Some moderately sour gas injection has been under way since the late 1970s as part of pressure maintenance schemes for selected oil fields. In 1989, the injection of acid gas for the purpose of outright disposal began when Chevron installed the first acid gas compression and injection operation at Acheson, Alberta (Royan and Wichert, 1997). This industry activity has led to the current status whereby the materials and procedures to drill and complete a well for the production or injection of CO_2, H_2S, and/or acid gas mixtures are very well defined by regulations, standards, and IRPs.

The selection of corrosion-resistant materials for well completions is critical to the long-term operation and maintenance of an acid gas EOR and/or CCS project. Manufacturer-supplied guides can provide useful insight to the selection of corrosion-resistant alloy (CRA) steel based on the exposure to CO_2 and H_2S at different temperatures. While guides such as this are useful, it is important to note that economics and practical considerations must also be factored into the final design. For instance, exclusive use of a simplified manufacturer's guide would lead one to assume that there should be considerable use of high-cost chrome- and nickel-based alloys. However, as a result of the significant incremental costs for CRA pipe, most CO_2 and acid gas applications have turned to the use of low-alloy carbon steel protected by coatings or linings for casing and tubing applications. In some circumstances, a well design will utilize one or two joints of CRA casing within critical wellbore sections such as casing over the reservoir zone where repeated reseating of a production packer may be required. Smaller equipment items such as packers, flow control devices, and subsurface safety valves are also often constructed of nickel-based alloys as it is more difficult to protect all of the wetted and working surfaces of these items with coatings. This approach has been applied successfully to the design of acid gas injection and sour gas production wells throughout North America as well as at Zama.

The use of corrosion-resistant cements is also a critical component to maintaining wellbore integrity. On balance, the most recent work strongly indicates that properly designed portland-based oil well cements are very CO_2-resistant (Crow and others, 2008). Duguid (2008) provides a good summary of recent experimental work and concludes that a well-cemented well with good zonal isolation will be safe for 30,000 to 700,000 years. These publications consistently show that CO_2 and brine mixtures do change the texture and mineralogy of portland oil well cements, but that the changes do not significantly reduce the hydraulic seal afforded by the cement sheath.

Well preparation activities at Zama included conducting a variety of tests to determine the integrity of the existing F Pool wells. The integrity of new or old wells is easily verified with modern downhole logging tools, including mechanical caliper tools, electromagnetic tools, and acoustic resonance tools. An example of the types of data used to evaluate wellbore integrity is shown in Figure 16. Any existing field or area proposed for CO_2 storage must include an evaluation of the ages and wellbore integrity of existing wells as part of the local risk evaluation. Even very old oil field wells have been shown to provide reliable well integrity for CO_2 injection and storage.

Acid Gas Injection

The injection of acid gas into the Zama Keg River F Pool pinnacle reef was initiated in December 2006. Injection continued well into 2009, with some interruption for well maintenance, and Apache Canada plans call for continued injection beyond 2010. Some of the more important statistics for the period of operation between December 2006 and May 2009 are summarized below.

During the 30 months between December 2006 and August 2009, approximately 2500 metric tons/month of acid gas was injected into the Keg River F Pool (1850 metric tons of CO_2 and 650 metric tons of H_2S). The injection was at an average depth of 1455 m, which was the top of the Keg River Pool pinnacle reef. These injection rates were designed to maintain the prescribed miscible pressure range and maintain a stable displacement. The average daily acid gas injection rate throughout 2009 has been approximately 1.4 MMscf ($50 \times 10^3 m^3/d$). Through August 30, 2009, the cumulative amount of gas injected into the F Pool was 1) 40,160 metric tons of acid gas, 2) 29,720 metric tons of CO_2, and 3) 9640 metric tons of H_2S. After adjustment for the reproduced mass, the net stored CO_2 and H_2S in the F Pool is 16,050 and 5807 metric tons, respectively.

The acid gas injection and production histories for the period of December 2006 through May 2009 are shown in Figures 17 and 18. During this 30-month period, injection rates have varied to either maintain pressure in the F Pool or conduct well maintenance activities. The long-term average injection rate is roughly 2500 metric tons per month. Daily averages were approximately 60.8 metric tons of CO_2 and 21 metric tons of H_2S.

Over the entire 4-year life of the F Pool project (December 2006 to December 2010), between 40,000 and 60,000 metric tons of acid gas will be injected. Prior to decommissioning at the end of the EOR program, some of the stored acid gas volume may be produced back for injection into one or more of the other EOR/storage pools. This ability to “bank” and reuse the acid gas is seen as a distinct advantage for supplying injection gas to multiple EOR/storage pools in the area. However, the net volume of acid gas expected to be permanently retained in the F Pool upon completion of the EOR project (approximately 2019) is in excess of 40,000 metric tons. Figure 19 presents the cumulative injected and stored F Pool mass and volumes to May 30, 2009. Figure 20 details the net stored CO_2 mass.

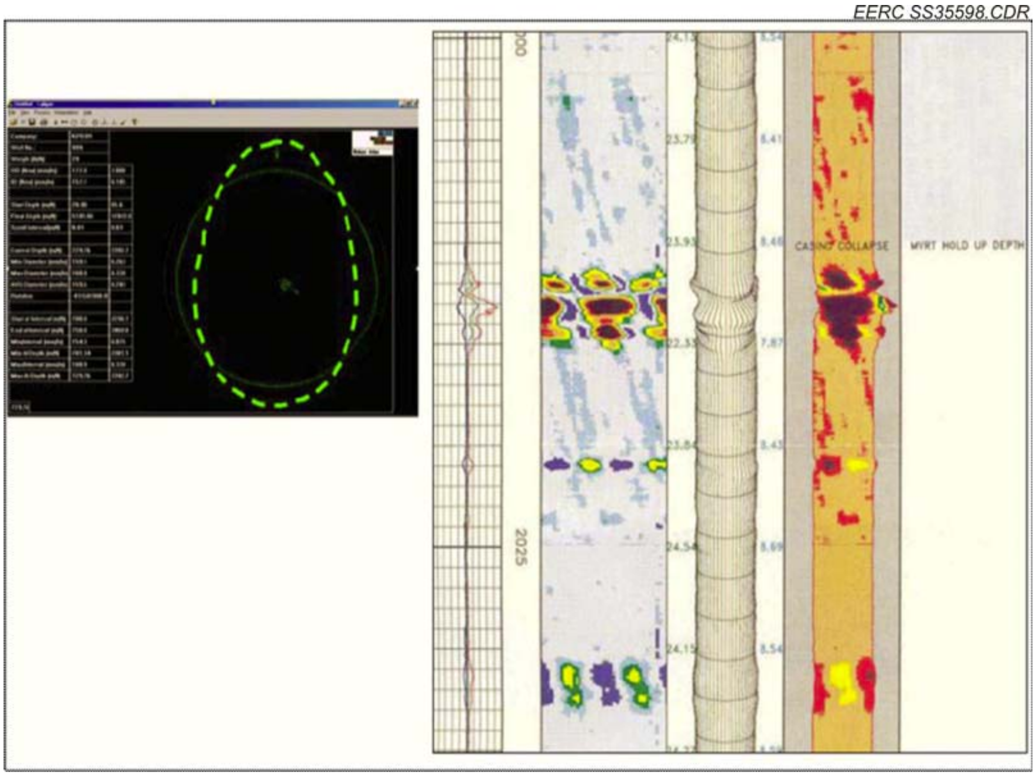

Figure 16. Example of raw logging data and interpretation showing casing deformation (courtesy of Baker Hughes).

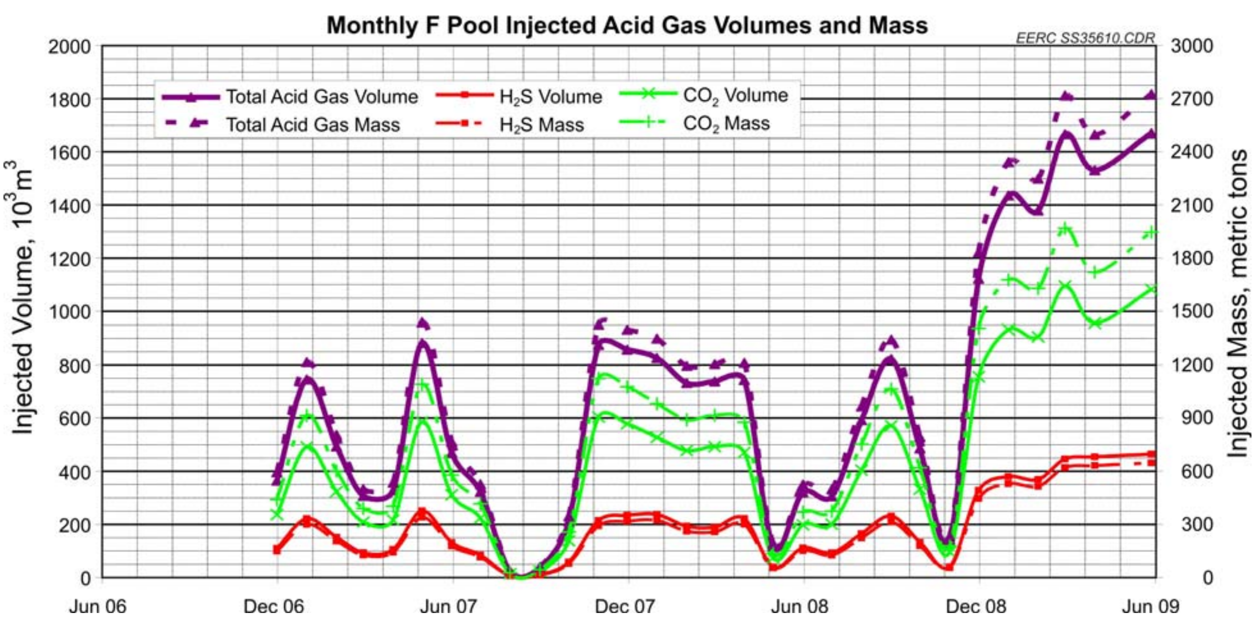

Figure 17. Monthly F Pool injection history – volume and mass.

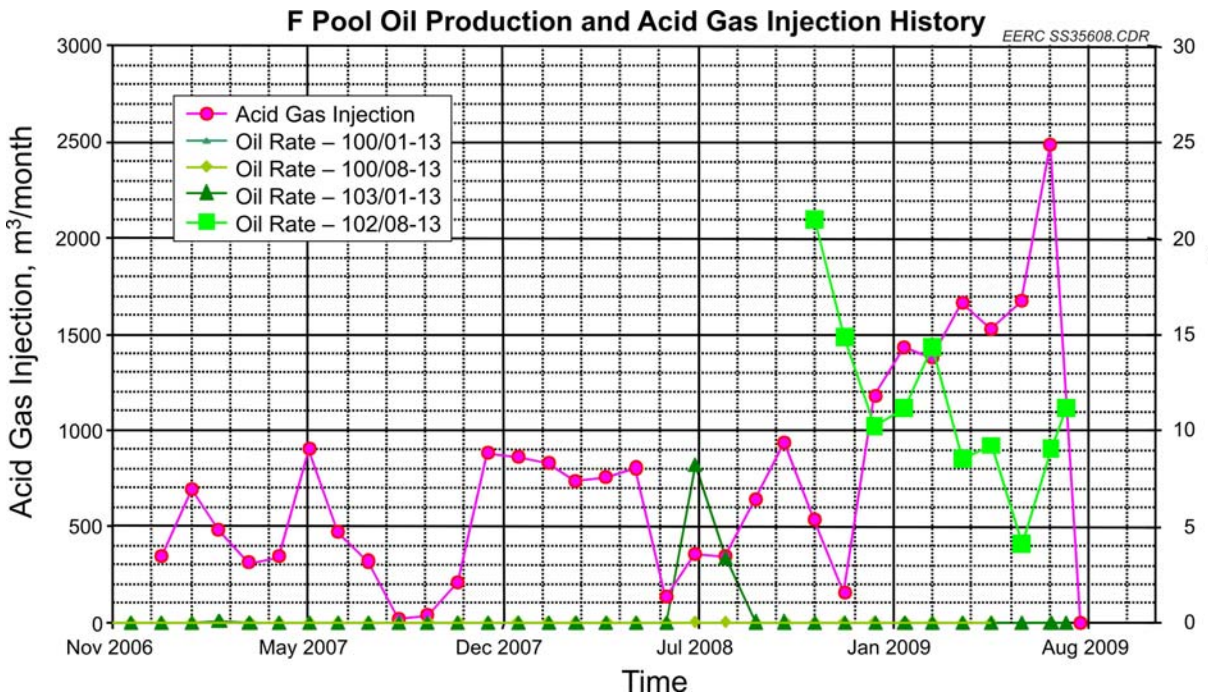

Figure 18. Keg River F Pool oil production and acid gas injection profiles.

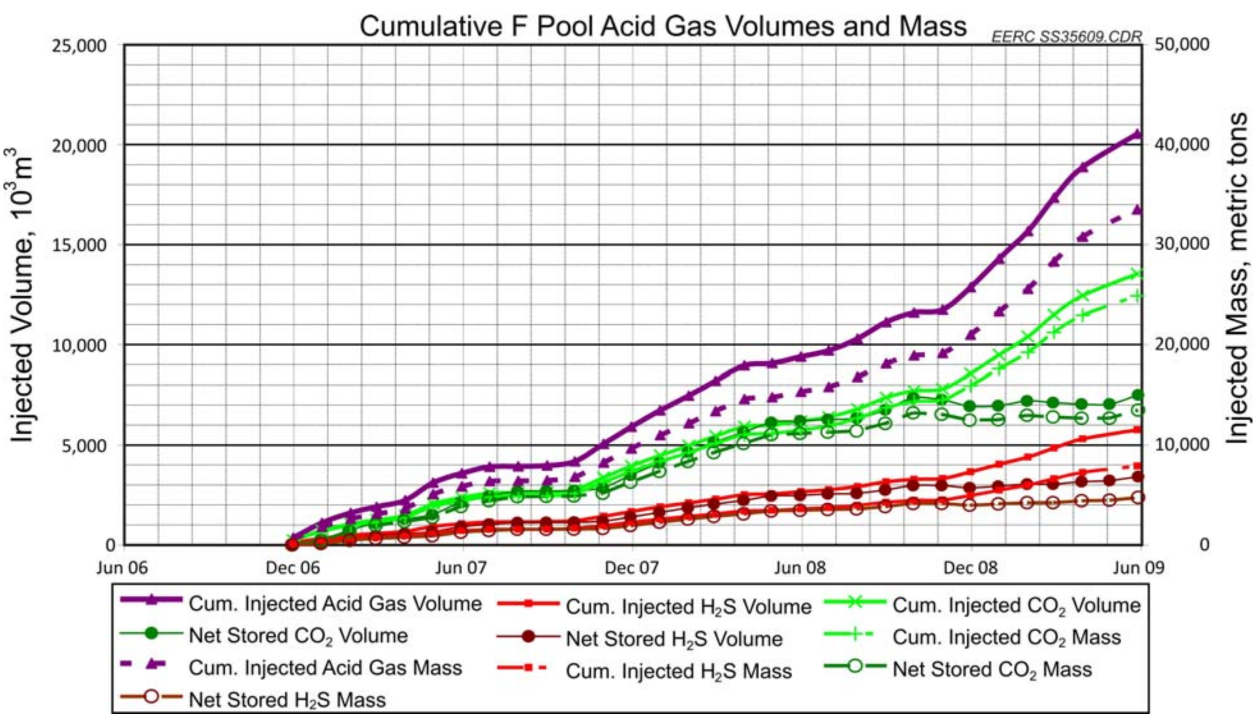

Figure 19. Cumulative F Pool injected volumes and mass of acid gas.

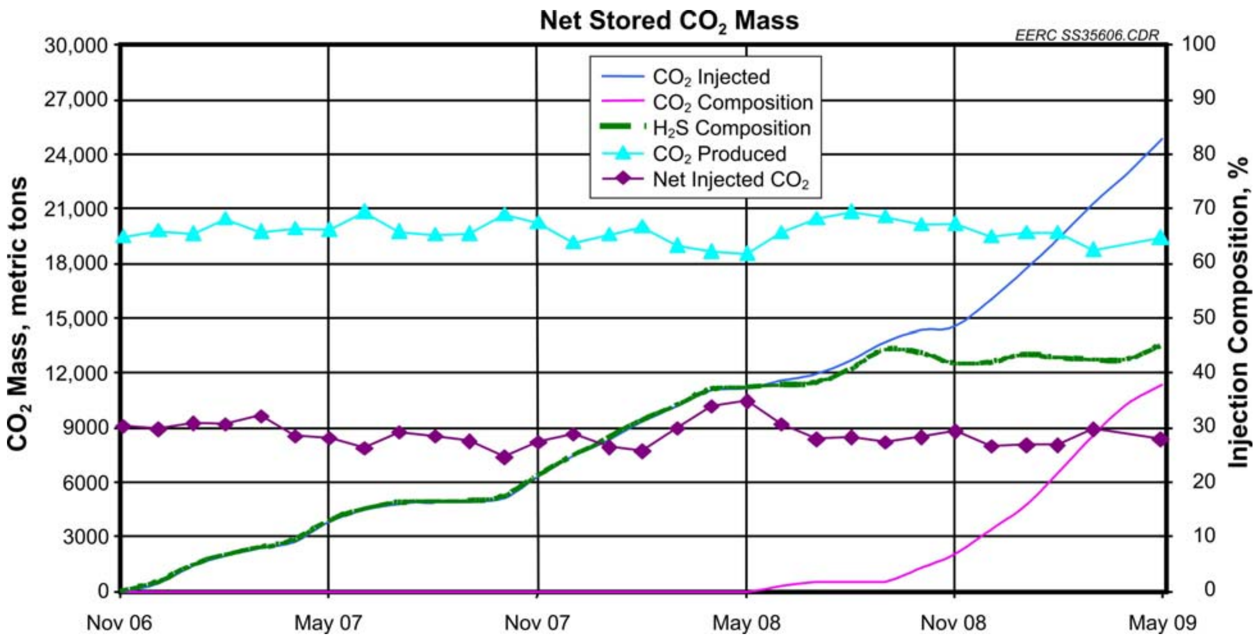

Figure 20. F Pool–mass of CO_2 stored.

EOR Operations

As part of Apache Canada's plans to conduct a new phase of oil recovery operations in the Zama oil field, a new production well was drilled into the F Pool in September 2004. The well, referred to as Production Well 1, was placed in production in August 2005. The well was perforated low in the formation and, unfortunately, was a poor producer, with a cumulative oil production of only about 75 m^3 (470 bbls) between August 2005 and May 2006. In order to prepare the F Pool reservoir for acid gas injection and EOR, this well was then utilized to draw water from the lower portion of the pinnacle to lower the average reservoir pressure down to the original ERCB-approved range. This objective was accomplished by November 2006, but injection was not started until December 2006 when the Zama Keg River F Pool became the third pool in the Zama oil field to be placed on acid gas EOR.

By December 2007, acid gas injection had been conducted for a year but oil production had not yet begun. Apache Canada reconsidered the production strategy in the F Pool, resulting in plans to conduct a workover on Production Well 1 and to drill an entirely new well, Production Well 2, into the F Pool. A workover of Production Well 1 was completed in June 2008, and Production Well 2, the fourth and newest well in the F Pool, was drilled in August 2008. Some additional oil was produced as a result of these actions. Specifically, the workover of Production Well 1 yielded 350 m^3 (2200 bbl) of oil, with the cumulative oil production from the beginning of EOR totaling roughly 430 m^3 (2700 bbl). The newest well in the pool, with only the upper set of perforations open to production, produced 8900 bbl of oil during the first 3 months. The configuration of the final F Pool EOR scheme is shown in Figure 21.

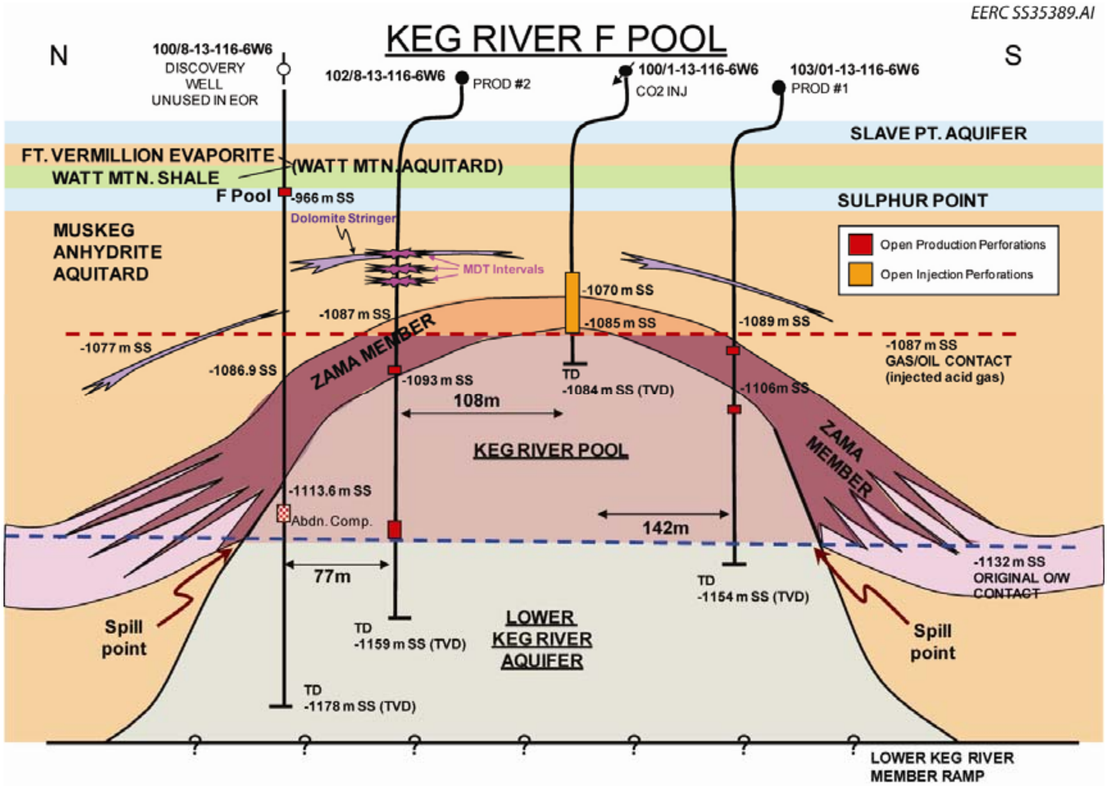

Figure 21. Zama Keg River F Pool EOR scheme as of May 2009.

Historically, the F Pool had declined in production to an uneconomical rate. Through a modeling study conducted by the University of Regina in 2005, it was determined that injection of acid gas for EOR could revive this pinnacle and return it to an economically viable producer. As of June 2009, there has been minimal incremental oil production from the F Pool as a result of the acid gas injection, as it appears the project is still in the dewatering and displacement phase. Acid gas injection at the top of the structure is being balanced by high water-cut production from the bottom of the structure to develop and maintain stability of the miscible sweep. Water is being displaced in a gravity-stable, top-down manner. While the oil bank has not yet reached the main production perforations in Production Well 1, it has reached the producing interval in Production Well 2.

Prior to the EOR project, the OOIP in the Keg River F Pool was estimated to be approximately 3914 Mbbl. It should be noted that revised estimates using updated reservoir models now estimate the total volume to be approximately 5000 Mbbl. The volume of oil recovered during the three stages of oil recovery are as follows: 1073 Mbbl (27%) were recovered during primary production, 35 Mbbl (1%) during secondary production (water flooding), and an anticipated 588 Mbbl (15%) to be produced during tertiary recovery associated with acid gas injection. Roughly 57% (2218 Mbbl) of the OOIP is currently estimated to be unrecoverable by current methods (Figure 22).

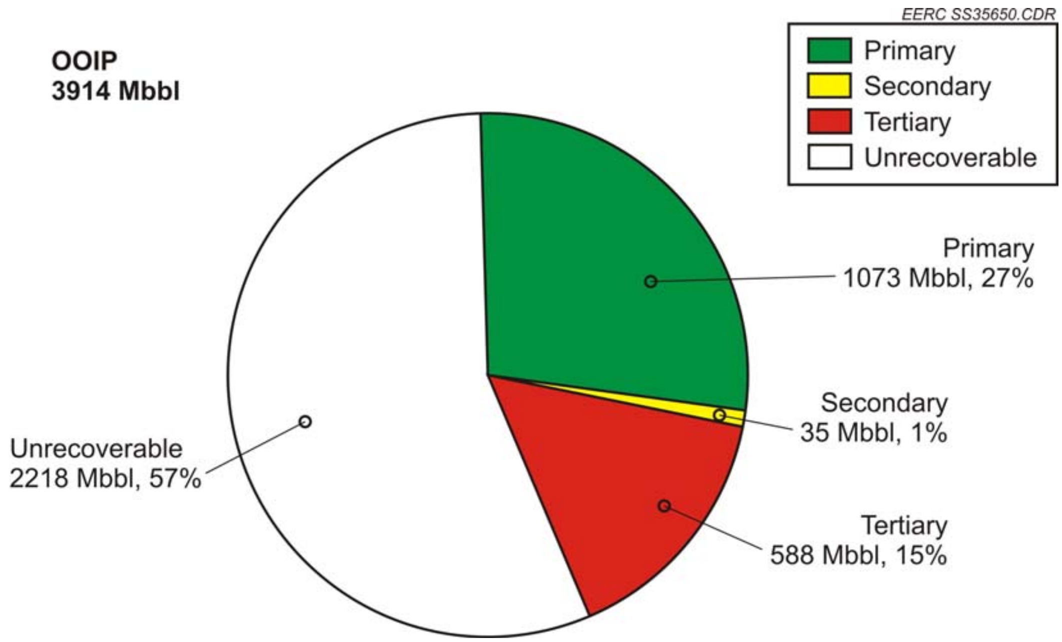

Figure 22. Keg River F Pool volumetric estimation of OOIP and subsequent production prediction.

Determination of CO_2 Storage Capacity

Through August 30, 2009, the cumulative amount of gas injected into the F Pool was 1) 40,160 metric tons of acid gas; 2) 29,720 metric tons of CO_2; and 3) 9640 metric tons of H_2S. After adjustment for the reproduced mass, the net stored CO_2 and H_2S in the F Pool is 16,050 and 5807 metric tons, respectively.

As described above, it is anticipated that over the entire 4-year life of the F Pool project (December 2006 to December 2010), between 40,000 and 60,000 metric tons of acid gas will be injected. It is also anticipated that some of the stored acid gas volume may be produced back to surface for injection into one or more of the other EOR/storage pools that exist in the Zama oil field. This ability to "bank" and reuse the acid gas is seen as possibly being necessary for supplying injection gas to multiple EOR/storage pools in the area, as the output of acid gas from the Zama gas plant is not considered to be large enough to meet all of Apache Canada's EOR goals for the Zama oil field. However, the net volume of acid gas expected to be permanently retained in the F Pool upon completion of the EOR project is in excess of 40,000 metric tons. While this value is not of the scale of many commercial projects, it should be noted that there are currently more than 800 pinnacles of this type producing from the Zama Field. When taking these additional pinnacles into consideration, the field becomes a significant site for CCS activities.

New reservoir-modeling efforts were conducted to estimate the ultimate CO_2 storage capacity of the Zama Keg River F Pool pinnacle reef and predict the fate of the injected acid gas. Specifically, conventional material balance models of the reservoir had to be updated with compositional pressure–volume–temperature to allow for evaluating original black oil fluids (oil, gas, water) along with the acid gas. However, models with and without this upgrade provided successful pressure history matches by including a very weak aquifer that only has a small impact during the shut-in period. This observation was consistent with the level of pressurization that occurred in the F Pool after primary oil recovery operations and water injection activities ceased in 1992 and also supports the conclusion that there is only a minimal chance that the acid gas will be displaced under the spill point at the base of the F Pool.

Furthermore, it was concluded that the reservoir material balance provides an acceptable reproduction of the Keg River pool production history. Specifically, the compositional model allows for reliable predictions of pool performance and response and, based on the allowable operating pressure, validates the F Pool volume and EOR potential and establishes available acid gas storage volumes. It also validates that the F Pool has minimal connectivity to the underlying Lower Keg River Aquifer, indicating that the pool will pressure up prior to forcing any significant volume of acid gas below the pinnacle spill points.

KEY OBSERVATIONS, CHALLENGES, AND LESSONS LEARNED

As described above, the PCOR Partnership's Phase II activities at Zama combined a wealth of historical information with newly generated laboratory- and field-based data to develop a broad range of previously unavailable insights regarding the injection of acid gas for EOR and CCS. These insights can provide stakeholders and planners of future similar projects with the ability to make informed decisions for a variety of design elements. Project-critical technical areas for which information was compiled for this RTIP include baseline geological and hydrogeological characterization, wellbore integrity issues, determination and implications of geomechanical properties of reservoir and seal rocks, expectations for geochemical interactions, prediction of near- and long-term effects and fate of the injected gases, and design and operation of wells and surface infrastructure in the presence of high concentrations of acid gas. Some of the key observations, challenges, and lessons learned over the course of the Zama acid gas injection project are briefly summarized below.

Suitability of Pinnacle Reefs for Acid Gas Injection and Long-Term CCS

Based on the available data, the geological studies concluded that the injection of acid gas into the pinnacle reefs of the Zama Keg River Formation is a safe operation. The acid gas will be confined to the injection horizon by the reef structures that originally trapped the oil and gas. There is minimal potential for acid gas leakage through faults and fractures in the Zama area or for acid gas migration to shallower strata, potable groundwater, or to the surface as a result of flow through naturally occurring permeability streaks or flow paths.

The strength of the reservoir and cap rock formations, as determined by the geomechanical and geochemical evaluations, combined with the closed architecture of the pinnacle structure and the very conservative maximum operating pressures leave little possibility of lateral migration outside of the reef structures. Further, the results of the regional hydrogeological study indicates that any potential dispersion beyond the individual pinnacle spill points into the regional aquifer would still result in storage occurring before the plume had traveled a significant distance, e.g., the maximum velocity of the formation water is sufficiently slow that it would take as mush as 800,000 years for a fluid molecule to reach a Keg River Formation outcrop.

When combined with data from laboratory pore entry mercury injection pressure tests and mechanical stress testing on similar area cores, as well as log analyses and drilling reports, there is strong evidence that the thick (200 ft [60 m] to 300 ft [90 m]) Muskeg Formation dolomite/anhydrite sequences provide a competent, dense, and essentially impermeable cap rock above the Keg River pinnacles. These data suggest that the F Pool pinnacle integrity far exceeds the current ERCB EOR pressure limit, and it could be proposed that following the completion of the EOR recovery, additional CO_2 and/or acid gas volumes could be stored within this pinnacle by increasing the allowable storage pressure beyond the original reservoir pressure.

There are currently known to be over 800 pinnacle reefs in the Zama subbasin of the Western Canadian Sedimentary Basin. There are also known to be hundreds of similar pinnacle reefs that occur in the Williston Basin, Michigan Basin, and Illinois Basin, just to name a few. The geological and hydrogeological studies conducted at Zama provide supporting documentation that pinnacle reefs can be suitable and even excellent sites for CCS.

Relative Mobility and Fate of CO_2 and H_2S Within Carbonate Reservoirs

One set of questions that were identified early in the Zama project was whether or not the primary constituents of the acid gas stream would undergo separation within the reservoir, and if it did occur, what the magnitude and timing of that separation would be. The results of geochemical modeling conducted that used the geochemical and mineralogical properties of the F Pool reservoir indicated that the leading edge of the acid gas plume will become enriched in CO_2. This observation was in agreement with the results of field- and laboratory-based analytical activities and other modeling efforts. The enrichment is due, at least in part, to the preferential absorption of H_2S into the aqueous phase. However, in the presence of reactive iron-bearing minerals, other processes can lead to the separation of the two gases. As the acid gas plume reacts with the carbonate minerals, significant amounts of iron and bicarbonate are added to the water. This iron rapidly precipitates as an iron sulfide when H_2S is present in the gas phase. The iron sulfide precipitation produces a significant amount of acid; this acid drives much of the bicarbonate out of aqueous solution, leading to further CO_2 enrichment in the gas plume.

Additional transport studies suggest that containment of the acid gas in a geological reservoir may be affected by the capillary properties of the acid gas–brine solution in relation to the capillary pore entry pressure of the brine-saturated cap rock system. In particular, the studies suggest that the maximum reservoir pressure limitation to avoid acid gas leakage through, or imbibition into, the cap rock may be lower than current pressure limits derived from mechanical stress testing. The designated maximum operating reservoir pressure will be pool-specific. If a lower maximum reservoir pressure limit is necessary, the estimates for storage capacity in each reservoir will require review. The impact on the gas miscibility with the reservoir oil and the EOR project will also need to be reviewed.

The results of the acid gas mobility and fate investigations conducted as part of the Zama project may be directly applicable not only to the hundreds of similar pinnacles in the Zama subbasin, but to acid gas injection projects in carbonate rock formations in general.

Effects of Acid Gas on Wellbores and Surface Infrastructure

The selection of corrosion-resistant materials for well completions and surface infrastructure is critical to the long-term operation and maintenance of an acid gas EOR and/or CCS project. Because of the higher costs of such materials, the judicious application of corrosion-resistant materials in the design of wells and surface facilities is required to maintain the proper balance of performance versus cost. For instance, as a result of the significant incremental costs for CRA pipe, most CO_2 and acid gas applications have effectively used low-alloy carbon steel protected by coatings or linings for casing and tubing applications. In some circumstances, it may also be appropriate to utilize one or two joints of CRA casing within critical wellbore sections rather than throughout the entire length of the well. Smaller equipment items such as packers, flow control devices, and subsurface safety valves are also often constructed of nickel-based alloys, as it is more difficult to protect all of the wetted and working surfaces of these items with coatings. This approach has been applied successfully to the design of acid gas injection and sour gas production wells at Zama and, in most cases, can be broadly applied to similar injection schemes wherever they may be planned.

The use of corrosion-resistant cements is also a critical component to maintaining wellbore integrity. In general, recent literature suggests that properly designed portland-based oil well cements are very CO_2 resistant. In fact, the results of experimental work presented by Duguid conclude that a properly cemented well with good zonal isolation will be safe for 30,000 to 700,000 years. The literature also consistently shows that while CO_2 and brine mixtures do change the texture and mineralogy of portland cements used in oil wells, those changes do not significantly reduce the hydraulic seal afforded by the cement sheath.

A review of the integrity of the casing cement and completion of the acid gas EOR/CCS wells in the F Pool indicated that the integrity of the current wells is good. With respect to the infrastructure at Zama, some site-specific challenges were encountered, most notably the plugging of flowlines with asphaltines and waxes, particularly during the winter months. These problems were successfully addressed by Apache Canada through the combined use of heated and/or insulated flowlines and the introduction of chemical additives to prevent the coagulation of those materials. It is important to note that none of the operational challenges at Zama are new to the oil and gas industry and, given time and thoughtful consideration, all of them are manageable and should not threaten the commercial use of acid gas injection for EOR or as a viable CCS strategy.

The Use of Pressure Data and Tracers to Detect Leakage

One of the goals of the Zama project was to minimize any disruption to normal commercial oil field operations. One way to achieve this goal was to look for ways to maximize the use of data sets that are routinely gathered over the course of oil field operations. Pressure data, both from the preinjection history of the F-Pool and from the injection phase of the project, were identified as one possible way of identifying the leakage of acid gas from the pinnacle reef into an overlying formation. Another technique that would cause minimal disruption to normal operations was to do a one-time injection of a unique tracer compound into the acid gas stream early on during the injection phase and then monitor for that tracer in the various production and monitoring wells as part of periodic sampling and analysis events. In the case of the Zama F Pool, an existing gas production well that was completed into the overlying Slave Point Formation was selected to serve as a monitoring well for both the pressure measurements and tracer analyses.

With respect to the tracer monitoring, a gas-soluble chemical tracer compound (5.5 kg of Core Labs IGT-1100) was injected into the Keg River F Pool in February 2008. The collection and analysis of fluid samples from the Slave Point FFF Pool for the tracer was conducted on a 6-month schedule. No tracer has been detected in any of the gas samples to date.

Historical and current pressure data were gathered for both the Keg River F Pool and the overlying Slave Point FFF Pool. During the Zama injection project, initial pressure testing was performed on the Slave Point FFF Pool in April 2008. A further pressure survey and gas-sampling operation was conducted on December 20, 2008. The historical data combined with the new data allowed for a comparison of the Keg River F Pool and Slave Point FFF pressure histories and indicate a small 29-psi (200-kPa) increase in pressure in the last two Slave Point FFF Pool measurements. At this point, it cannot be determined if this is a result of two different gauge readings, water influx, or an increase of pressure due to seepage. More pressure data are required before the source of any pressure change can be attributed to any of these or any other causes.

Generally speaking, the results of the tracer and pressure-monitoring activities at Zama indicate that both techniques hold considerable promise for application as useful, noninvasive, cost-effective elements of an MVA plan.

Nontraditional Economic Components

One of the primary goals of the Zama project, especially with respect to MVA, was to establish a basis for the creation and eventual monetization of carbon credits associated with the CCS component of the project. The MVA activities conducted at Zama were designed to yield data that would demonstrate 1) the containment of the injected CO_2, 2) the mass of CO_2 stored, and 3) the long-term safety of the project with respect to human health and the environment. The MVA data generated over the course of the Zama project have certainly provided a technically robust, detailed accounting of all three of these aspects. Unfortunately, robust carbon credit-trading markets for credits associated with geological storage of CO_2 have been very slow to develop and, to date, the Zama project does not have any carbon credits associated with it.

While carbon credits have not yet been established for the Zama project, it is worth noting that the acid gas injection program has yielded tax credits for Apache Canada. To encourage the development of a CCS industry in Alberta, the provincial government, through the Alberta Department of Energy, has instituted a Royalty Credit Program (Alberta Department of Energy, 2005). This program offers a royalty reduction to companies that use CO_2 in EOR operations and that meet certain qualification criteria. Apache Canada has qualified for this tax credit, and royalty relief is currently being awarded for the G2G Pool in the Zama oil field. Applications for the F and NNN Pools at Zama have been submitted but have not yet been awarded.

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APPENDIX A

AN OVERVIEW OF ALBERTA REGULATORY AND PERMITTING SUBMITTALS

Table A-1. Historical and Proposed ERCB F Pool Approval Conditions

ERCB EOR Approval No. 10328A: Approval Specifics Summary – Original Conditions

2) For the purposes of this approval, "miscible fluid" means gas that contains:

a) A mixture of at least 0.97 mole fraction of H_2S and CO_2, with the remainder composed of other natural gas components.
b) A H_2S content not less than 0.25 mole fraction and not more than 0.40 mole fraction at any time.
c) An average H_2S content not less than 0.32 mole fraction based on a 3-month rolling average.

5) The Operator shall conduct injection, to that part of the subject pool referred to in Appendix A, in accordance with the following requirements:

a) Production, without injection, shall initially occur until the average reservoir pressure is between 14,450 kPa(g) and 13,700 kPa(g). Miscible fluid shall then be injected in sufficient volumes to maintain the average reservoir pressure between 13,700 kPa(g) and 14,450 kPa(g).
b) Wellhead injection pressure shall not exceed 8000 kPa(g) at any time.
c) The representative composition of the injected miscible fluid shall be determined on a biweekly basis, and the representative composition of the produced gas shall be determined on a monthly basis.

ERCB EOR Approval No. 10328A: Approval Specifics Summary – Amendment 1

2) For the purposes of this approval, "miscible fluid" means gas that contains:

a) A mixture of at least 0.97 mole fraction of H_2S and CO_2, with the remainder composed of other natural gas components.
b) A H_2S content not less than 0.20 mole fraction and not more than 0.40 mole fraction at any time.
c) An average H_2S content not less than 0.23 mole fraction based on a 3-month rolling average.

5) The Operator shall conduct injection, to that part of the subject pool referred to in Appendix A, in accordance with the following requirements:

a) Production, without injection, shall initially occur until the average reservoir pressure is between 15,500 kPa(g) and 14,000 kPa(g). Miscible fluid shall then be injected in sufficient volumes to maintain the average reservoir pressure between 14,000 kPa(g) and 15,500 kPa(g).
b) Wellhead injection pressure shall not exceed 8000 kPa(g) at any time.
c) The representative composition of the injected miscible fluid shall be determined on a biweekly basis, and the representative composition of the produced gas shall be determined on a monthly basis.

ERCB EOR Approval No. 10328A: Approval Specifics Summary – Amendment 2

2) For the purposes of this approval, "miscible fluid" means gas mixture with the following physical properties:

a) A minimum cumulative pseudo-critical temperature (cumulative from start of acid gas injection) of 310 K.
b) A H_2S content not more than 0.40 mole fraction at any time.
c) A methane content not more than 0.11 mole fraction based on a 3-month rolling average.

Continued . . .

Table A-1. Historical and Proposed ERCB F Pool Approval Conditions (continued)

ERCB EOR Approval No. 10328A: Approval Specifics Summary – Amendment 2
5) The Operator shall conduct injection, to that part of the subject pool referred to in Appendix A, in accordance with the following requirements: a) Production, without injection, shall initially occur until the average reservoir pressure is between 16,500 kPa(g) and 14,500 kPa(g). Miscible fluid shall then be injected in sufficient volumes to maintain the average reservoir pressure between 14,500 kPa(g) and 16,500 kPa(g). b) Wellhead injection pressure shall not exceed 8000 kPa(g) at any time. c) The representative composition of the injected miscible fluid and the representative composition of the produced gas shall be determined on a monthly basis.

July 31, 2004

Alberta Energy and Utilities Board
Resource Applications Group
640 – 5th Ave. S.W.
Calgary, AB
T2P 3G4

Attention: Cheryl Adolf
Resources Applications Group

RE: Zama – Keg River F Pool – Enhanced Oil Recovery Scheme Application

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Apache Canada Ltd. ("Apache") requests approval to implement an Enhance Oil Recovery (EOR) Miscible Flood project in the subject pool in accordance with Section 26(1)(a) of the Oil and Gas Conservation Act.

This application will discuss Apache's plans to implement a series of EOR miscible flood schemes in selected pinnacles in the Zama area but the attached document will focus primarily on the subject pool for approval. Separate applications will be submitted for each pool to eventually be included in the overall project.

The content of the attached document was written in compliance with the EUB Application Guide 65. A Guide 51 application for the injection well associated with this project will follow at a later date.

We look forward to further discussion concerning this project. If you have any further information requirements related to this application please contact either Rob Lavoie, 303-8584 or Doug Nimchuk, 261-1271.

Yours Truly,

Mike Thorson
Reservoir Engineering Manager – Apache Canada Ltd.

APPLICATION
BY
APACHE CANADA LTD.

RESOURCE APPLICATION FOR APPROVAL TO IMPLEMENT AN ENHANCED OIL RECOVERY SCHEME IN THE ZAMA KEG RIVER F POOL USING ACID GAS AS A MISCIBLE FLOODING SOLVENT

EUB GUIDE 65 SCHEDULE 1 AND SUPPORTING DOCUMENTATION

MARCH 31, 2003

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Definitions

CO_2	Carbon Dioxide
EOS	Equation of State
GOR	Gas Oil Ratio
GHG	Green House Gas
H_2S	Hydrogen Sulphide
HCPV	Hydrocarbon Pore Volume
HCPVI	Hydrocarbon Pore Volume Injected
MMP	Minimum Miscibility Pressure
OGIP	Original Gas In Place
OOIP	Original Oil In Place
PVT	Pressure Volume Temperature relationships for reservoir fluids
RGIP	Remaining Gas In Place
ROIP	Remaining Oil In Place
VRR	Voidage Replacement Ratio
WAG	Water Alternate Gas Injection Scheme

Background

Over the past three years Apache has invested significant resources into the acquisition and subsequent development of the Zama oil fields of North Western Alberta. Apache is in the process of implementing numerous waterfloods in separate oil pools consisting of relatively small Devonian Keg River pinnacles with significant vertical relief. Waterflooding and miscible flooding of these pinnacles has, in the past, proven to be a challenge for the operators in this region due to the small size and high degree of reservoir heterogeneity associated with these pools.

This document is written for the Resource Applications department of the EUB and is in accordance with Section 26(1)(a) of the Oil and Gas Conservation Act. It outlines the plans to conduct an acid gas miscible flood in the subject pool and is one of a series of applications Apache plans to submit for similar pools in the area if economic performance justifies this.

Although economics are not discussed in the attached support documentation for the EUB Guide 65, the number of pools Apache will apply enhanced recovery schemes to will depend on the economic outcome of the first series of pools and the availability of both Federal and Provincial incentives connected with the Canadian commitment to reduction in the intensity of Green House Gas (GHG) emissions.

Zama Acid Gas Miscible Flood Development Plan Overview

The Zama gas plant is currently owned and operated by Apache Canada Ltd. The plant currently generates about 175 e^3m^3/day of acid gas consisting of 20 to 40% H_2S and 80 to 60% CO_2. This amounts to a total of about 220 Tonnes/day of CO_2 and 80 Tonnes/day of H_2S. A portion of this effluent is currently processed through a Claus unit to generate elemental sulfur and sent to a sulfur block. The rest is injected into the Keg River formation using nearby acid gas injection wells.

The Zama Acid Gas Miscible Flood Project proposes to re-configure the Zama Gas Plant to inject the entire acid gas stream into nearby Keg River formation pinnacles. This will permit the use of all acid gas handled at Zama as a miscible fluid and permit the shut down of the Claus unit and eliminate the further accumulation of elemental sulfur in the block.

An estimated initial volume of 175 e^3m^3/day of acid gas is expected to be available for enhanced oil recovery use in the area. Apache has identified nine (9) candidate pools within 6 km of the Zama Gas Plant which could benefit from acid gas miscible flooding. The initial acid gas supply would be adequate to begin flooding four (4) pools. Subsequent breakthrough of acid gas solvent would then be recycled into additional candidate pools in the area. Apache estimates there could be adequate acid gas volumes over the next 4 to 5 years to flood an additional five (5) pools. Since acid gas produced with the incremental oil is conserved for recycle, it is estimated that the number of pools that can be added to the project would increase by about one to two pools per year. The initial nine pool scheme is estimated to have the potential to contribute an enhanced oil recovery reserve of 509 e^3m^3 (3.0 million barrels). Over a period of 16 years, 1 megatonne of CO_2 could be sequestered by this single project consisting of 9 pinnacles. Although there are over 600 of these pinnacles in the larger Zama area, if this project proves economic, the potential to further expand the project to an additional 80 to 100 pinnacles could exist.

Please refer to Figure 1 for a map of the Zama Area indicating the location of the Zama Gas Plant and the candidate pools.

Supporting Documentation

1. Project Location

The larger project area of all currently planned acid gas miscible flood pools is shown in Figure 1. The Zama Keg River F pool (F Pool) location is highlighted in Figure 1. The EUB G-Order boundaries for the F Pool are provided as Figure 2.

2. Previous Approvals for Zama Keg River F Pool

In September of 1987 the EUB approved a produced water disposal scheme for this pool (Board Approval No. 5471, for Application No. 871257).

3. Pool Order Number and Mapping of Pool Outline

The EUB G-Order boundaries for the F Pool are provided as Figure 2. The Zama Keg River F Pool Order number is: **POOL ORDER: 997 788006 2001-10-01**

4. Geological Description

In the Zama-Virgo oilfields the Middle Devonian Keg River Pinnacles are the primary oil producers in the area. These pinnacles were formed in a lagoon partially surrounded by banks and fronted by the Presqu'ile barrier to the west. There are over 400 pinnacles that have been discovered to date in the basin. The average size of a pinnacle is 16 ha at the base and 120m in height (approx. the size of dome stadium). The reef facies consists of common Devonian reef building organisms like tabular and bulbous stromatoporoids and tabulate corals. The reef is typically dolomitized with variable porosity and permeability. Principle rock types include wackestone, packstone, floatstone and rudstone. Porosity types range from intercrystalline to microfracture with varying degrees of alteration due to secondary leaching and dolomitization. Large vugs (greater than 5 cm) are not uncommon but can be partially occluded by calcite and anhydrite overgrowths and/or bitumen. Porosity and permeability both decrease to the tops of the reef because there was less fauna developed in the basin due to a restricted water conditions at the end of the Upper Keg River time. The reefs are sealed by impervious anhydrite of the Muskeg formation. Underlying the reefs is the Lower Keg River platform which is a tight lime mudstone and is the lower hydraulic seal. Reefs that display pressure support from an active water drive occur where the lower portion of the pinnacle is continuous below the spill point. This connects the oil pool to a large volume of porous, water-bearing Upper Keg River located radially beyond the reef. The original oil-water contact provides the maximum acid gas storage limits. There are also many pinnacles that are isolated reefs and have no aquifer support.

The Zama member of the Muskeg formation caps all the Upper Keg River reefs in the basin. In a reef crestal position it is a laminated dolomite with abundant reef building organisms and is often a continuous reservoir with the Keg River. In the flank position the Zama grades into a less porous alagal laminated mudstone and is separated from the

Keg River by a middle anhydrite. Above the Zama member the Muskeg formation ranges in thickness between 60 and 90m and is the cap rock for the underlying reefs.

The Keg River reefs are good reservoirs as they contain a high percentage of good to very good permeability. However significant variations can occur both vertically and laterally. These reefs are good candidates for CO2 miscible flooding as they are compact and contained reservoirs with oil pays up to 100m in thickness.

The pinnacles are easily identified on 3D seismic and can be reliably mapped. An aerial view of the 3D seismic interpretation of the entire Zama Acid Gas Miscible Flood Project is provided as Figure 3.

A net pay isopach map of the Zama Keg River F pool is provided as Figure 4. The two existing well locations are provided on this map. A structure contour map is also provided as Figure 5 and the location of the initial oil-water contact is noted. An annotated log cross-section is provided as Figure 6.

5. Reservoir Production Performance History

5.1. Reservoir Characterization

The F Pool was discovered in 1967 and brought on production in February of that year. A PVT sample was taken in October of 1967 by The Hudson's Bay Oil and Gas Company Limited and analyzed by Core Laboratories in November of 1967 (Reference 1). The original reservoir pressure was recorded as 14,447 kPa (2095 psig) at datum depth of -1098.6 m MSL.

By November of 1968, special core analysis was conducted on core samples taken during drilling of the 11-25 well (Reference 2). Routine core analysis was performed on the 8-13-116-6W6 discovery well and a summary of parameters derived for this work is provided as Table 1.

5.1.1. Initial Conditions

Play Type	Keg River Pinnacle Reef
Initial Reservoir Pressure	14,447 kPa
Reservoir Temperature	71 C
Initial Water Saturation	15% (from logs)
Porosity	10% (from logs)
Initial Gas Oil Ratio	52 m3/m3
Initial Formation Volume Fac.	1.183 r vol/stdvol
Bubble Point Pressure	8,791 kPa
API Gravity	35.2 API
Calculated OOIP	344 e^3m^3 (Volumetric using 3D Seismic Data)
Calculated OOIP	557 e^3m^3 (Material Balance, see discussion below)

5.1.2. Summary of Reservoir Fluid PVT Studies Conducted

One routine PVT analysis was conduced on the 08-13-116-6W6 discovery well, see Reference 1). Table 2 and 3 provide the Differential and Flash Corrected PVT data respectively used in material balance analysis for this pool.

5.1.3. Petrophysical Interpretations

Routine and special core analysis tests were conducted on cores taken from the discovery well 11-25-116-6W6, Reference 2. Waterflood coreflood experiments indicated a residual oil saturation of 30% to 50% for high permeability (100+ md) to low permeability (6 md and less) rock respectively.

The range of typical Zama Keg River core measured air permeabilities are shown in Figures 7 through 9. These figures illustrate the air permeability distribution with increasing scale on the x-axis. It is evident that most of the permeability clusters in the 100 md region but there is a substantial degree of heterogeneity represented.

Petrophysical interpretations of wireline logs are provided as Table 4.

5.2. Production Performance and Pressure History

Oil production commenced November, 1967. Cumulative oil production to date for this pool is 176.2 e^3m^3 or 51% of the OOIP calculated via volumetric analysis. Based on the material balance analysis the cumulative oil recovery would represent only 32% of the OOIP. A plot of the production performance for the pool is provided as Figure 10.

Historic reservoir pressure is also illustrated on Figure 10. It is evident from this plot that reservoir pressures depleted with primary production through to the end of the 1980's. During 10 years of shut-in through the 1990's reservoir pressure recharged to the surrounding aquifer system pressure or has been recharged as a result of water injection activities in nearby Keg River formations. Current reservoir pressure is assumed to be in the vicinity of 24,000 kPa at the reservoir datum depth based on a measurement taken in February of 2002. Since this date, a significant amount of production was withdrawn from the reservoir which may have resulted in a 5 mPa pressure depletion. Moreover, there is some uncertainty concerning the validity of the pressure taken in 2002. A pressure measurement is needed to verify the reservoir's current pressure prior to commencing the acid gas miscible flood operations.

Cumulative production of oil, water, and gas, and the pressure history at reservoir datum are provided as Table 5.

5.3. Current Estimated Conditions

Original Oil In Place calculations performed both volumetrically and by material balance are given below:

Calculated OOIP	344 e^3m^3 (Volumetric using 3D Seismic Data)
Calculated OOIP	557 e^3m^3 (Material Balance, see discussion below)

Cumulative recoveries to November 2003:

Oil	176.1 e^3m^3
Gas	15.11 e^6m^3
Water	64.5 e^3m^3
Water Injection	366.4 e^3m^3

5.4. Current Estimated Reservoir Pressures

A recent pressure measurement (02/19/2002) indicates that recharge has taken place in this reservoir to a pressure of 23,975 kPa at Datum Depth.

6. Proposed Production and Injection Wells

Two wells were drilled into the F pool:

100/01-13-116-6W6 - This well is proposed to be the future injector
100/08-13-116-6W6 – This well is currently believed to require too much down hole revisions for re-use. Plans are being made to drill a new well for production from this enhanced oil recover project.

7. Reservoir Development Plan

7.1. Proposed Acid Gas Injection Plans (Acid Gas Source and Composition)

7.1.1. Solvent Source Selection

The CO_2/H_2S source is from Apache's own operation of the three (3) Zama Gas Plants located at 13-12-116-6 W6M. These three plants have a total of four (4) amine trains which produce a source of 70 to 80% CO_2 for the project. Effluent from Plant 1 is currently being processed into elemental sulphur and stored in a block near the plant. Acid gas from the other two plants is compressed for injection into the 00/02-02-117-6W6 acid gas disposal well. Apache proposes to use the gas being injected into this disposal well as the miscible flood solvent used for this enhanced oil recovery schemes at Zama. The composition of effluent from these two plants is provided in the following table:

Plant	Acid Gas Rate, e3m3/day	CO2, Mole %	CO2+H2S Rate, e3m3/day	CO2 Rate, e3m3/day	H2S Rate, e3m3/day
2	46	76	46	35	11
3	75	77	75	58	17
Blended Comp.				**77%**	**23%**
Total, e3m3/day			**121**	**93**	**28**
Total, Tonnes/day			**210**	**170**	**40**
Mega Tonnes/Year				**0.1**	**0.01**
Mega Tonnes over 16 Year LIfe				**1.0**	**0.24**

Only a portion of the above volumes will be injected into the F pool with the remainder being injected into an additional two pools in the vicinity of the Zama gas plant (the subject of two additional companion applications, Reference 7 and 8).

7.1.2. Transportation

Figure 1 identifies the location of the pipelines required to transport acid gas from the Zama Gas Plant to the candidate pools. Apache proposes to utilize either existing pipelines if they are suitable or new pipelines for this purpose.

7.1.3. Injection Start-up Date and Proposed Injection Rate

Installation of necessary separation and compression equipment will take place over the spring and summer of 2004. Solvent injection is planned to commence as early as October or November of 2004.

Solvent injection rate depends on both the critical rate for stable advancement of the flood front (see section 7.4 below), and the maximum rate possible at a voidage replacement ratio of 1.0. Historic maximum production rate for the Zama Keg River F pool was in the order of 130 m^3 day of oil. Although a maximum injection rate of 94 reservoir m^3 day of solvent is calculated as the gravity stable critical rate, it may not be possible to sustain this rate given the maximum production rate possible from the single production well on the structure. Apache plans to inject solvent with no production until the minimum miscibility pressure (MMP) is achieved if necessary (see section 7.2). Once the MMP is reached, production will commence and a voidage replacement rate of 1.0 will be maintained. The timing of the date of first production will depend on monitoring of reservoir pressure at the proposed production well.

7.2. Minimum Miscibility Pressure Estimations and Laboratory Analysis

During the fall of 2003, fluids were sampled from the 02/11-25-116-6W6 well (and also the 00/8-13-116-6W6 well of the Zama Keg River F Pool) and shipped to the PTRC in Regina for analysis (Reference 3, and Appendix 1). These separator gas and oil samples were recombined to achieve the bubble point reported by the original PVT sample analysis done for the pool (Reference 1).

A rising bubble apparatus was used to measure the minimum miscibility pressure of the recombined oil with pure carbon dioxide and a gas mixture composed of 20 mol% hydrogen sulfide in carbon dioxide. The CO2 MMP for the 8-13 well's reservoir oil was 19.9 MPa. Addition of 20 mol% H2S to the CO2 had the effect of reducing the MMP to 16.6 MPa. Some evidence of solids participation was noted in the experiments.

In addition to this laboratory analysis, a statistical analysis of oil compositions in the Zama area was conducted and the Alston correlation for MMP estimations (Reference 4) was used to predict the MMP values prior to completing the lab analysis. Use of the Alston correlation requires the availability of a detailed reservoir fluid analysis including compositional analysis. Over a hundred detailed fluid analysis studies have been conduced on pools in the Zama area but only a few of these were conducted on the pools selected as candidates.

To arrive at an MMP for each of the candidate pools, MMP's were calculated based on Alston's correlation for each of the pools that had detailed fluid analysis, Figure 11, and a statistical correlation of these MMP's was arrived at using only API gravity and reservoir temperature. Figure 11 shows the calculated MMP values for pure CO2 as a solvent and for a mixture of 33% H2S/67% CO2. Using these correlations of MMP along with the API gravity and reservoir temperature for pools that did not have detailed PVT analysis, an MMP value was calculated for each of the nine miscible flood candidates near the Zama gas plant. Figure 12 provides the calculated MMP values for a number of pools in the target area for both the pure CO2 and H2S/CO2 mixture solvents. Also shown in Figure 12 is the original reservoir pressure and the most recent pressure measurement available to Apache. As can be seen in Figure 12, some of these candidate pools may require further pressure support depending on results of more recently acquired pressure surveys (some recharge is anticipated over time).

The laboratory measured MMP values from the PTRC for two pools sampled are plotted on Figure 12 showing that the correlation is reasonably consistent with the lab analysis results. Figure 12 shows the MMP values predicted by correlations for the F Pool to be about 17 MPa for a 33% H_2S, 67% CO_2 mixture and about 20 MPa for pure CO_2.

7.3. Estimated Miscible Flood Sweep Efficiency

Based on the F pool's current cumulative oil recovery of 176.2 e3m3 of oil, and assuming volumetric interpretations of seismic data are correct, a volumetric sweep efficiency of 72.5% has been achieved to date using the following equation:

$$\boxed{E_{Vol} = \frac{RE_{WF}}{\left(\frac{S_{oi} - S_{orw}}{S_{oi}}\right)}}$$

Where:

E_{vol} - Volumetric sweep efficiency at the end of waterflood
RE_{wf} - Current water drive recovery efficiency
S_{oi} - Initial oil saturation, (85%)
S_{orw} - Residual oil saturation to water drive, (35%)

Assuming that the residual oil in the swept zone is 35% based on a conservative estimate from special core studies, Reference 2, and assuming that the residual oil saturation in a solvent swept region of the reservoir will be about 5%, our expectation of the ultimate recovery efficiency is given by the following equation:

$$\boxed{Ultimate\_RE_{Acid\_Gas\_Flood} = \left(\frac{S_{oi} - S_{or\_acid\_gas}}{S_{oi}} \right) * E_{Vol}}$$

Where:

$S_{or\_acid\_gas}$ - Residual oil saturation to acid gas drive, (assume 5%)
$Ultimate\_RE_{Acid\_Gas\_Flood}$ - Ultimate recovery efficiency at the end of the acid gas flood.

Given the above estimates of residual oil saturations and the excellent sweep efficiency that has already been achieved in this pool, a estimate of the incremental recovery efficiency with a further 75% discounting for the possibility of poorer performance under an acid gas drive scheme is about 12.8%.

7.4. Critical Injection Rate Analysis

The maximum acid gas injection rate is an important design issues for miscible flooding in the Keg River pinnacle reefs. A gravity stable flood which moves an oil bank vertically down through the reef is the current miscible flooding concept for the Zama Keg River pinnacles. As was the case for the Rainbow Keg River systems, there is a potential problem with gravity stability which depends on the rate of gas injection. Injecting at too high a rate will induce viscous fingers through the oil column and towards the production perforations of the producing well.

To mitigate gravity instability, it is necessary to calculate a rate at which vertical injection will maintain a gravity stable flood front moving downward through the pinnacle. (Dake, Reference 5) published a gravity stability analysis involving the following calculations:

$$\boxed{q_{crit} = \frac{4.9x10^{-4} kk_{rg}^{'} A \Delta \gamma \sin \theta}{\mu_g (M - 1)}}$$

Where:

q_{crit} - Maximum rate at which injection of acid gas will be stable for moving a fluid column vertically downward through a residual oil column, rb/day
k - Absolute reservoir permeability, md
k_{rg} - Relative permeability end-point to gas, dimensionless
A - Effective cross-sectional area being pushed downward by the injected gas, ft^2
$\Delta\gamma$ - Specific gravity difference between the oil zone and the injected gas zone, relative to water density
θ - Angle of elevation of the reservoir, in the case of vertical drive downward through the Keg River Pinnacles, this is 90 degrees
μ_g - Viscosity of the injection gas at reservoir conditions, acid gas, cp

M - Mobility ratio between injected gas and the oil zone defined as:

$$\boxed{M = \frac{k'_{rg}/\mu_g}{k'_{ro}/\mu_o}}$$

Where:

k_{ro} - End-point relative permeability to oil
μ_o - Oil viscosity at reservoir conditions

A set of example calculations are provided as Table 6. The critical rate is highly dependent on, among those items listed above, the effective cross-sectional area exposed to the injected gas that is pushing the oil bank vertically downward. A larger effective area will result in a higher critical rate. Given that the Zama pinnacles are highly heterogeneous and that injection is occurring at a single injection site, it is difficult to predict this value. Further reservoir modeling will need to be performed to improve Apache's understanding of this relationship.

Apache proposes to operate the F pool acid gas miscible flood at a maximum critical rate of 100 rm^3/day which translates to an injection rate at standard conditions of as high as 50 e^3m^3/day of acid gas injection or 90 tonnes/day of acid gas injection. It is possible that this rate will exceed the true stable rate. If this is the case, Apache is considering the use of a technique which has been tried for the Rainbow Keg River field involving cyclic injection and shut-in of production to stabilize the flood front, Reference 6. If cyclic injection is necessary to stabilize the flood front, additional pinnacles will need to be identified for the project in order to utilize all of the available acid gas from the Zama Plant site.

7.5. Performance Forecast Methodology – By Analogue Method

Significant effort towards reservoir modeling of the Zama Keg River pinnacle performance under a miscible flooding scheme will be necessary to both predict performance and to monitor performance of the currently proposed pilot project. Compositional or pseudo-compositional numerical simulation would be required for this. Although history matching efforts towards this are currently underway, numerical predictions of miscible flood performance have not yet been completed. The University of Regina has been commissioned to conduct this simulation research. Moreover, the accuracy of performance predictions using a numerical simulator for such a heterogeneous reservoir system may be questionable until actual miscible flood performance data is available for history matching purposes.

Given a practical need to estimate miscible flood performance for the project, a preliminary performance assessment was conducted using the historical performance of the Rainbow Keg River reef oil pools south of the Zama field. The Rainbow Keg River reefs have been undergoing hydrocarbon miscible flooding since the early 1960's. Some of these pools are in late stages of mature miscible flooding with over 1.5 hydrocarbon pore volumes of solvent injected. Unfortunately, many of these pools were never waterflooded before initiating the miscible flood. This complicates their use as an analogue for the Zama Keg River pools which were produced either through natural or artificial waterflood drive. Figure 13a provides a conformance plot for all solvent flooded Rainbow Keg River pools. Figure 13b breaks out those pools which had solvent injection beginning after significant waterflood recovery had been achieved thereby representing more direct analogues for the Zama Keg River planned miscible flood schemes. Performance of the Keg River pools were modeled against the behavior illustrated in Figure 13b. Figure 14a and 14c provides the recovery efficiency versus hydrocarbon pore volume relationships, for both early and late solvent breakthrough cases respectively, used in our preliminary screening study. Figure 14b and 14d provides an estimate of the solvent breakthrough behavior expected, for both early and late solvent breakthrough cases respectively – also modeled against the Rainbow Keg River miscible flood behavior.

As can be seen in Figures 14a and 14b Apache has modified the expected recovery performance for the late breakthrough cases for the Zama acid gas flood relative to the Rainbow Keg River analogues. Apache believes that a different completion strategy that involves perforating the production wells at a lower point in the reef relative to the gas injection level could result in a delayed gas breakthrough performance compared to that observed in the Rainbow Keg River analogues. Apache has, however, uses the direct analogue curves as a worst case scenario (Figures 14b and 14d) for breakthrough which is accompanied by an accelerated oil recovery profile but is discounted by 50% for poorer sweep efficiency rather than 75% as discussed in section 7.3 (the sweep efficiency discussion).

Oil recovery rate profiles for both the early and later breakthrough cases are shown in Figures 15a and 15b for both the early and late acid gas breakthrough cases respectively. The late breakthrough achieves an incremental recovery of 19.8% while the early breakthrough case achieves an ultimate incremental recovery of 13%. Both cases involve a significant amount of recycling of injected acid gas.

Operation of the candidate pools at a reservoir pressure near or above the MMP is assumed to be possible. Acid gas injection it self will be used to pressurize the F pool to be near or above the 16.6 MPa required for miscibility as estimated using Apache Canada

Ltd's estimation from MMP correlations. Based on a pressure measurement taken in the F pool in November of 2001, current reservoir pressure at the datum depth is 23,975 kPa.

Tabulations of the expected oil, water, and gas, production as well as solvent injection and breakthrough rates for both the early and late breakthrough cases are provided as Tables 7 and 8 respectively. Figures 16a and 16b are provided to illustrate the forecasted oil rates for these two sensitivity cases.

7.6. Material Balance Analysis of Original Oil in Place

A material balance analysis of the original oil in place was possible using the early production data and pressure measurement take for the Zama Keg River F pool. Figure 17 shows the result of this material balance and indicates an Original Oil in Place value of 556.5 e3m3 (3.5 mmbbl oil). However, due to the possible interconnectivity of this pools with both other pinnacles in the region, material balance analysis is complicated and would require additional analysis that considers inter-pool connectivities.

8. Reserves Summary

8.1. Initial Oil in Place

The most reliable Initial Oil in Place analysis method for the F pool is the volumetric analysis due to complications with communicating reservoirs in the vicinity of this pool as discussed above. This volumetrically assessed Original Oil in Place value is: 344 e^3m^3 oil (2.166 mmbbl oil).

8.2. Current Cumulative Recovery and Remaining Oil in Place

The current cumulative recovery of oil from this pool is 176 e^3m^3 or 51.2% of the OOIP calculated via volumetric analysis. Based on the volumetrically determined Initial Oil in Place this leaves a Remaining Oil in Place of 168 e^3m^3.

8.3. Estimated Enhanced Oil Recovery Performance

The estimated incremental recovery performance predictions indicate the possibility for incremental recoveries of between 8.5% and 12.8%, amounting to incremental production of between 29 to 44 e^3m^3 of enhanced oil recovery. There is no further waterflood or primary production potential in this pool.

8.3.1. Production and Injection Forecasts

Tables 7 and 8 and Figure 16a and 16b provide the range of possible production performance expected for this enhanced oil recovery scheme given conditions where breakthrough occurs early or late respectively.

8.3.2. Solvent Breakthrough Forecast

Tables 7 and 8 provide the range of possible acid gas breakthrough performance expected for this pool under this enhanced oil recovery scheme given conditions where acid gas breakthrough occurs early or late respectively.

8.4. Ultimate Expected Recovery Efficiency

The ultimate recovery efficiency for the life of the F pool could therefore be increased from the current value of 51.2% to a range of 59.7% to 64% of the original oil in place. This relatively good performance is predicted on the basis of relatively good sweep efficiency achieved by the natural water drive which was supplemented by some artificial water injection.

9. Guide 51 Compliance Plans

A Guide 51 submission for the planned 00/01-13-116-6W6 acid gas injection well will be submitted once this well has been completed for acid gas injection service.

10. Notifications and Safety Plans

All individuals who are impacted by the zone of possible acid gas emission will be notified. Apache will forward these responses to the EUB once they are available. Site specific emergency response plans will be compiled and submitted for approval by the EUB.

References

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4. R.B. Alston, etal, “CO_2 Minimum Miscibility Pressure: A Correlation for Impure CO_2 Streams and Live Oil Systems”, Society of Petroleum Engineers Journal, April 1985.
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6. I. Adamache, et al, “The Effect of Cyclic Flow Interruptions on the Performance of Vertically Directed Miscible Floods”, SPE 22935, 66th Annual Technical Conference and Exhibition of the SPE held in Dalas, TX, October 6-9, 1991.
7. Apache Canada Ltd, “Resource Application for Approval to Implement an Enhanced Oil Recovery Scheme in the Zama Keg River G2G Pool Using Acid Gas as a Miscible Flooding Solvent”, March 2004.
8. Apache Canada Ltd, “Resource Application for Approval to Implement an Enhanced Oil Recovery Scheme in the Zama Keg River NNN Pool Using Acid Gas as a Miscible Flooding Solvent”, March 2004.

Core Data from: Zama Keg River F Pool - Well 8-13-116-6W6

Core Sample No.	feet	Depth, Top of Sample, m	Depth, Bottom of Sample, m	Length of Sample, m	K Max	K Vertical	Perm Meters, md.m	Porosity, %	Porosity meters m
89	4901	1493.8	1494.1	0.3	3.75	0.35	1.0	5.9	0.016
90	4901.9	1494.1	1494.5	0.4	12.6	8.25	5.4	11.6	0.049
91	4903.3	1494.5	1494.9	0.3	41.8	2.06	14.0	7.2	0.024
92	4904.4	1494.9	1495.2	0.3	1.55	1.38	0.5	7.1	0.024
93	4905.5	1495.2	1495.6	0.4	4.01	3.01	1.5	6.6	0.024
94	4906.7	1495.6	1495.9	0.4	16.3	3.25	6.0	8.5	0.031
95	4907.9	1495.9	1496.2	0.3			0.0	7	0.019
96	4908.8	1496.2	1496.6	0.4		1510	0.0	13.3	0.049
97	4910	1496.6	1496.8	0.2	19.7	4.46	4.8	6.9	0.017
98	4910.8	1496.8	1497.0	0.2	62.8	1.75	9.6	5.4	0.008
99	4911.3	1497.0	1497.2	0.2	12.3	7.4	3.0	11.6	0.028
100	4912.1	1497.2	1497.4	0.2		8.08	0.0	7.7	0.016
101	4912.8	1497.4	1497.7	0.2	8280	6.58	2019.0	9.6	0.023
102	4913.6	1497.7	1498.0	0.4		0.37	0.0	6.8	0.025
103	4914.8	1498.0	1498.3	0.3	26.5	2.03	8.1	9.3	0.028
104	4915.8	1498.3	1498.6	0.3	106	2.61	29.1	15.2	0.042
105	4916.7	1498.6	1498.8	0.2		0.94	0.0	17.9	0.033
106	4917.3	1498.8	1499.0	0.2	2.52	0.07	0.6	11.2	0.027
107	4918.1	1499.0	1499.4	0.3	0.04	0.01	0.0	3.6	0.012
108	4919.2	1499.4	1499.7	0.4	1.66	0.7	0.6	3.9	0.014
109	4920.4	1499.7	1500.0	0.2		0.37	0.0	1.4	0.003
110	4921.2	1500.0	1500.2	0.2	6.43	1.71	1.6	4.5	0.011
111	4922	1500.2	1500.4	0.2		4.28	0.0	10.7	0.020
112	4922.6	1500.4	1500.6	0.2	2.71	0.48	0.6	1.6	0.003
113	4923.3	1500.6	1500.9	0.3	6.55	0.01	2.0	2.7	0.008
114	4924.3	1500.9	1501.2	0.3	1.3	0.38	0.4	2.2	0.007
115	4925.3	1501.2	1501.6	0.3	0.74	0.01	0.2	2.7	0.009
116	4926.4	1501.6	1502.0	0.4			0.0	3.4	0.015
117	4927.8	1502.0	1502.4	0.4	0.1	0.01	0.0	5.5	0.022
-	4929.1	1502.4							
118	4934	1503.9	1504.1	0.2	0.23	0.08	0.1	4.1	0.010
119	4934.8	1504.1	1504.4	0.2	0.04	0.08	0.0	2.3	0.006
120	4935.6	1504.4	1504.6	0.2	0.11	0.15	0.0	4.8	0.012
121	4936.4	1504.6	1504.9	0.2	0.08	0.04	0.0	2.5	0.006
122	4937.2	1504.9	1505.1	0.2	0.08	0.08	0.0	4.5	0.011
123	4938	1505.1	1505.3	0.2	0.08	0.04	0.0	2.8	0.007
-	4938.8	1505.3							
124	4943.7	1506.8	1507.2	0.4	3360	1990	1229.0	22.5	0.082
125	4944.9	1507.2	1507.4	0.2			0.0	18	0.033
-	4945.5	1507.4							
126	4946.2	1507.6	1507.9	0.3	336	159	92.2	14.5	0.040
127	4947.1	1507.9	1508.1	0.2	188	39.6	45.8	12.2	0.030
128	4947.9	1508.1	1508.3	0.2	2600	770	554.7	23.6	0.050
129	4948.6	1508.3	1508.6	0.2			0.0	3	0.007
130	4949.4	1508.6	1508.8	0.2	231	37.7	42.2	11.8	0.022
-	4950	1508.8							
131	4951	1509.1	1509.3	0.3		3.17	0.0	13.1	0.036
132	4951.9	1509.3	1509.6	0.2	244	157	52.1	8.3	0.018
133	4952.6	1509.6	1509.8	0.2		10400	0.0	21.6	0.046
134	4953.3	1509.8	1510.0	0.3		1500	0.0	20.5	0.056
135	4954.2	1510.0	1510.3	0.2		424	0.0	16.7	0.041
136	4955	1510.3	1510.5	0.2	168	69.3	35.8	12.6	0.027
137	4955.7	1510.5	1510.6	0.2		17.6	0.0	14.5	0.022
138	4956.2	1510.6	1510.9	0.2	228	152	48.6	13.6	0.029
139	4956.9	1510.9	1511.2	0.3	338	30.5	103.0	10.1	0.031
140	4957.9	1511.2	1511.4	0.2	1100	90.3	234.7	9.7	0.021
141	4958.6	1511.4	1511.6	0.2	1130	464	275.5	13.3	0.032
142	4959.4	1511.6	1511.8	0.2	27.1	39.6	5.8	9.3	0.020
143	4960.1	1511.8	1512.1	0.2	9.57	3.72	2.3	6	0.015
144	4960.9	1512.1	1512.5	0.5	354	189	161.8	11.3	0.052
145	4962.4	1512.5	1512.8	0.2	141	22	34.4	5.5	0.013
146	4963.2	1512.8	1513.1	0.3				7.5	0.023
-	4964.2	1513.1							
147	4975	1516.4	1516.7	0.3	504	159	169.0	8.8	0.030
148	4976.1	1516.7	1517.0	0.3		52.8	0.0	16.4	0.050
149	4977.1	1517.0	1517.3	0.3			0.0	25.5	0.078
150	4978.1	1517.3	1517.6	0.3		5290	0.0	8.2	0.025
151	4979.1	1517.6	1517.9	0.3		833	0.0	15.8	0.048
152	4980.1	1517.9	1518.2	0.3		2.44	0.0	11.4	0.031
153	4981	1518.2	1518.6	0.4	0.7	0.52	0.3	1.6	0.006
154	4982.3	1518.6	1519.0	0.4	4.31	1.38	1.6	4	0.015
155	4983.5	1519.0	1519.4	0.4	5150	5.88	2197.6	9.6	0.041
156	4984.9	1519.4	1519.7	0.3		0.1	0.0	4.8	0.013
157	4985.8	1519.7	1519.9	0.2	30.7	2.89	7.5	4.6	0.011
158	4986.6	1519.9	1520.4	0.5	53.2	14	27.6	1.7	0.009
159	4988.3	1520.4	1521.1	0.6	0.44	0.01	0.3	1.1	0.007
160	4990.4	1521.1	1521.6	0.5	7.49	11.3	3.9	2.8	0.015
161	4992.1	1521.6	1522.1	0.5	40.3	21.5	20.9	1.8	0.009
162	4993.8	1522.1	1522.5	0.4	0.12	0.01	0.0	1	0.004
163	4995	1522.5	1522.9	0.5	0.08	0.01	0.0	1.4	0.006
164	4996.5	1522.9	1523.4	0.5	1.06	0.25	0.5	2.5	0.011
165	4998	1523.4	1523.8	0.5	44.7	21.5	20.4	3	0.014
166	4999.5	1523.8	1524.2	0.3	2.27	2.88	0.8	2.2	0.007
167	5000.6	1524.2	1524.6	0.4	1830	176	725.1	8.1	0.032
168	5001.9	1524.6	1524.9	0.3	10.8	3.27	3.0	3.5	0.010
169	5002.8	1524.9	1525.2	0.4			0.0	9	0.036
170	5004.1	1525.2	1525.4	0.2			0.0	11.3	0.021
171	5004.7	1525.4	1525.7	0.2			0.0	16.9	0.041
172	5005.5	1525.7	1526.1	0.4		32.8	0.0	11.3	0.045
173	5006.8	1526.1	1526.4	0.4		344	0.0	12.2	0.045
174	5008	1526.4	1526.7	0.3		69.1	0.0	10.1	0.028
175	5008.9	1526.7	1527.1	0.4		1.52	0.0	3.7	0.014
-	5010.1	1527.1							
176	5012	1527.7	1527.8	0.2			0.0	30	0.055
177	5012.6	1527.8	1528.2	0.4	65.6	0.56	24.0	5.3	0.019
178	5013.8	1528.2	1528.4	0.2		9.56	0.0	8	0.017
179	5014.5	1528.4	1528.7	0.3	93.1	49.6	25.5	5.6	0.015
180	5015.4	1528.7	1529.1	0.4			0.0	14.9	0.054
181	5016.6	1529.1	1529.4	0.3	6.33	6.38	1.9	2.9	0.009
182	5017.6	1529.4	1529.6	0.3	11.7	16.4	3.2	3.6	0.010
183	5018.5	1529.6	1529.9	0.2	18.4	8.39	4.5	2.9	0.007
184	5019.3	1529.9	1530.2	0.3	9800	321	2688.3	9.5	0.026
185	5020.2	1530.2	1530.4	0.3			0.0	10.5	0.029
186	5021.1	1530.4	1530.6	0.2	55.8	98.4	11.9	6.8	0.015
187	5021.8	1530.6	1531.0	0.3	149	130	50.0	6.5	0.022
188	5022.9	1531.0	1531.3	0.3	33	13.9	11.1	6	0.020
189	5024	1531.3	1531.7	0.3	393	509	131.8	7	0.023
190	5025.1	1531.7	1531.9	0.2	19.9	6.56	4.9	4.3	0.010
191	5025.9	1531.9	1532.0	0.2	125	5.25	19.1	6.9	0.011
192	5026.4	1532.0	1532.3	0.2	71.8	52.8	15.3	8.4	0.018
193	5027.1	1532.3	1532.4	0.2		28.8	0.0	16.3	0.030
194	5027.7	1532.4	1532.6	0.2	13.5	0.1	2.1	4.5	0.007
195	5028.2	1532.6	1532.9	0.3	27.5	6	8.4	3.4	0.010
196	5029.2	1532.9	1533.2	0.3		21.4	0.0	3.5	0.011
197	5030.2	1533.2	1533.5	0.3	1610	10.6	490.7	10.1	0.031
198	5031.2	1533.5	1533.9	0.4	81.1	27.5	29.7	10.1	0.037
198b	5032.4	1533.9	1534.3	0.4	81.1	27.5	32.1	10.1	0.040
199	5033.7	1534.3	1534.6	0.3	12800	1460	3901.4	14.1	0.043
200	5034.7	1534.6	1534.9	0.3	2000	165	548.6	11.5	0.032
201	5035.6	1534.9	1535.2	0.3	874	20.5	266.4	7.3	0.022
202	5036.6	1535.2	1535.4	0.3	385	69	105.6	10	0.027
203	5037.5	1535.4	1535.7	0.3		556	0.0	14.4	0.044
-	5038.5	1535.7							
Total				34.5			16581.1		
Average				0.30	693.2	276.9	144.2	8.6	0.0
Length Wgtd Ave.				0.32	480.1	228.1		8.1	
Std Deviation				0.087546	2101.883	1172.197	531.2566	5.697966	0.015583
Variance				0.007664	4417910	1374046	282233.5	32.46682	0.000243

Kv/Kh Ratio	**0.40**	**Average**
Kv/Kh Ratio	**0.47**	**Length Wgtd Ave.**

Table 2

Differential Liberation PVT Data

Differential Liberation	Well	8-13-116-6W6			
0					
Tres	**Pressure**	**Bubble Pt.**	**Soln GOR**	**Oil FVF**	**Visc**
(deg F)	**(kPag)**	**(kPag)**	**(m3/m3)**	**(resVol/Vol)**	**(cp)**
71.1	34475	8791		1.174	1.68
71.1	31028	8791		1.178	
71.1	30338	8791			1.61
71.1	27580	8791		1.182	
71.1	26201	8791			1.54
71.1	24133	8791		1.187	
71.1	22064	8791			1.47
71.1	20685	8791		1.191	
71.1	17927	8791			1.41
71.1	17238	8791		1.196	
71.1	13790	8791		1.201	1.34
71.1	12411	8791		1.203	
71.1	11722	8791		1.204	
71.1	11032	8791		1.205	
71.1	10343	8791		1.206	1.28
71.1	9653	8791		1.207	
71.1	8964	8791		1.208	
71.1	8791	8791	58	1.209	1.26
71.1	8729	8791			
71.1	8667	8791			
71.1	8550	8791			
71.1	8329	8791			
71.1	7943	8791	54	1.201	
71.1	7929	8791			1.29
71.1	7343	8791			
71.1	7102	8791			1.34
71.1	7081	8791	51	1.192	
71.1	6771	8791			
71.1	6206	8791	46	1.183	1.41
71.1	6095	8791			
71.1	5413	8791			
71.1	5357	8791	42	1.173	
71.1	5309	8791			1.47
71.1	4723	8791			
71.1	4496	8791	38	1.163	
71.1	4482	8791			1.56
71.1	4103	8791			
71.1	3585	8791	33	1.152	1.66
71.1	3516	8791			
71.1	3117	8791			
71.1	2758	8791	30	1.142	1.76
71.1	2427	8791			
71.1	1875	8791			
71.1	1862	8791			1.89
71.1	1841	8791	23	1.129	
71.1	1324	8791			
71.1	1034	8791			2.04
71.1	1000	8791	17	1.114	
71.1	552	8791			2.22
71.1	531	8791	13	1.101	
71.1	0	8791		1.046	2.64

Table 3
Flash Corrected PVT Data

						GOR
Adjusted PVT data Separator Flash Conditio		**psig**		**kPa**		**m3/m3**
First Stage Flash	**from**	**8791**	**to**	**552**	**at**	**42.2**
Second Stage Flash at	**from**	**552**		**0**	**at**	**8.2**
Total Flash GOR	**50.3**	**m3/m3**				**50.3**
Flash FVF	**1.2074**	**rvol/svol**				
Tres (deg C)	**Pressure kPa**	**Bubble Pt. kPa**	**Soln GOR m3/m3**	**Oil FVF (rvol/svol)**	**Visc (cp)**	
71.1	34475	8791	50.3	1.1492	1.24	
71.1	31028	8791	50.3	1.1530		
71.1	30338	8791	50.3		1.19	
71.1	27580	8791	50.3	1.1572		
71.1	26201	8791	50.3		1.17	
71.1	24133	8791	50.3	1.1615		
71.1	22064	8791	50.3		1.14	
71.1	20685	8791	50.3	1.1658		
71.1	17927	8791	50.3		1.33	
71.1	17238	8791	50.3	1.1702		
71.1	13790	8791	50.3	1.1753	1.53	
71.1	12411	8791	50.3	1.1774		
71.1	11722	8791	50.3	1.1785		
71.1	11032	8791	50.3	1.1795		
71.1	10343	8791	50.3	1.1805		
71.1	9653	8791	50.3	1.1817		
71.1	8964	8791	50.3	1.1828		
71.1	8791	8791	50.3	1.1830		Bubble Point
71.1	8729	8791				
71.1	8667	8791				
71.1	8550	8791				
71.1	8329	8791				
71.1	7943	8791	46.5	1.1752		
71.1	7929	8791			1.19	
71.1	7343	8791				
71.1	7102	8791			1.17	
71.1	7081	8791	42.9	1.1664		
71.1	6771	8791				
71.1	6206	8791	38.5	1.1576	1.22	
71.1	6095	8791				
71.1	5413	8791				
71.1	5357	8791	34.5	1.1478		
71.1	5309	8791			1.64	
71.1	4723	8791				
71.1	4496	8791	30.0	1.1380		
71.1	4482	8791				
71.1	4103	8791				
71.1	3585	8791	25.4	1.1272		
71.1	3516	8791				
71.1	3117	8791				
71.1	2758	8791	22.8	1.1174		
71.1	2427	8791				
71.1	1875	8791				
71.1	1862	8791				
71.1	1841	8791	15.6	1.1047		
71.1	1324	8791				
71.1	1034	8791				
71.1	1000	8791	9.9	1.0900		
71.1	552	8791				
71.1	531	8791	5.8	1.0773		
71.1	0	8791		1.0235		

Figure 16b
EOR Oil Rate
Keg River F Recovery Profile - Late Breakthrough

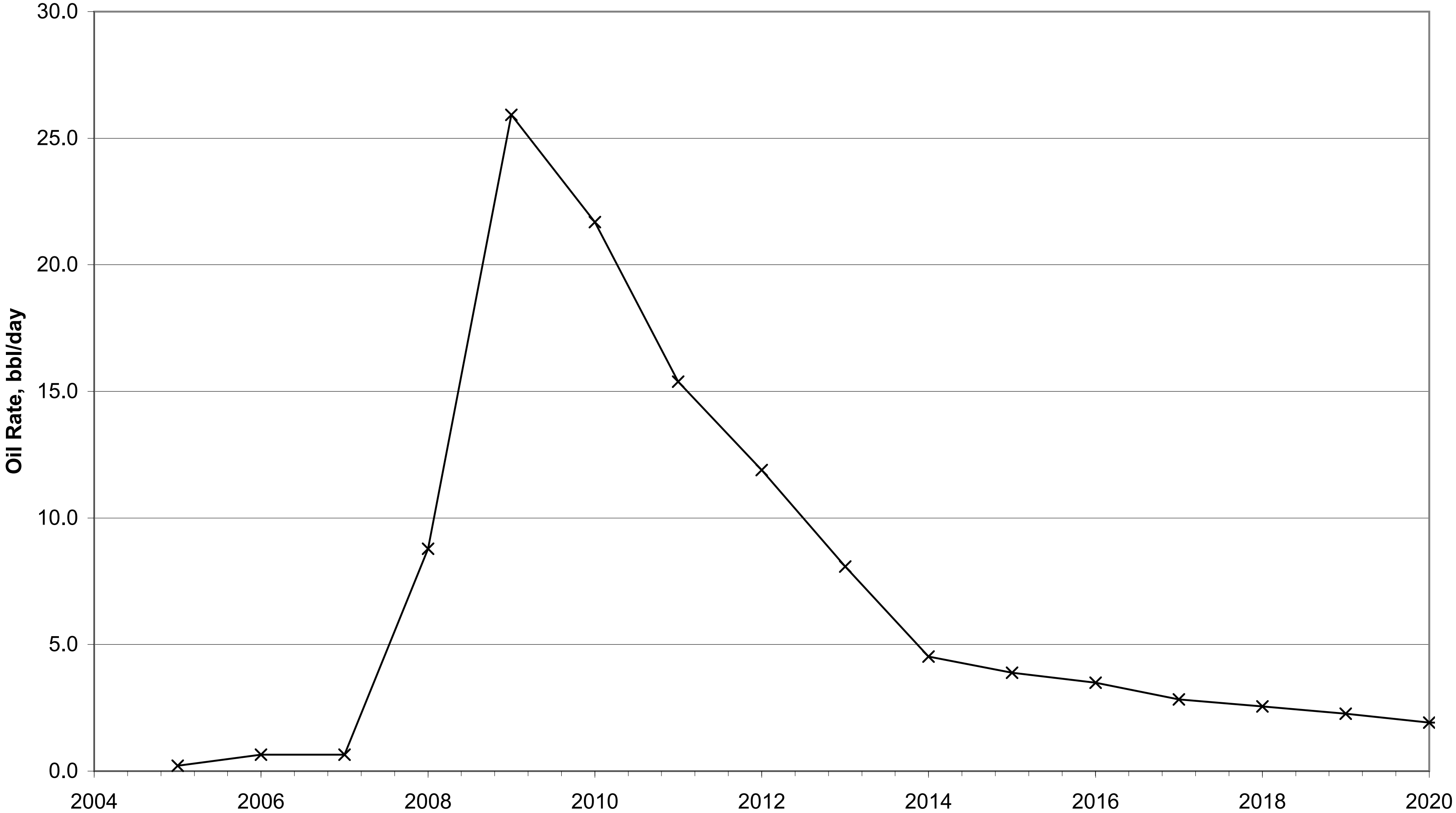


Table 4 (2 of 2)

Keg River Reef:

The Keg River formation was from 1502 meters to the base of the logs (1551.0 meters KB). The upper section (from 1502.0 –1517.5 meters) had a large difference between the average porosities of the neutron-density and the neutron-acoustic (up to 5.8%). The density log is reading abnormally high and this is due to potential rugose borehole conditions (no caliper run over this section), which could be caused by micro-fractures and/or vugs. The core porosity matches reasonably well with the neutron-acoustic porosity but there are sections that have a poor fit (see plots).

Zama Member/Keg River (N-D porosity)

Data was accepted into the Net Pay Summary if the following criteria were met.

Analysis Porosity...............	**greater than or equal**	**.030**	**and less than or equal**	**1.000**
Analysis Sw.....................	**greater than or equal**	**.000**	**and less than or equal**	**.400**
Volume of Shale................	**greater than or equal**	**.000**	**and less than or equal**	**.300**

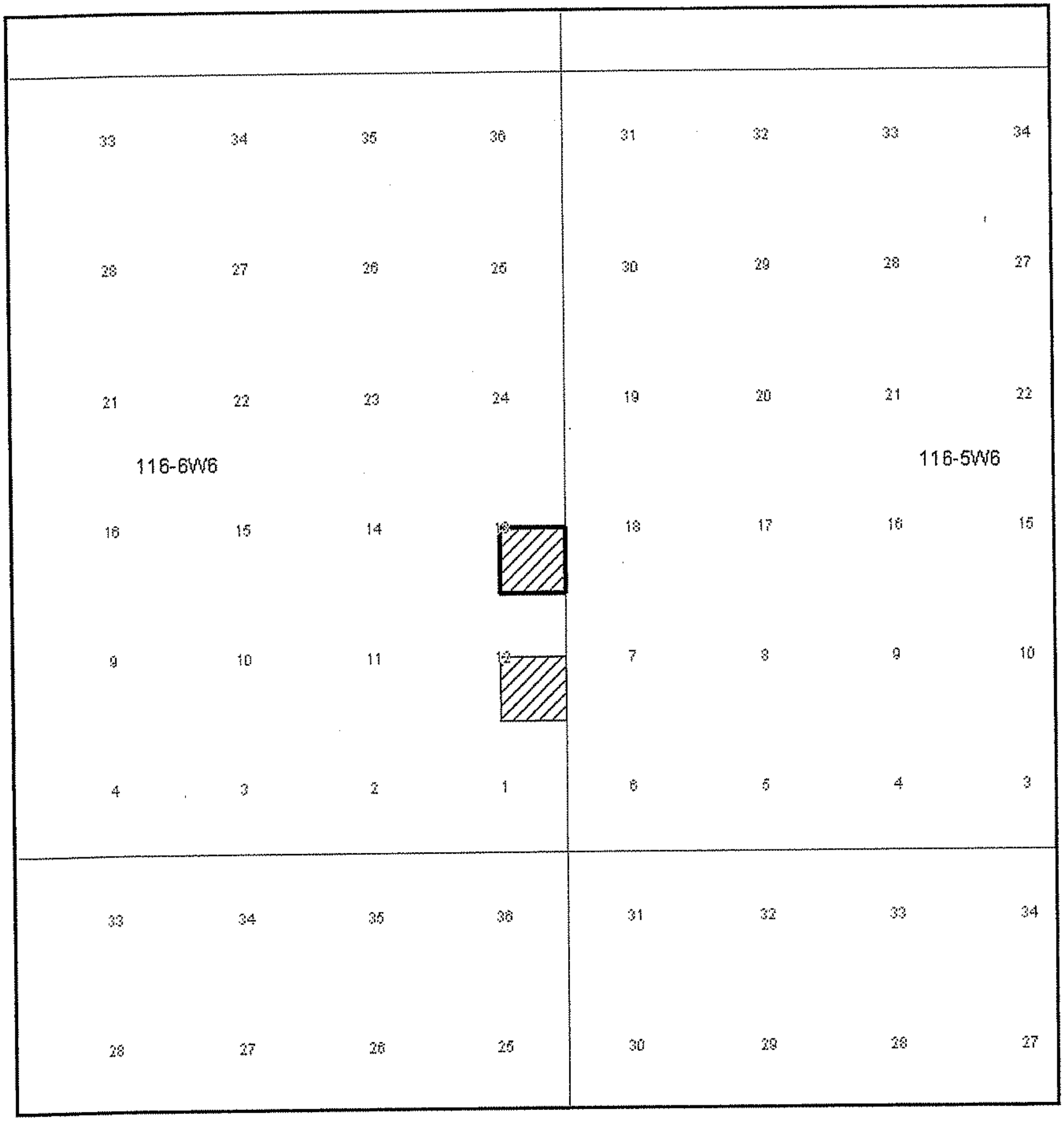
UWI	Location	Top	Base	Cum. PhiH	Cum. Hyd. Pore Vol.	Cum. H meters	Cum. kH	Average Porosity	Avg. Water Saturation
100081311606W60	100/ 08-13-116- W6	1467	1477	1.358	1.172	9.3	0	0.146	0.137
100081311606W60	100/ 08-13-116- W6	1477	1490	0.928	0.728	9.9	0	0.094	0.215
100081311606W60	100/ 08-13-116- W6	1490	1502	0.168	0.123	2.1	0	0.08	0.265
100081311606W60	100/ 08-13-116- W6	1502	1512	1.905	1.68	9.5	0	0.201	0.118
100081311606W60	100/ 08-13-116- W6	1512	1520	0.428	0.361	2.7	0	0.159	0.158
100081311606W60	100/ 08-13-116- W6	1533	1540	0.769	0.601	5	0	0.154	0.219

Table 5

SUMMARY OF RESERVOIR OFF-TAKE, VOLUMETRIC and MATERIAL BALANCE CALCULATIONS

Analysis of Current Bubble Point from Remaining Oil and Gas in the Reservoir	**Imperial**		**Metric**		
Original Solution GOR (from PVT report)	284	scf/bbl	50.3	m3/m3	
OOIP Volumetric	2.166	mmbbl	0.34	Mm3	
OOIP Material Balance	3.665	mmbbl	0.58	Mm3	
OGIP(solution gas) Volumetric	615	mmscf	17.3	Mm3	
OGIP(solution gas) Matatial Balance	1041	mmscf	29.3	Mm3	
Cum Gas Prod	536.53	mmscf	15.1	Mm3	
Cum Oil Prod	1.10817	mmbbl	0.18	Mm3	
Cum GOR	484.16	scf/bbl	85.8	m3/m3	
Remaining Gas Volumetric	79	mmscf	2.2	Mm3	
Remaining Gas Mat Balance	504	mmscf	14.2	Mm3	
Remaining Oil Volumetric	1.06	mmbbl	0.17	Mm3	
Remaining Oil Mat Balance	2.56	mmbbl	0.41	Mm3	
Rem GOR Volumetric	74.32	scf/bbl	13.2	m3/m3	
Rem GOR Mat balance	197.25	scf/bbl	35.0	m3/m3	
Current Sat Pressure using Volumetrics	213	psi	1469	kPa	from Flash Corrected PVT Table, this value is impossible
Current Sat Pressure using Mat Balance	763	psi	5261	kPa	from Flash Corrected PVT Table
Lowest Pressure Measured Pressure	551	psi	3800	kPa	
Original Sat Pressure PVT	1275	psi	8791	kPa	

POOL ORDER: 997 788006 2001-10-01



Field/Pool Code: **997 788006** Effective Date: **2001-10-01**

Field Name: **ZAMA**

Pool Name: **KEG RIVER F**

Reference Well: **00/08-13-116-06W6/0**

Well Depth: **1467.61 - 1518.51 m**

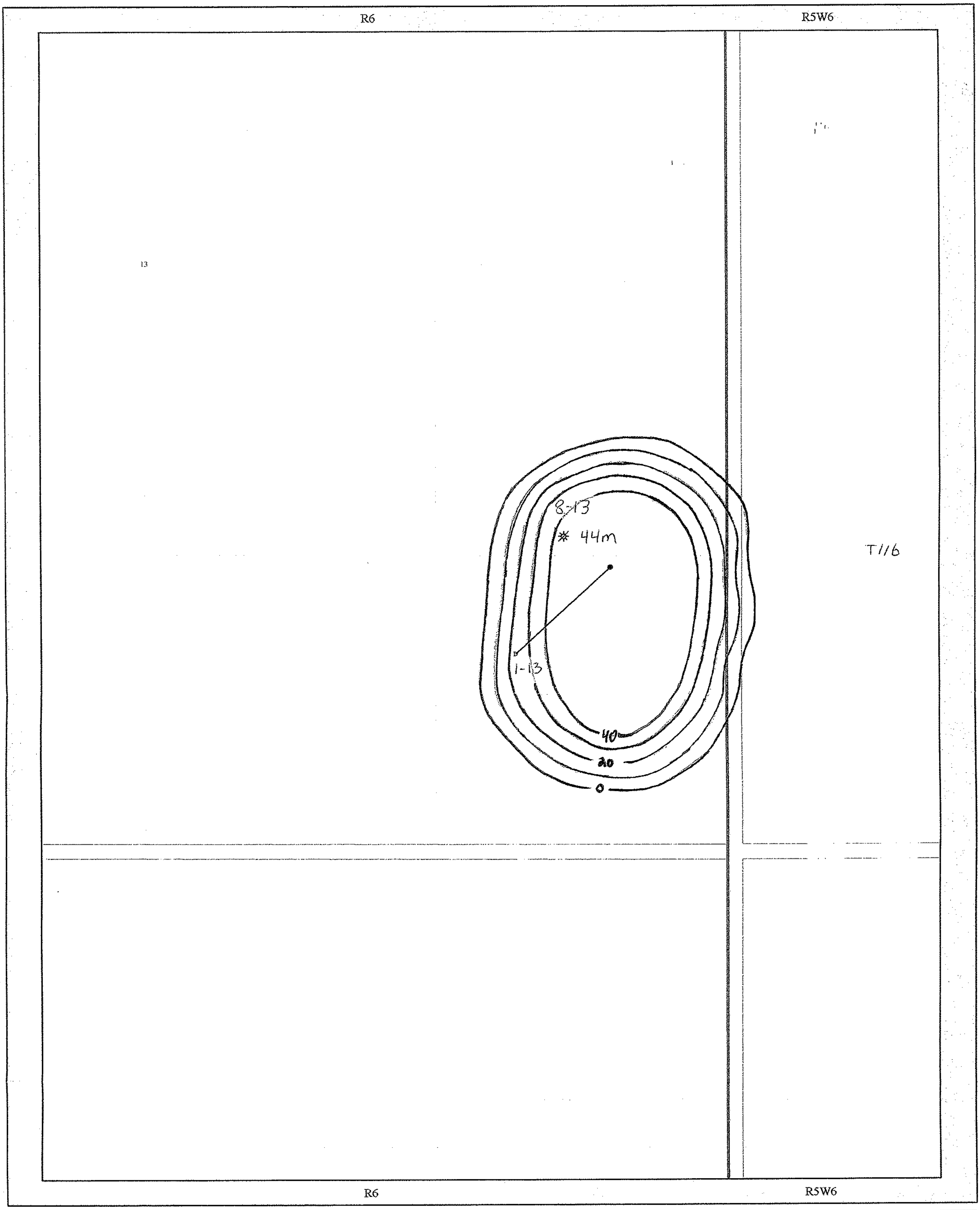
Area of Change: //////

Pool Order 997 788006 2001-02-01 is rescinded.

EUB

Alberta Energy and Utilities Board

Figure 2



WELL LEGEND
Bottom Hole Locations:
¤ Service or Drain • Oil
※ Suspended Gas

Figure 4

Apache Canada Ltd.

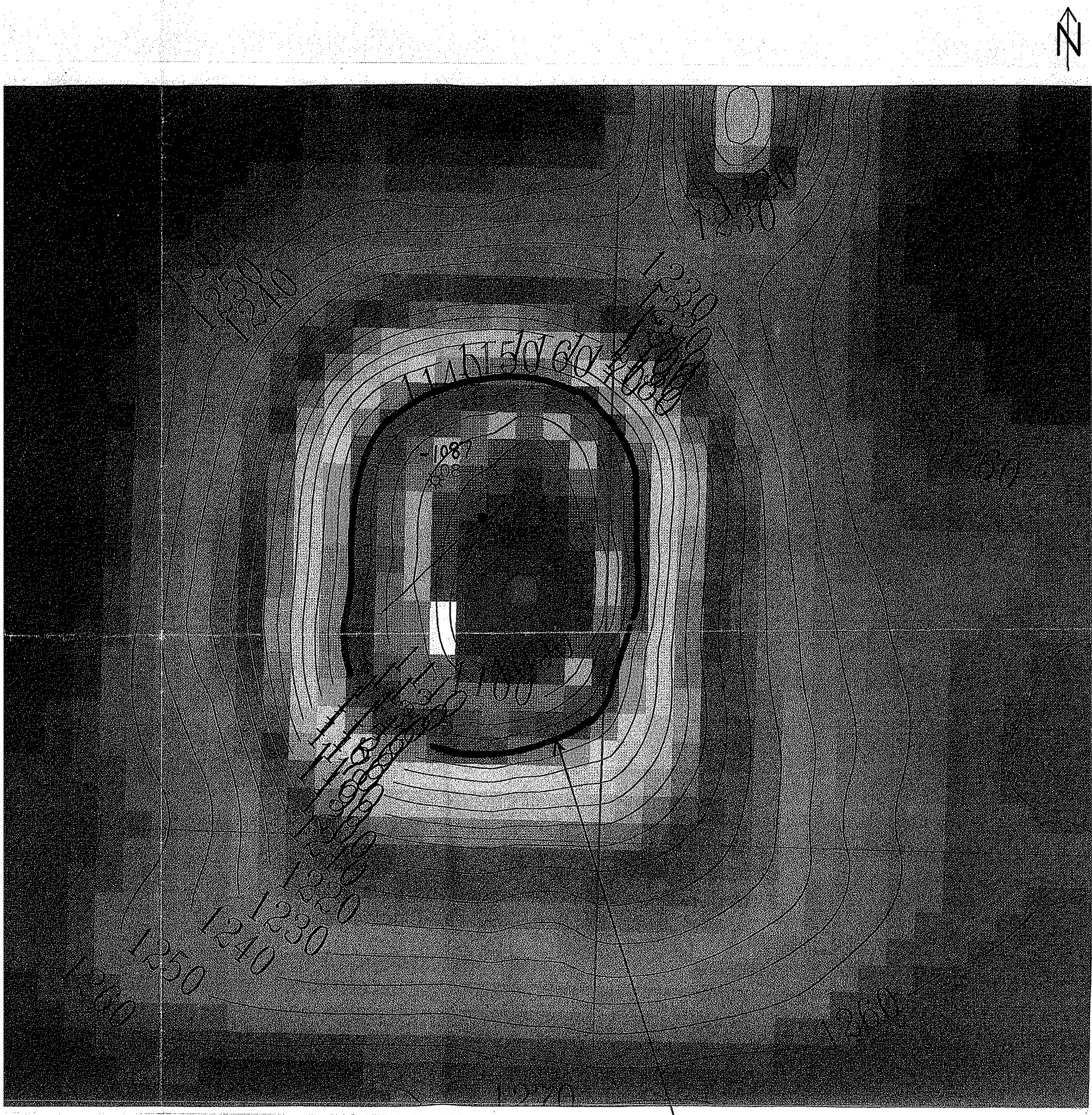
Zama Keg R. "F" Pool

Keg R. Net Oil Pay C.I.=10m

Map Software by IHS Energy
Vol. 14 No. 01, Jan 13 2004
(403) 770-4646

Author: L. Eslinger
Date: February 9, 2004
File: Larne.MAP
Scale: 1 : 5000

Scale 1:5000
0 Kilometers 0.2
0 Miles 0.14



56) Keg Depth

Keg Depth
Keg Depth

o/w • 1131

Figure 5

NET OIL PAY 44m

01-13-116-06W6
Zama KR F
Keg River Depth
CI = 10m / SS

0m 250m 500m

1cm. = 50 meters

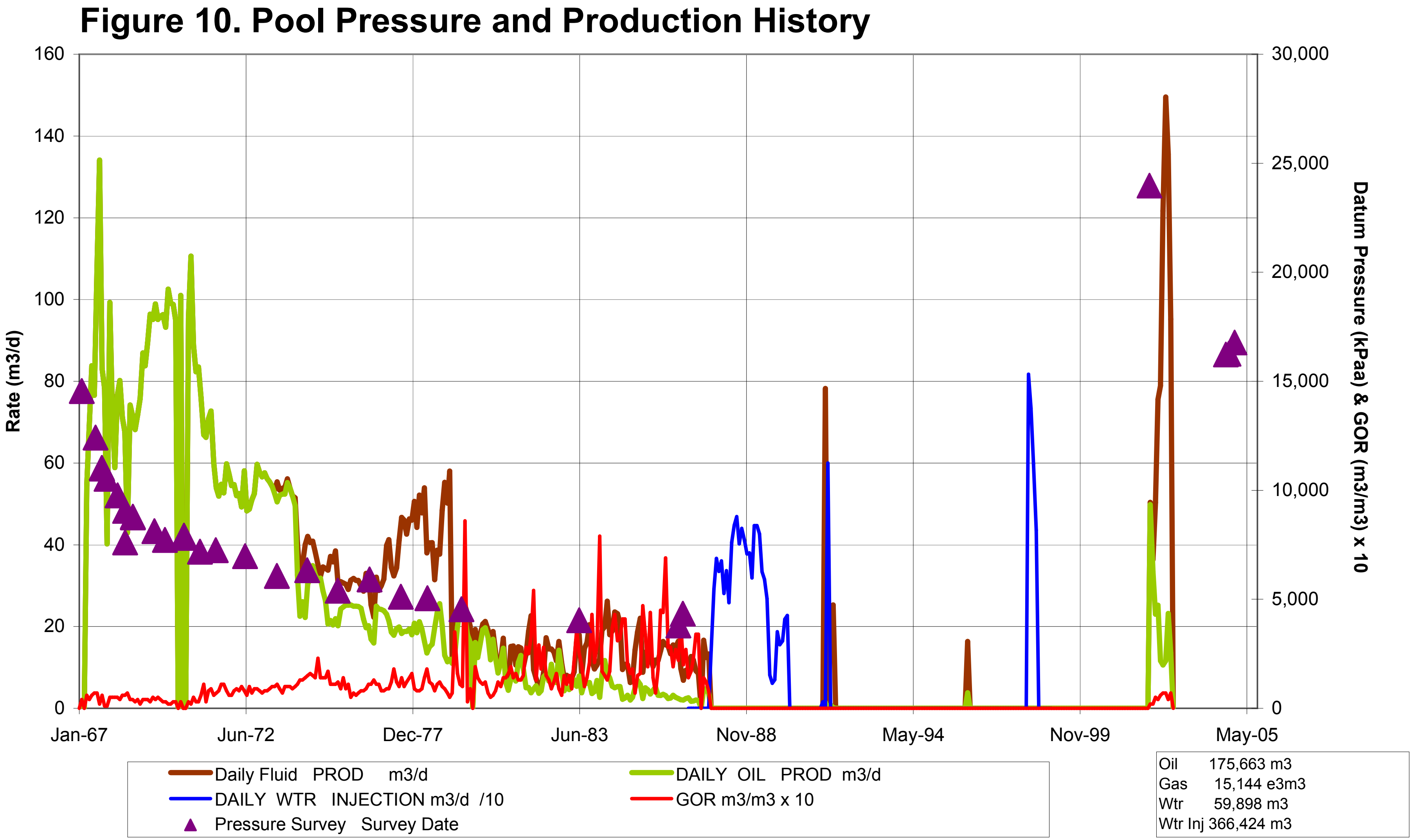
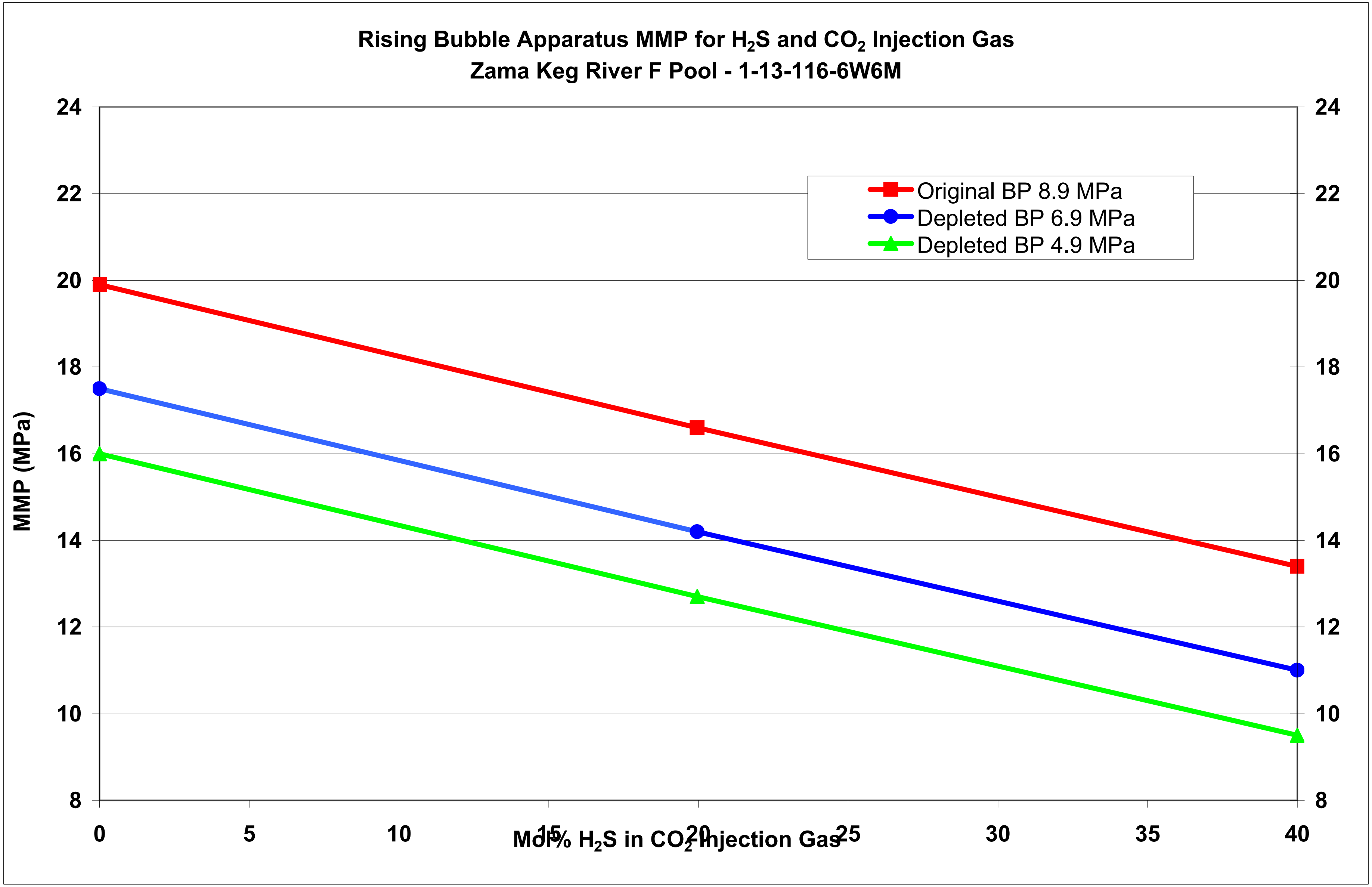


Figure 10. Pool Pressure and Production History
Rate (m3/d)
Datum Pressure (kPaa) & GOR (m3/m3) x 10
160
140
120
100
80
60
40
20
0
30,000
25,000
20,000
15,000
10,000
5,000
0
Jan-67
Jun-72
Dec-77
Jun-83
Nov-88
May-94
Nov-99
May-05
Daily Fluid PROD m3/d
DAILY OIL PROD m3/d
DAILY WTR INJECTION m3/d /10
GOR m3/m3 x 10
Pressure Survey Survey Date
Oil 175,663 m3
Gas 15,144 e3m3
Wtr 59,898 m3
Wtr Inj 366,424 m3


Rising Bubble Apparatus MMP for H_2S and CO_2 Injection Gas
Zama Keg River F Pool - 1-13-116-6W6M
MMP (MPa)
Mol% H_2S in CO_2 Injection Gas
Original BP 8.9 MPa
Depleted BP 6.9 MPa
Depleted BP 4.9 MPa
24
22
20
18
16
14
12
10
8
0
5
10
15
20
25
30
35
40

Analytical Model Based
on
Rainbow Keg River Miscible Flood - Late Breakthrough
Figure 14a and 14b

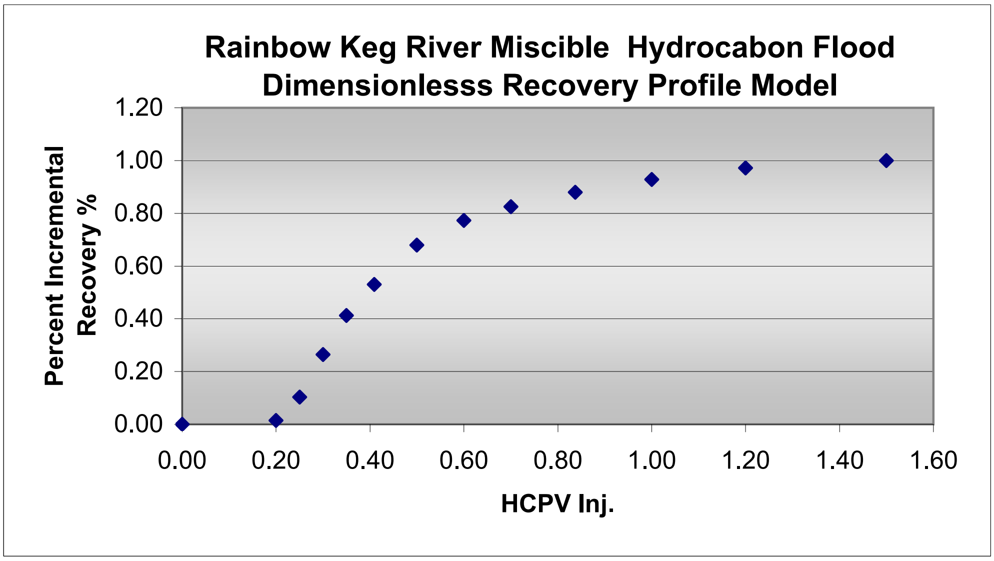


Figure 14a

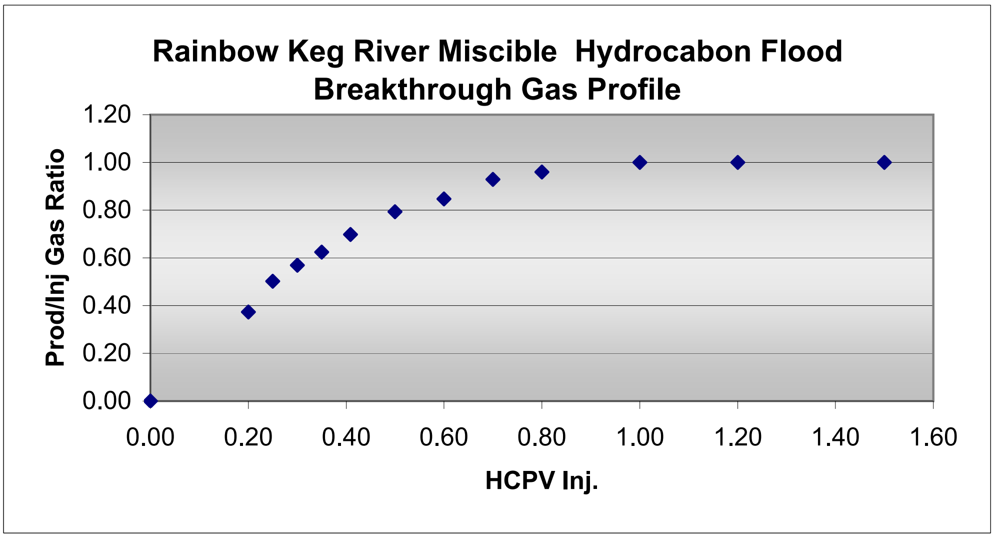


Figure 14b

Analytical Model Based
on
Rainbow Keg River Miscible Flood - Early Breakthrough
Figure 15a and 15b

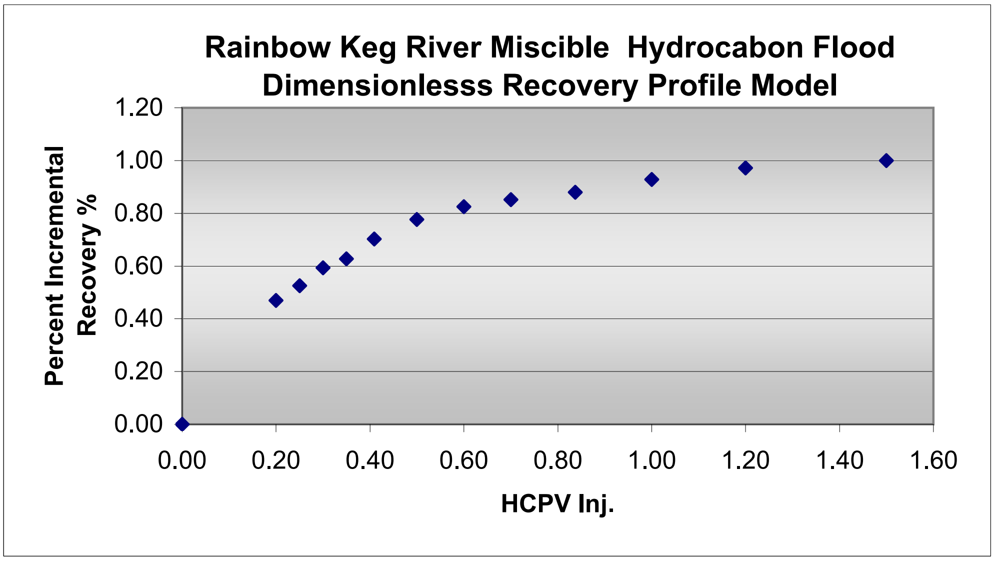


Figure 15a

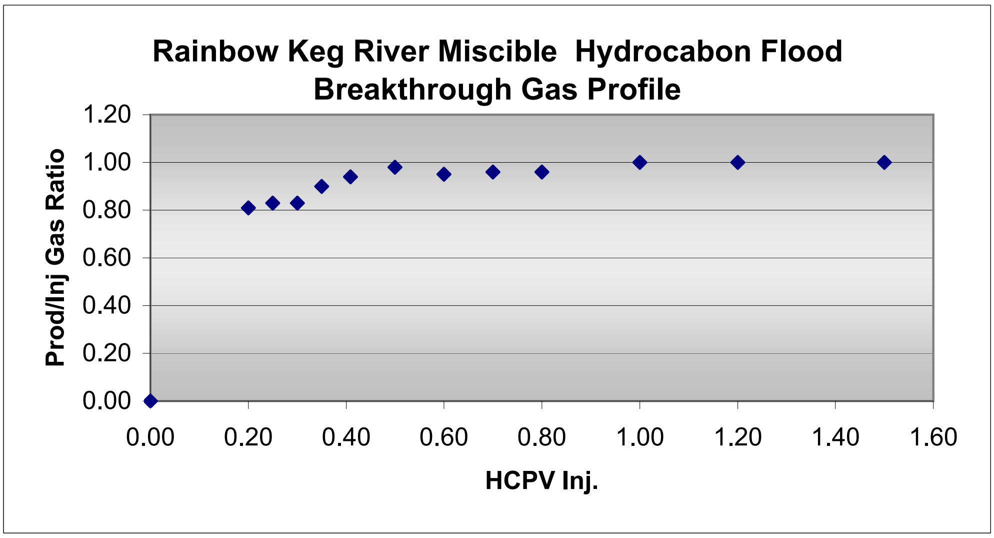


Figure 15b

Figure 16a
EOR Oil Rate
Keg River F Recovery Profile - Early Breakthrough

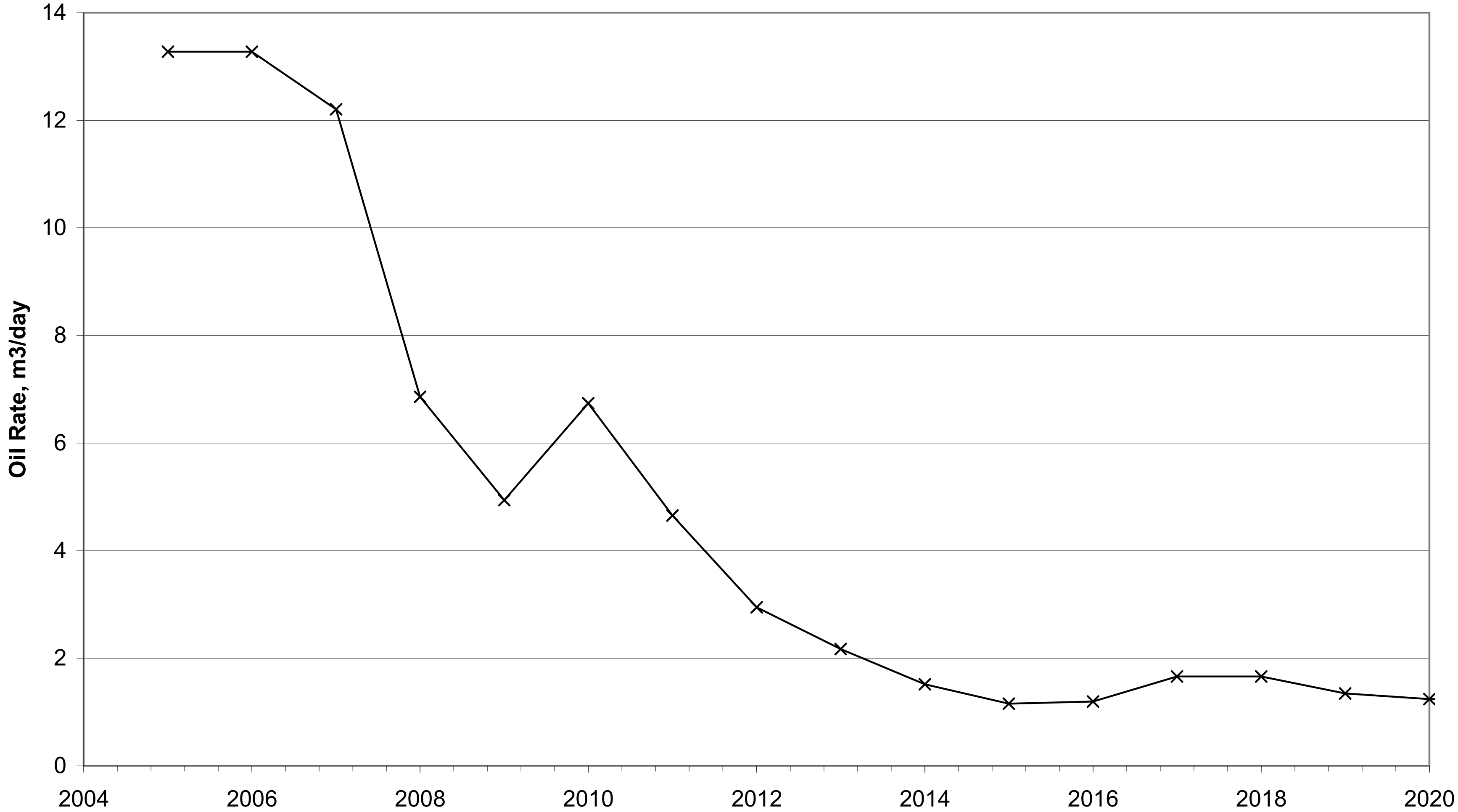
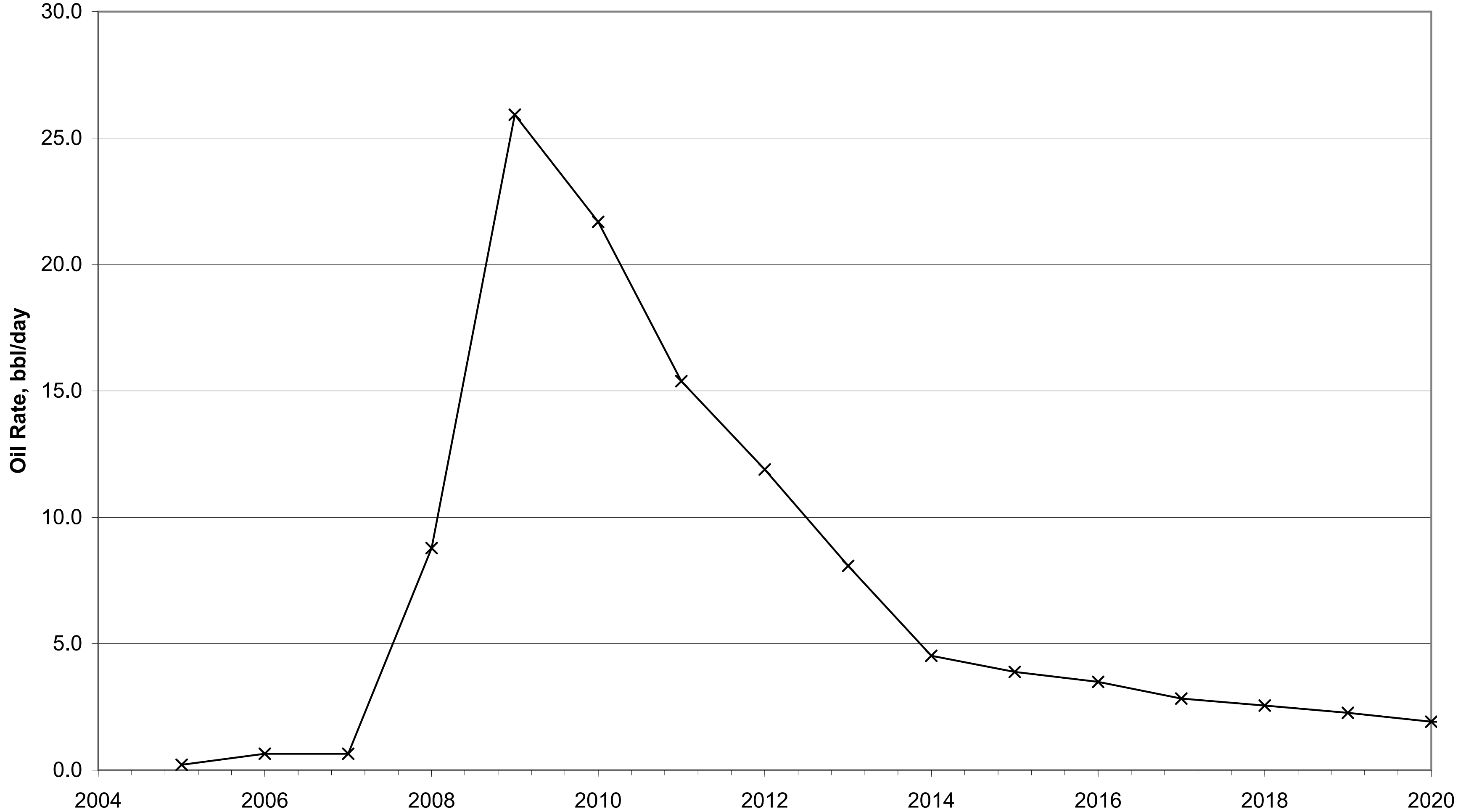


Figure 16b
EOR Oil Rate
Keg River F Recovery Profile - Late Breakthrough



EUB Alberta Energy and Utilities Board

Guide 65 -Schedule 1
Resources Applications

1: REGISTRATION

Month 08 Day 09 Year 2004 Applicant's File Number 01-13-116-6W6

EUB USE ONLY	
Registration Number: ______	Registration Date: Month ___ Day ___ Year ___

Company Name Apache Canada Ltd. Company Code OJL8

Contact Person (N/A ☐) Nimchuk (Last Name) Doug (First Name)

Telephone 403-261-1271 Fax 403-261-1273

E-Mail Address Doug.nimchuk@apachecorp.com

Consultant (N/A ☐) CalPetra Research and Consulting Inc. (Company Name) AOP2 (Consultant Code)

Consultant Contact Person Lavoie (Last Name) Robert G. (First Name)

Telephone (403) 862-9798 Fax (403) 261-1273

E-Mail Address Rob.lavoie@apachecorp.com

2: BASIC INFORMATION REQUIREMENTS

1. Field, Strike Area, and Pool

Field code No./Name	Strike Area Name	Pool code No./Name
0997 / Zama	Zama	0788006 / Keg River F

2. What is the ownership basis on which you make this application?
100% owner and operator of the subject pool

3. Have you completed the notification requirements? Yes ☐ No ☒

4a. Do you need EUB assistance to complete the notification requirements? Yes ☐ No ☒ If yes, please supply details.
Apache has issued notifications to applicable land owners. Apache will forward all correspondence related to these notices to the EUB. Although notifications are required, injection wells DO NOT have critical sour status until injection commences.

4b. Are there outstanding concerns? Yes ☐ No ☒

5. Does your injectant contain hydrogen sulphide (H_2S)? Yes ☒ No ☐

5a. If Yes, is a new emergency response plan (ERP) needed, or does an existing ERP need updating? Yes ☒ No ☐

5b. If No, state why not ______

5c. If Yes, supply details The updated ERP will be provided to the EUB concerning acid gas injection proposed for this project

(continued)

Company Name Apache Canada Ltd.

5d. Have you conducted notification for ERP purposes to all potentially affected parties? Yes ☒ No ☐

5e. If Yes, are there any outstanding concerns?
No.

6. Are you applying to amend an existing approval or order? Yes ☐ No ☒

6a. If Yes, what is the existing approval or order number? ____________

6b. Is the name of the approval holder current? Yes ☒ No ☐

3: TYPE OF APPLICATIONS

1. What types of resources applications are you submitting at this time?

UNIT 1 - EQUITY

☐ Rateable Take (1.1)
☐ Common Purchaser (1.2)
☐ Common Carrier (1.3)
☐ Common Processor (1.4)
☐ Common Pooling (1.5)
☐ Special Spacing (1.6)

UNIT 2 - CONSERVATION

☒ Enhanced Recovery Scheme (2.1)
☐ Enhanced Oil Recovery Project (2.2)
☐ Enhanced Recovery Recognition Good Production Practice (2.3)
☐ Concurrent Production (2.4)
☐ Pool Delineation and Ultimate Reserves (2.5)

UNIT 3 - PRODUCTION CONTROL

☐ Commingled Production (3.1)
☐ Good Production Practice (Primary Depletion Pool) (3.2.2)
☐ Gas-Oil Ratio Penalty Relief (3.2.3)
☐ Special Maximum Rate Limitation (3.2.4)
☐ Gas Allowable (3.3)

UNIT 4 - DISPOSAL/STORAGE

☐ Disposal (Class I-IV (4.1)
☐ Acid Gas Disposal (4.2)
☐ Underground Gas Storage (4.3)

UNIT 5 - CORPORATE CHANGES

☐ Change in Name of Approval Holder (5.1)
☐ Change of Holder of Approval (5.2)

4: FUTURE APPLICATIONS

1. Do you plan to submit subsequent applications associated with the present applications to the EUB within six months?
Yes ☒ No ☐

2. If Yes, state what types and when you plan to submit these applications.
The Guide 51applications for this Enhanced Recovery Scheme will be submitted as soon as the wells have been completed for injection service.

Note: Remember to file three copies of the application package, including Schedule 1, unless otherwise specified in individual units of this guide.

SUBMIT APPLICATIONS TO:

Alberta Energy and Utilities Board
Resources Applications Group
640 - 5 Avenue SW
Calgary, Alberta T2P 3G4

SUITE 1000 / 700 – 9th AVENUE S.W. / CALGARY, ALBERTA, CANADA T2P 3V4

Apache CANADA LTD.

(403) 261-1200
FAX (403) 263-1200

November 9, 2004

Alberta Energy and Utilities Board
Resource Applications Group
640 – 5th Ave. S.W.
Calgary, AB
T2P 3G4

Attention: Joe McIntosh
Resources Applications Group

RE: Zama – Keg River F Pool – Enhanced Oil Recovery Scheme Application
Addendum – Reservoir Abandonment Plans
Application No. 1356043

Apache Canada Ltd. ("Apache") has recently requested approval to implement an Enhance Oil Recovery (EOR) Miscible Flood project in the subject pool. During the review of Apache's application a question was raised regarding the pressure at which this pool (and other similar pools) will be abandoned.

Background Information

Apache's latest pressure measurement conducted for the 01-13-116-6W6M well at reservoir datum is 16,225 kPa. This pressure is 1,672 kPa above the earliest pressure measurement (original reservoir pressure) of 14,553 kPa taken on February 28, 1967, prior to start of production.

As can be seen in Table 1 and Figure 1, the minimum miscibility pressure for the planned acid gas miscible flood, as measured in a Rising Bubble Apparatus (RBA) at the Saskatchewan Research Council (SRC), ranges from 13.4 to 19.9 MPa for H_2S concentrations ranging from 40% down to 0% respectively (the balance being CO_2).

The planned injectant acid gas H2S composition is anticipated to range between a minimum of 25% and maximum of 40% with an average of 32% H_2S. However, due to the presence of methane and nitrogen impurities in the plant effluent (1.2% C_1 and 1.2% N_2), it is likely that the MMP will be about 800 to 1,000 kPa higher than for pure H_2S and CO_2 components. Given a worst case scenario of an average 25% H_2S solvent injection stream, the MMP would be 15.8 MPa plus a contingency for impurities of 1,000 MPa. Therefore the required MMP with a safety factor is 16.8 MPa or 17,000 mPa as was suggested in the subject Guide 65 Application. Apache seeks to operate this pool at a pressure of 17.5 MPa to ensure miscibility is achieved even at the lowest range of H_2S composition.

Given that the reservoir pressure is currently below this target, acid gas will be injected with no (or low) production until the desired reservoir pressure has been achieved. Once the 17.5 MPa target range is achieved, a voidage replacement of 1.0 will be maintained until the end of the flood. The flood is currently anticipated to require about 8 to 10 years to reach its economic limit. When the economic limit for the F Pool is reached, acid gas will be diverted to other prospective acid gas miscible flood pools in the area.

Abandonment Pressure Question

Given the discussion above, Apache wishes to maintain a target pressure regime of 17.5 MPa for the F Pool. **Apache is committed to de-pressurizing this pool to an acceptable pressure level** upon reaching the economic limit of the miscible flood, and given continued future concerns over H_2S containment in this pool. In order to define a specific time commitment for this, Apache commits to blow down of the pool if no production is taken from the F pool production well (0/08-13-116-6W6) over a period of 3 years. This will be done by either continued production of acid gas (with re-injection in a disposal well or other miscible flood project) or continued production of high water-cut fluids until the reservoir pressure is reduced to an acceptable level as determined by the EUB.

We look forward to further discussion concerning this project. If you have any further information requirements related to this application please contact either Rob Lavoie, 303-8584 or Doug Nimchuk, 261-1271.

Yours Truly,

Mike Thorson
Manager, Reservoir Engineeing – Apache Canada Ltd.

Table 1: Summary of RBA MMP Measurements of Apache-Zama Recombined Oil with CO_2 + H_2S Mixtures

Recombined Oil Sample Well	1-13-116-6 W6M	11-25-116-6 W6M
Temperature (°C)	71	76
Injection Gas Composition (% H_2S)*	**MMP (MPa)**	**MMP (MPa)**
0	19.9	21.3
20	16.6	19.0
40	13.4	16.9

* Balance is CO_2

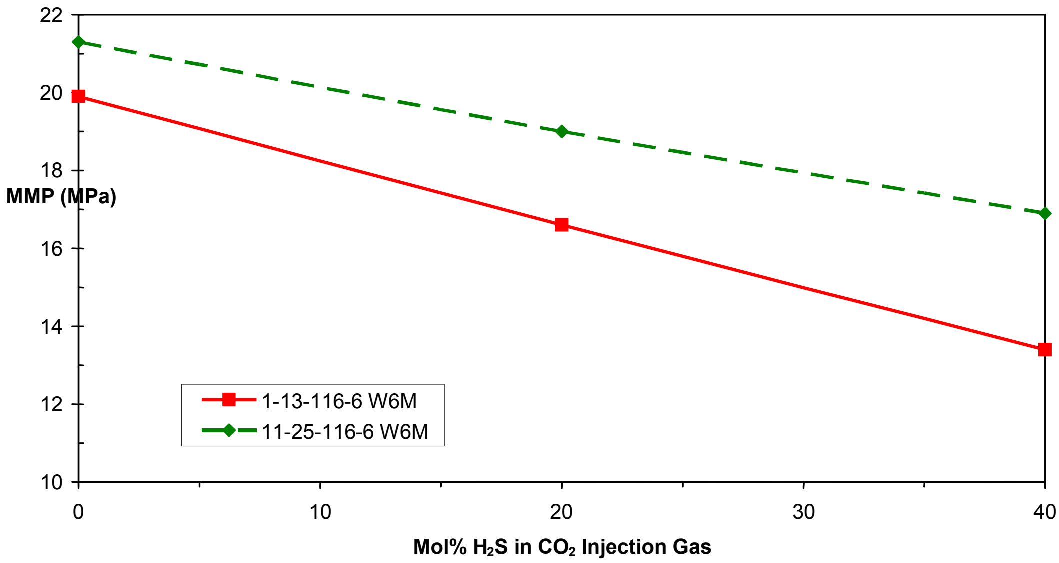


Figure 1: Rising Bubble Apparatus MMP for H_2S + CO_2 Injection Gas Mixtures with Zama Recombined Oils

SUITE 1000 / 700 – 9th AVENUE S.W. / CALGARY, ALBERTA, CANADA T2P 3V4

CANADA LTD.

(403) 261-1200
FAX (403) 263-1200

December 9, 2004

Alberta Energy and Utilities Board
Resource Applications Group
640 – 5th Ave. S.W.
Calgary, AB
T2P 3G4

Attention: Joe McIntosh
Resources Applications Group

RE: Zama – Keg River F Pool – Enhanced Oil Recovery Scheme Application
Additional Information Request of December 9, 2004
Guide 65 Application No. 1356043

Apache Canada Ltd. ("Apache") has recently requested approval to implement an Enhance Oil Recovery (EOR) Miscible Flood project in the subject pool, **Resource Application No. 1356043**. This addendum addresses a request for further information by the EUB, dated December 9, 2004. This letter will be referred to as the Information Request (IR) letter. Each requested information item will be referred to by the numbering in the IR.

IR 1:

As was indicated in our previous addendum letter of November 9, 2004, Apache remains committed to de-pressuring the F Pool at the end of the productive life of the current applied for scheme. Given that two wells currently exist for this pool, either one of these wells could be used for the purpose of de-pressuring the pool after wells have been suspended for a 3 year period. Apache will weigh the merits of conducting the de-pressuring earlier (than the 3 year wait discussed above) if there is a risk that wells may need re-drilling. The need for additional wells or re-working of existing wells to achieve the desired de-pressure operation will be assessed at that time. However, Apache commits to de-pressuring the reservoir to the original reservoir pressure of 14,553 kPa at the conclusion of the scheme in the timing stated above using the most appropriate method available at that time.

Further to this discussion is the issue of managing the location of the residual oil column. Apache will monitor the situation and take action to prevent movement of the oil column to a position below the original oil-water contact. **It would not be in Apache's best interest to allow this kind of movement to take place since any mobile oil remaining in the residual oil column would become inaccessible to be produced through the existing well completion.**

Based on 3-D seismic interpretations, the location of the structural spill point below the original oil water contact of 1131 mSS is 1230 mSS which provides 99 meters of possible movement of the oil-water contact before over-filling would occur. As stated above, it would not be in Apache's best interest to allow displacement of a remaining oil column to a depth this far below the original oil-water contact and Apache would not allow this to occur. Apache will be monitoring the residual location of the oil column and ensuring that the reservoir pressure balance between the gas cap and the oil zone are not such that this kind of over displacement would occur.

IR 2:

ERP notifications and approvals for the 00/01-13 and 02/01-13 wells are currently in process. Land notifications have been issued for these wells but delays in locating the area liaisons have delayed receiving the required notification approvals. Once these have been obtained the EPR applications will be sent to the EUB for approval. The primary wellhead components are PSL III compliant as required for critical sour gas wells. All documentation to this effect has or will be submitted as part of Apache's critical sour gas well application process.

The new EPR approval for injection and production lines will allow for up to 60% H_2S at a surface pressure of 14,890 kPa. Again, these EPR approvals are waiting on area liaison notification approvals. Please refer to Attachment 1 for pipeline and facility licensing information pertaining to maximum operating pressure and maximum H2S content.

IR 3:

As for IR2, ERP approvals are in progress for both the 00/01-13 and 02/01-13 wells. Apache will have these ERP documents into the EUB before the year end.

Yours Sincerely,

Mike Thorson
Manager, Reservoir Engineering – Apache Canada Ltd.

ENHANCED OIL RECOVERY
Approval No. 10328

MADE at the City of Calgary, in the Province of Alberta, on 18th day of August 2005.	ALBERTA ENERGY AND UTILITIES BOARD

The Alberta Energy and Utilities Board, pursuant to the Oil and Gas Conservation Act, chapter O-6 of the Revised Statutes of Alberta, 2000, orders as follows:

1) The scheme of Apache Canada Ltd. (hereinafter called “the Operator”) for enhanced recovery of oil by miscible displacement using hydrogen sulphide (H2S) and carbon dioxide (CO2) injection in that part of the **Zama Keg River F Pool** outlined in Appendix A of the approval, as described in

   a) Application No. 1356043,

   is approved, subject to the terms and conditions herein contained.

2) For the purposes of this approval “miscible fluid” means gas that contains:

   a) a mixture of at least 0.970 mole fraction of H2S and CO2, with the remainder composed of other natural gas components,

   b) an H2S content not less than 0.25 mole fraction and not more than 0.40 mole fraction at any time, and

   c) an average H2S content not less than 0.32 mole fraction based on a 3 month rolling average.

3) The miscible fluid, as identified in clause 2, is to be injected into the subject pool through the well(s) with the following unique identifier(s):

   <u>Class III</u>

   00/01-13-116-06W6/0

   The class of fluid is described in EUB Guide 51.

4) The injection of miscible fluid may commence in the well(s) referred to in clause 3 once the EUB has confirmed in writing that EUB Guide 51 requirements have been met.

5) The Operator shall conduct injection, to that part of the subject pool referred to in Appendix A, in accordance with the following requirements:

EUB Alberta Energy and Utilities Board

Calgary Office 640 – 5 Avenue SW Calgary, Alberta Canada T2P 3G4 Tel 403 297-8311 Fax 403 297-7336

August 18, 2005

Doug Nimchuk
Apache Canada Ltd.
Suite 1000, 700 – 9 Avenue SW
Calgary AB T2P 3V4

Dear Mr. Nimchuk:

ZAMA KEG RIVER F POOL
ENHANCED OIL RECOVERY SCHEME
APPLICATION NO. 1356043
APPROVAL NO. 10328

The Alberta Energy and Utilities Board (EUB) has considered your application, dated July 31, 2004, and related submissions requesting approval to implement a new scheme for enhanced oil recovery by miscible displacement using hydrogen sulphide and carbon dioxide in the Zama Keg River F Pool. Your application has been granted subject to the conditions detailed in Approval No. 10328, which is enclosed for this purpose.

The EUB will defer recognizing any enhanced recovery reserves for this scheme until actual scheme performance indicates that such reserves are being recovered. In this regard, the annual performance review presentations for the scheme required as part of the subject approval and in accordance with EUB *IL 96-02: Progress Report Requirements for Miscible Flood Schemes* will be or particular interest in determining the success of acid gas injection in recovering incremental reserves in this particular reservoir situation.

Questions on this matter should be directed to Joe McIntosh at 297-8415.

Yours truly,

Tom Byrnes, P. Eng.
Staff Reservoir Engineering Specialist
Resources Applications

JM
Enclosure

a) production, without injection, shall initially occur until the average reservoir pressure is between 14 450 kiloPascals (gauge) and 13 700 kiloPascals(gauge). Miscible fluid shall then be injected in sufficient volumes to maintain the average reservoir pressure between 13 700 kiloPascals (gauge) and 14 450 kiloPascals (gauge),

b) the reservoir pressure shall be monitored by conducting a bottomhole pressure test every 6 months, with the first test commencing by February 1, 2006,

c) wellhead injection pressure shall not exceed 8 000 kiloPascals (gauge) at any time,

d) the injection well shall be monitored in accordance with EUB IL 94-2 and subsequent amendments,

e) the representative composition of the injected miscible fluid shall be determined on a bi-weekly basis, and the representative composition of the produced gas shall be determined on a monthly basis,

f) once miscible fluid injection begins, the Slave Point Formation in the 00/08-13-116-06W6 well shall be monitored for H2S and CO2 by collecting fluid samples from the perforated Slave Point interval in this well on a bi-monthly basis and analyzing these samples for H2S and CO2 content. If there is any indication of increased H2S or CO2 contents, the Operator shall immediately inform the EUB Resources Applications Group,

g) the pressure in the tubing/casing annulus of the injection well shall be monitored on a daily basis. The Operator shall immediately inform the EUB Operations Group if a tubing, casing, or packer failure is suspected, or if any H2S or CO2 is detected at the injection well's surface casing vent,

h) packer isolation tests at the injection well shall be conducted on an annual basis and the results submitted electronically to the EUB by September 1 of each year, and appropriate corrosion protection shall be implemented,

f) injection operations shall be suspended immediately if any operational equipment, monitoring equipment, or safety devices fail that would compromise environmental protection or the safe operation of the scheme,

g) if acid gas breakthrough occurs before any appreciable oil is produced from the Keg River formation in the 03/01-13-116-06W6 well, the Operator shall immediately inform the EUB Resources Applications Group and provide the details of its plans for modifying scheme operations and making the corresponding amendments to this approval,

h) the abandonment of any well, whether an injector or producer, shall not proceed until the Operator has applied and received approval for its abandonment program from the EUB Operations Group,

6) The Operator shall be subject to the two-part reporting process for miscible floods outlined in EUB IL 96-2: Progress Report Requirements for Miscible Flood Schemes. In addition to the

base reporting requirements specified in IL 96-2, the following annual data submission requirements shall apply:

a) a summary of all workovers done on the injection and producing wells including, but not limited to, the reason for the workovers and the results of the workovers,

b) a discussion of changes in equipment and operations,

c) a discussion of changes in the performance of the scheme including, but not limited to, identification of problems, remedial action taken, and results of remedial action on scheme performance,

d) a discussion of the overall performance of the scheme, including where the injected miscible fluid may have swept the reservoir and to what extent an oil bank may have formed,

e) results and evaluation of all monitoring done during the reporting period including but not limited to: pressure surveys, corrosion protection, fluid analyses, logs and any other data collected that would help in determining the success of the scheme,

f) a table(s) showing the following injection data for each month of the reporting period:

   i) mole fraction of H_2S in the injected miscible fluid,
   ii) mole fraction of CO_2 in the injected miscible fluid,
   iii) three month rolling average mole fraction of H_2S in the injected miscible fluid,
   iv) volume of H_2S injected at standard conditions,
   v) volume of CO_2 injected at standard conditions,
   vi) volume of miscible fluid injected at standard conditions,
   vii) formation volume factor of miscible fluid injected,
   viii) volume of miscible fluid injected at reservoir conditions,
   ix) hours on injection,
   x) average daily miscible fluid injection rate at standard conditions,
   xi) maximum wellhead injection pressure (MWHIP),
   xii) corresponding wellhead injection temperature when MWHIP was measured,
   xiii) average wellhead injection pressure, and
   xiv) average wellhead injection temperature,

g) a table(s) showing the following production data for each month of the reporting period, with free gas defined as the produced gas exclusive of any solution gas from the produced oil:

   i) average producing oil rate at standard conditions,
   ii) volume of oil produced at standard conditions,
   iii) formation volume factor of oil produced,
   iv) volume of oil produced at reservoir conditions,
   v) average producing gas rate at standard conditions,
   vi) volume of gas produced at standard conditions,

vii) calculated volume of free gas produced at standard conditions,
viii) average composition of gas produced,
ix) calculated average composition of free gas produced,
x) formation volume factor of free gas produced,
xi) volume of free gas produced at reservoir conditions,
xii) average producing water rate at standard conditions,
xiii) volume of water produced at standard conditions,
xiv) formation volume factor of water produced,
xv) volume of water produced at reservoir conditions,
xvi) average producing gas/oil ratio at standard conditions, and
xvii) average producing water/oil ratio at standard conditions,

h) a table showing the following voidage calculation data at reservoir conditions for each month of the reporting period:

i) volume of miscible fluid injected,
ii) volume of oil produced,
iii) volume of free gas produced,
iv) volume of water produced, and
v) estimated, or actual measured, average reservoir pressure,

i) a table showing the calculated net tonnes of sulphur and carbon dioxide injected into the pool by the scheme on a monthly and cumulative basis, and

j) a plot showing the following monthly average data at standard conditions versus time:

i) miscible fluid injection rate,
ii) producing oil rate,
iii) producing gas rate,
iv) producing water rate,
v) producing gas/oil ratio, and
vi) producing water/oil ratio,

with the plot displaying the scheme on an ongoing basis and not just for the reporting period.

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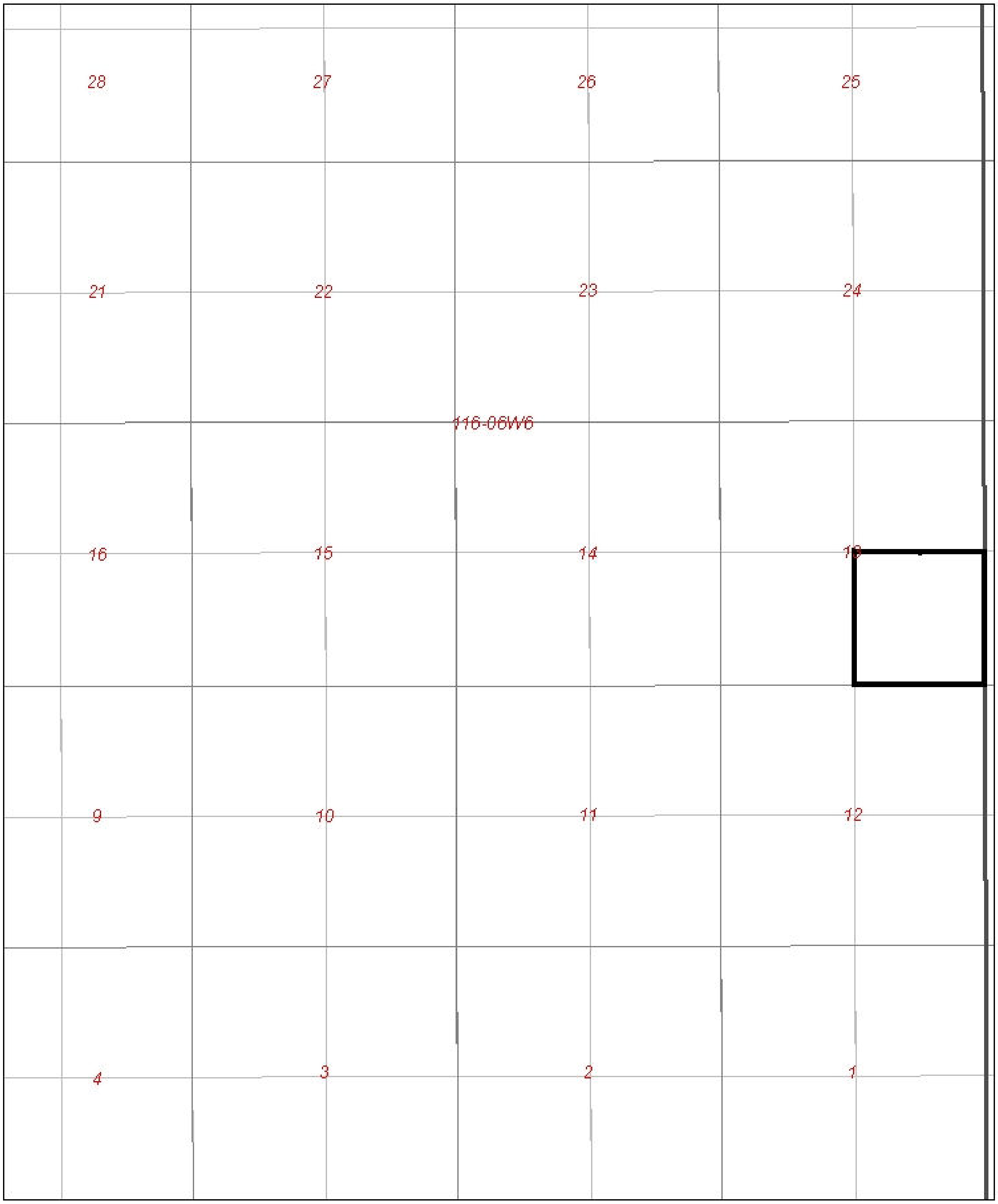

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ZAMA KEG RIVER F POOL
APPENDIX A TO APPROVAL NO. 10328

Added
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DIRECTIVE 065 AMENDMENT APPLICATION

FOR

ACID GAS ENHANCED RECOVERY SCHEME

IN

ZAMA KEG RIVER F POOL

APPROVAL No. 10328A

Prepared by:

Apache Canada Ltd.

October 2007

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1 General

1.1 Proposed Acid Gas Enhanced Recovery Scheme Amendment

In accordance with Section 39(1)(a) of the Oil and Gas Conservation Act, Apache Canada Ltd. ("the Operator"), the operator of Enhanced Oil Recovery Approval No. 10328A, hereby applies to amend the approval for the following changes to the specified operating conditions:

a) the composition of the solvent acid gas

b) the average operating pressure of the miscible flood

c) the frequency of injected miscible fluid sampling

1.2 Current Approval Specifics

Enhanced Oil Recovery Approval No. 10328A specifies the following Clauses:

2) For the purposes of this approval "miscible fluid" means gas that contains:

   a) a mixture of at least 0.970 mole fraction of H_2S and CO_2, with the reminder composed of other natural gas components,

   b) an H_2S content not less than 0.20 mole fraction and not more than 0.40 mole fraction at any time, and

   c) an average H_2S content not less than 0.23 mole fraction based on a 3 month rolling average.

5) The Operator shall conduct injection, to that part of the subject pool referred to in Appendix A, in accordance with the following requirements:

   a) production, without injection, shall initially occur until the average reservoir pressure is between 15500 kiloPascals (gauge) and 14000 kiloPascals (gauge). Miscible fluid shall then be injected in sufficient volumes to maintain the average reservoir pressure between 14000 kiloPascals (gauge) and 15500 kiloPascals (gauge),

   c) wellhead injection pressure shall not exceed 8000 kiloPascals (gauge) at any time.

   e) the representative composition of the injected miscible fluid shall be determined on a bi-weekly basis, and the representative composition of the produced gas shall be determined on a monthly basis.

1.3 Proposed Amendment Specifics

The Operator proposes the following changes to the Clauses:

2) ***For the purposes of this approval "miscible fluid" means a gas mixture with the following physical properties:***

   a) ***a minimum cumulative pseudo critical temperature (cumulative from start of acid gas injection) of 310° K,***

   b) ***a H_2S content not more than 0.40 mole fraction at any time***.

   c) ***A methane content not more than 0.11 mole fraction based on a 3 month rolling average***

5) The miscible fluid injected to that part of the subject pool outlined in Appendix A

   a) Production, without injection, shall initially occur until the average reservoir pressure is between ***16500*** kiloPascals (gauge) and ***14500*** kiloPascals (gauge). Miscible fluid shall then be injected in sufficient volumes to maintain the average reservoir pressure between ***14500*** kiloPascals (gauge) and ***16500*** kiloPascals (gauge),

   c) wellhead injection pressure shall not exceed 8 000 kiloPascals (gauge) at any time.

   d) the representative composition of the injected miscible fluid and the representative composition of produced gas shall be determined on a ***monthly*** basis.

2 Basic Data

2.1 Approval Area

The Approval No. 10328A covers the entire Zama Keg River F Pool which is in the SE/4 of Section 13-116-06W6. This amendment is not seeking any changes to the original approval area. A map showing the pool boundary, the approval area and the notification area can be found in Figure 1.

2.2 Pool Reserves and Recovery

The Operator is not proposing any changes to the original oil-in-place (OOIP) or incremental recovery estimates in this amendment application. The following table summarizes the various recoveries and factors as stated in the original enhanced recovery application:

Source of OOIP	*EUB*	*Apache*
OOIP Estimate (10^3m^3)	546.0	344.0
Current Oil Recovery (10^3m^3)	176.3	176.3
Current Oil Recovery Factor (%)	32.3	51.2
Incremental Miscible Recovery Estimate (10^3m^3)		29.2 to 44.0
Incremental Miscible Recovery Estimate (%)		8.5 to 12.8

A tabulation of reservoir parameters is provided as Table 1 while reserves and production forecasts are provided as Table 2 and Figure 2.

3 Proposed Amendment Details

3.1 Background

Apache is currently operating a total of 5 acid gas miscible flood schemes and one acid gas disposal well. The production responses of the Operator's first two acid gas enhanced recovery (ER) schemes, Zama Keg River G2G and Zama Keg River Z3Z Pools, have exceeded our expectation and predictions. Figures 3 and 4 show the production/injection histories of the two pools respectively. While this is a good news story, it does have some unexpected implications to other acid gas miscible floods that will be using the associated solution gas stream from these existing ER schemes as part of the solvent.

In order to understand the issues, one has to understand the production facilities. Production from the pools with ER is sent to a high pressure separator at the Zama processing complex through dedicated high pressure production flow lines. The associated solution gas is separated from the oil and is sent into the acid gas stream from Plant #2 to become the solvent for re-injection into other pools with miscible ER schemes. Figure 5 is a map of the facilities, wells, flow lines, pools and their spatial relations of one to another. Figure 6 is a diagram showing only the pools with miscible ER schemes and how they are connected to the central facilities. The blue dash rectangle in the center of the diagram represents the Zama processing complex. Even though the diagram is not drawn to scale, the pools identified north of the complex are indeed to the north of it. Likewise, the pools drawn to the south of the complex are located south of the processing facilities.

In 2006, acid gas from Plant #3 was used as solvent to the ER schemes to the south of the complex while acid gas from Plant #2 was combined with the associated solution gas from the high pressure separator to become solvent for ER schemes to the north of the complex.

3.2 Changes to Solvent Composition

Figure 7 shows the hydrocarbon content in the acid gas solvent stream used for injection into the ER schemes to the north of the Zama complex. It consisted of the acid gas from Plant #2 and the associated solution gas from Zama Keg River G2G Pool and Zama Keg River Z3Z Pool. There was a definite up trend with hydrocarbon exceeding 3% for approximately half of year. Figure 8 shows the hydrocarbon content in the acid gas solvent stream used for injection into the ER schemes to the south of the Zama complex. The solvent is strictly acid gas from Plant #3. The plot shows that the hydrocarbon content to be essentially flat throughout 2006 and below 3%. Besides a slight variation in hydrocarbon content of acid gas between Plant #2 and Plant #3, the only other difference between the solvent stream going north of the plant and the stream going south was the associated solution gas from the high pressure separator.

3.3 Implication to Miscibility

As more acid gas ER schemes start to show production responses, a larger volume of associated solution gas is expected and the hydrocarbon content of the combined injection stream may continue to increase as the proportion of the associated solution gas increases. This increase in hydrocarbon content in the solvent would affect the conditions in which miscibility with reservoir oil could be achieved. Apache has conducted an extensive study on the effect using an Equation of State (EOS) model.

3.4 Expected Range of Solvent Composition

Tables 3, 4 and 5 tabulate a range of expected solvent compositions that were used in the EOS study. The tables show the blending of acid gas stream from a plant at the complex with an associated solution gas stream at different blending ratios. Both the composition of the plant gas and the solution gas streams vary in each case.

Table 3 shows a scenario of the blending of a plant gas and a solution gas with the lowest hydrocarbon content. The blending ratio is bracketed by the plant gas at the one end and the recycle solution gas at the other. Four other blending ratios of plant gas and recycle gas were used for the intermediate ranges: 5:1, 3:1, 1:1 and 0.6:1. The resulting compositions are listed in blue.

Table 4 shows the resulting composition of a scenario of blending an average plant gas and recycle gas composition in 2006.

Table 5 shows the resulting composition of blending a plant gas with the lowest H_2S content and a recycle gas with the highest hydrocarbon content, consisting of very high methane composition. This represents possibly the worst case scenario for miscibility.

The EOS study, therefore, examined solvent compositions ranging from having 40% H_2S and 0.5% hydrocarbon on one end to 23% H_2S and 16% hydrocarbon (all methane) on the other.

3.5 Equation of State Calibration

Apache has invested significant effort into modeling Zama reservoir oil with an EOS model. This EOS was used to predict miscibility. Before any prediction was made, the EOS model was tuned on the characterization of enhanced recovery lab studies from Zama Keg River F, Zama Keg River G2G and Zama Keg River NNN Pools. Figure 9 shows the lab result of a slim tube recovery using an acid gas blend and oil from Zama Keg River NNN Pool. It also shows the prediction of an uncharacterized EOS and one of a characterized EOS. The characterized EOS recovery prediction virtually matches that of the lab result.

3.6 Implication to Minimum Miscibility Pressure

Figure 10 shows the result of simulated slim tube experiments with an acid gas that consists of 23% H_2S, 75.75% CO_2, 1% C_1 and 0.25% N_2. This acid gas composition represents the lowest H_2S composition going forward from the Zama gas plants. The figure shows the result with original oil and depleted oil. The results show a range of minimum miscibility pressures (MMP) from 12,500 to 17,000 kPa. The two EOS models represent the range of uncertainty in the binary interaction coefficients used in PVT matches.

3.7 Minimum Miscibility Pressure and Pseudo Critical Temperature

Additional simulated slim tube studies were done with the different solvent compositions as detailed in Tables 3, 4 and 5. The result is presented in Figure 11 where MMP is plotted against the Pseudo Critical Temperatures (T_{pc}) of each of the solvents. The plot illustrates the relationship between MMP and the T_{pc} of the acid gas solvents.

Instead of showing the result of all the blends of plant gas and solution gas, Figure 11 shows all the cases of each of the three scenarios. This study uses a recombined original oil with a bubble point (P_b) of 8,890 kPa.

The green shaded area in Figure 11 shows the currently proposed amendment request operating pressure range of 14,000 to 15,500 kPa for the Zama Keg River F Pool ER scheme that is currently before the board. The blue shaded area in the figure shows the range of T_{pc} (314.0 to 326.8 ºK) of the acid gas solvent injected into the scheme in 2006.

The EOS study clearly shows that the currently approved operating pressure range is inadequate to achieve miscibility for solvents with higher expected hydrocarbon content. Similarly, should the hydrocarbon content in the solvent increase beyond the level seen in 2006, the T_{pc} of the acid gas solvents is expected to be lower.

Apache's estimate of the lowest quality acid gas solvent over the life of the ER project to be consisted of 23% H2S, 60.5% CO2, 11.4% C1, 0.2% N2 and 2.9% intermediate hydrocarbons which has a T_{pc} of 310 ºK. A solvent with this character would achieve miscibility with the Zama Keg River F recombined original oil at an operating pressure range of 14,500 to 16,500 kPa.

Figures 12 and 13 show the T_{pc} of the acid gas solvent available for ER schemes north of the Zama complex and south of the Zama complex respectively in 2006.

3.8 Operating Pressure & Formation Fracture Pressure

The proposed operating pressure range of 14,500 to 16,500 kPa is above the original reservoir pressure of 14,447 kPa. Apache presents the step-rate injectivity test results from three Zama Keg River wells nearby: 00/11-25-116-06W6, 00/02-02-117-06W6 and 00/01-13-116-06W6 in Figure 14. None of the step-rate result shows a change of slope. Therefore, no formation fracture pressure was observed. The highest observed wellhead injection pressure in these tests was 12,000 kPa. At a nominal depth of 1,500 mKB and an injected fluid density of 1,100 kg/m^3, the bottomhole pressure is approximately 28,000 kPa. The Directive 051 allows 90% of the fracture or the highest observed pressure, whichever is less, we can, therefore, inject at a maximum downhole pressure of 25,200 kPa. The minimum wellhead pressure that will produce a downhole pressure of 25,200 will occur when the tubing contains the densest fluid. This will occur when the injection gas stream is made up of 100% plant gas. Therefore, with an average acid gas solvent density of 907 kg/m^3, this maximum downhole pressure translates into a maximum wellhead pressure of 12,265 kPa. The current Directive 051 approved maximum wellhead injection pressure is 8,000 kPa. An amendment to the D 51 Maximum Well Head Pressure will be made to match this proposed D 65 amendment.

3.9 Cap Rock Integrity

In order to ensure there is containment of the acid gas solvent within the Keg River reef, Apache undertook a study of the competency of the cap rock. The study used mercury injection to measure the capillary pressure in core plugs from the Keg River cap rock which was then used to determine the threshold entry pressure (Reference 1). Using mercury (the non-wetting phase) to displace air (the wetting phase); the 5 core plugs yielded threshold pressures ranging from 82,400 to 308,900 kPa with an average value of 157,000 kPa. The calculated permeability to air ranges from 1.59 10^{-9} to 7.95 10^{-9} millidarcy (md) and gave a harmonic average permeability of 3.7 10^{-9} md. Based on this harmonic average permeability, the mercury threshold pressure was calculated to be 215,955 kPa.

$$Threshold\_Press_{Acid\_Gas} = Threshold\_Press_{mercury}\left(\frac{IFT_{acid\_gas} \times \cos(\Theta_{acid\_gas})}{IFT_{mercury} \times \cos(\Theta_{mercury})}\right)$$

Where:

Threshold_Press	- Threshold Pressure
IFT	- Interfacial Tension
Θ	- Contact Angle
Acid_Gas	- Acid Gas displacing Brine
Mercury	- Mercury displacing Air

The equation above is used to calculate the threshold pressure of the cap rock with acid gas displacing brine.

Based on a measured IFT of 38 dynes/cm for the CO_2-brine interface, the threshold pressure for CO_2 was determined to be 22,400 kPa. The lab was unable to measure the contact angle and the IFT for the acid gas (H_2S/CO_2) solvent. The presence of H_2S is expected to result in a slightly lower IFT based on the higher solubility of H_2S in brine. An IFT of 30 dynes/cm is assumed for the solvent gas and the adjusted threshold pressure to acid gas is 17,700 kPa. This is the pressure differential required at the cap rock interface to initiate flow.

Since the average reservoir pressure is approximately 15,000 kPa and the threshold pressure is about 17,700 kPa, a pressure of approximately 32,700 kPa would be required to initiate flow. The actual flow rate would be dependant on the effective permeability through the thick low permeability cap rock layer, the viscosity of the acid gas, and the actual differential pressure for flow.

With a maximum permissible bottomhole injection pressure of 23,400 kPa (90% of fracture extension pressure) and based on a formation fracture gradient of 18 kPa/m, the solvent acid gas will be contained by the cap rock.

3.10 Other Changes to Ascertain Solvent Composition

As detailed in Section 3.1, the associated solution gas from the high pressure separator can currently be combined only with the acid gas from Plant #2 as solvent for the ER schemes to the north of the Zama complex. In order to increase operating flexibility to control solvent composition, Apache intends to make changes to the injection flow lines such that the associated solution gas from the high pressure separator can be diverted to be combined with acid gas from Plant #3 as shown in Figure 6.

4 Safety

Although the Operator proposes to operate the enhanced recovery scheme at a target average reservoir pressure between 14,500 to 16,500 kPa, Apache is committed to de-pressurize the pool pressure back down to the original reservoir pressure of 14,447 kPa upon reaching the economic limit of the miscible flood. Apache proposes to start pool de-pressurization within three years of suspension of the miscible flood by either one or both of the following:

1. production of acid gas from the top of the reef with re-injection into an acid gas disposal well or into other miscible flood enhanced recovery schemes
2. production of high watercut reservoir fluid from the base of the pinnacle reef

5 References

1. Core Laboratories, “Advanced Rock Properties Study for Pennzoil Canada Inc. – Co-enerco Zama 06-04-116-6W6M”, for Pennzoil Canada Inc., April 27, 1995, File Number: 52132-95-1017

Tables

RESERVOIR PARAMETERS

Pool: Zama Keg River F Pool

Reservoir Parameters			
Pi, Reservoir Pressure (initial)	14,447	kPag	EUB Reserves Database
P, Reservoir Pressure (current)	15,838	kPag	September 2004 Static Gradient Test
T, Reservoir Temperature	71.1	ºC	Reservoir Fluid Study
Boi, Oil Formation Volume Factor (initial)	1.183	Res. m^3/m^3	Reservoir Fluid Study
Bo, Oil Formation Volume Factor (current)	1.172	Res. m^3/m^3	Calculated
Bg, Gas Formation Volume Factor (current)	N/A	Res. m^3/m^3	Reservoir Fluid Study
Rs, Solution Gas Oil Ratio (initial)	50.3	m^3/m^3	Reservoir Fluid Study
Rs, Solution Gas Oil Ratio (current)	13.2	m^3/m^3	Calculated
Porosity	10%		Well Logs
Initial Water Saturation	15%		Well Logs
API Gravity	35.2	API	Reservoir Fluid Study

Zama Keg River F Recovery Rate Forecast
Early and Late Breakthrough Cases

Zama Keg River F Production Forecast - Early Break Through Case

Pool	ZKR F		Producer	00/01-13-116-06W6/00
OOIP	344	e3m3	Injector	03/01-13-116-06W6/00
HCPV	413	e3rm3		
Inj. Rate	30.2	e3m3/day		
Acid Gas Eg	0.32	e3m3/rm3		
Rs	52.0	m3/m3		
Ult. EOR%	8.5%			

Year	Injection Rate e3m3/day	Cum. Inj e3m3	Cum Inj. res m3	Cum Net Inj, e3m3	Cum Recy, e3m3	HCPVinj Frac.	Incremental Rec Frac.	Year Oil Rate m3/day	Year Water Rate m3/day	Solution Gas Rate e3m3/day	Prod. Gas Rate e3m3/day
2006	30.2	11025	34818	10731.0	293.9	0.08	0.0169	15.93	95.4	0.8	10.3
2007	30.2	22050	69636	21436.4	613.4	0.17	0.0338	15.93	79.5	0.8	20.6
2008	30.2	33075	104454	24126.7	8948.0	0.25	0.0451	10.68	79.5	0.6	25.1
2009	30.2	44100	139272	34513.9	9585.6	0.34	0.0527	7.19	79.5	0.4	26.6
2010	30.2	55124	174090	44844.9	10279.5	0.42	0.0607	7.56	79.5	0.4	28.6
2011	30.2	66149	208908	55465.7	10683.6	0.51	0.0665	5.43	79.5	0.3	29.6
2012	30.2	77174	243726	66718.6	10455.6	0.59	0.0699	3.25	79.5	0.2	28.8
2013	30.2	88199	278544	77678.9	10520.1	0.67	0.0720	2.00	79.5	0.1	28.9
2014	30.2	99224	313362	88669.0	10555.0	0.76	0.0737	1.52	79.5	0.1	29.0
2015	30.2	110249	348180	99598.2	10650.7	0.84	0.0752	1.43	79.5	0.1	29.3
2016	30.2	121274	382999	110448.1	10825.6	0.93	0.0773	2.00	79.5	0.1	29.8
2017	30.2	132299	417817	121310.3	10988.3	1.01	0.0793	1.93	79.5	0.1	30.2
2018	30.2	143323	452635	132326.9	10996.6	1.10	0.0809	1.49	79.5	0.1	30.2
2019	30.2	154348	487453	143351.8	10996.6	1.18	0.0825	1.49	79.5	0.1	30.2
2020	30.2	165373	522271	154364.3	11008.9	1.26	0.0834	0.84	79.5	0.0	30.2
2021	30.2	176398	557089	165385.3	11012.9	1.35	0.0840	0.63	79.5	0.0	30.2
2022	30.2	187423	591907	176410.2	11012.9	1.43	0.0847	0.63	79.5	0.0	30.2
2023	30.2	198448	626725	187435	11012.9	1.52	0.0854	0.63	79.5	0.0	30.2

Zama Keg River F Production Forecast - Late Break Through Case

Pool	ZKR F		Producer	00/01-13-116-06W6/00
OOIP	344	e3m3	Injector	03/01-13-116-06W6/00
HCPV	413	e3rm3		
Inj. Rate	30.2	e3m3/day		
Acid Gas Eg	0.32	e3m3/rm3		
Rs	52.0	m3/m3		
Ult. EOR%	12.8%			

Year	Injection Rate e3m3/day	Cum. Inj e3m3	Cum Inj. res m3	Cum Net Inj, e3m3	Cum Recy, e3m3	HCPVinj Frac.	Incremental Rec Frac.	Year Oil Rate m3/day	Year Water Rate m3/day	Solution Gas Rate e3m3/day	Prod. Gas Rate e3m3/day
2006	30.2	11025	34818	10879	146	0.08	0.001	0.76	95.4	0.0	4.7
2007	30.2	22050	69636	21757	293	0.17	0.002	0.76	94.6	0.0	9.5
2008	30.2	33075	104454	27727	5348	0.25	0.014	11.99	83.4	0.6	15.3
2009	30.2	44100	139272	37977	6123	0.34	0.048	31.60	63.8	1.6	18.4
2010	30.2	55124	174090	47692	7433	0.42	0.070	21.28	63.8	1.1	21.5
2011	30.2	66149	208908	57683	8467	0.51	0.088	16.28	63.8	0.8	24.0
2012	30.2	77174	243726	68076	9098	0.59	0.098	9.45	63.8	0.5	25.4
2013	30.2	88199	278544	78301	9898	0.67	0.104	5.79	63.8	0.3	27.4
2014	30.2	99224	313362	88867	10357	0.76	0.108	4.45	63.8	0.2	28.6
2015	30.2	110249	348180	99647	10602	0.84	0.113	4.01	63.8	0.2	29.3
2016	30.2	121274	382999	110467	10807	0.93	0.116	2.99	63.8	0.2	29.8
2017	30.2	132299	417817	121329	10970	1.01	0.119	2.89	63.8	0.2	30.2
2018	30.2	143323	452635	132341	10982	1.10	0.121	2.24	63.8	0.1	30.2
2019	30.2	154348	487453	143366	10982	1.18	0.124	2.24	63.8	0.1	30.2
2020	30.2	165373	522271	154372	11001	1.26	0.125	1.26	63.8	0.1	30.2
2021	30.2	176398	557089	165391	11007	1.35	0.126	0.95	63.8	0.0	30.2
2022	30.2	187423	591907	176416	11007	1.43	0.127	0.95	63.8	0.0	30.2
2023	30.2	198448	626725	187441	11007	1.52	0.128	0.95	63.8	0.0	30.2

Table 2

Zama Keg River F Pool
Acid Gas EOR Approval No. 10328A Amendment

Best Case for Miscibility (Lowest C1 in Recycle stream gas analysis (Z3Z Aug 11 2006), 40% H2S)								
	Stream 1	Stream 2	End Streams (Simulated Injection Gas Compositions)					
Component	Plant Gas	Recycled Gas	Gas Plant	5:1	3:1	1:1	0.6:1	Recycle
N2	0.16%	0.21%	0.16%	0.17%	0.17%	0.18%	0.19%	0.21%
H2S	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
CO2	59.34%	50.69%	59.34%	57.90%	57.18%	55.02%	53.93%	50.69%
C1	0.50%	4.90%	0.50%	1.23%	1.60%	2.70%	3.25%	4.90%
C2	0.00%	1.70%	0.00%	0.28%	0.43%	0.85%	1.06%	1.70%
C3	0.00%	1.30%	0.00%	0.22%	0.33%	0.65%	0.81%	1.30%
i-C4	0.00%	0.20%	0.00%	0.03%	0.05%	0.10%	0.13%	0.20%
n-C4	0.00%	0.40%	0.00%	0.07%	0.10%	0.20%	0.25%	0.40%
i-C5	0.00%	0.20%	0.00%	0.03%	0.05%	0.10%	0.13%	0.20%
n-C5	0.00%	0.20%	0.00%	0.03%	0.05%	0.10%	0.13%	0.20%
C6+	0.00%	0.20%	0.00%	0.03%	0.05%	0.10%	0.13%	0.20%
Total HC	0.50%	9.10%	0.50%	1.93%	2.65%	4.80%	5.88%	9.10%

Table 3

Zama Keg River RRR Pool
Acid Gas EOR Approval No. 105551 Amendment

Existing Operating Conditions (Average Recycle Gas and Plant Gas for 2006)									
	Stream 1	Stream 2	End Streams (Simulated Injection Gas Compositions)						
Component	Plant Gas	Recycled Gas	Gas Plant	5:1	3:1	1:1	0.6:1	Recycle	Max HC[1]
N2	0.16%	0.21%	0.16%	0.17%	0.17%	0.19%	0.19%	0.21%	0.21%
H2S	31.46%	23.88%	31.46%	30.20%	29.56%	27.67%	26.72%	23.88%	23.00%
CO2	67.83%	63.51%	67.83%	67.11%	66.75%	65.67%	65.13%	63.51%	60.55%
C1	0.49%	7.56%	0.49%	1.66%	2.25%	4.02%	4.90%	7.56%	11.40%
C2	0.02%	1.88%	0.02%	0.33%	0.48%	0.95%	1.18%	1.88%	1.88%
C3	0.02%	1.31%	0.02%	0.23%	0.34%	0.66%	0.82%	1.31%	1.31%
i-C4	0.00%	0.23%	0.00%	0.04%	0.06%	0.12%	0.15%	0.23%	0.23%
n-C4	0.01%	0.59%	0.01%	0.10%	0.15%	0.30%	0.37%	0.59%	0.59%
i-C5	0.01%	0.32%	0.01%	0.06%	0.08%	0.16%	0.20%	0.32%	0.32%
n-C5	0.01%	0.35%	0.01%	0.07%	0.10%	0.18%	0.23%	0.35%	0.35%
C6+	0.01%	0.16%	0.01%	0.04%	0.05%	0.09%	0.10%	0.16%	0.16%
Total HC	0.56%	12.40%	0.56%	2.53%	3.52%	6.48%	7.96%	12.40%	16.24%

[1] One final run was made with a composition having a Tcp = 310K

Zama Keg River F Pool
Acid Gas EOR Approval No. 10328A Amendment

Worst Case for Miscibility (Highest C1 in Recycle Stream Gas Analysis (Theoretical), 23% H2S)								
	Stream 1	Stream 2	End Streams (Simulated Injection Compositions)					
Component	Plant Gas	Recycled Gas	Gas Plant	5:1	3:1	1:1	0.6:1	Recycle
N2	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
H2S	23.00%	23.00%	23.00%	23.00%	23.00%	23.00%	23.00%	23.00%
CO2	75.94%	60.50%	75.94%	73.37%	72.08%	68.22%	66.29%	60.50%
C1	0.49%	16.00%	0.49%	3.07%	4.36%	8.24%	10.18%	16.00%
C2	0.02%	0.00%	0.02%	0.02%	0.01%	0.01%	0.01%	0.00%
C3	0.02%	0.00%	0.02%	0.01%	0.01%	0.01%	0.01%	0.00%
i-C4	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
n-C4	0.01%	0.00%	0.01%	0.01%	0.00%	0.00%	0.00%	0.00%
i-C5	0.01%	0.00%	0.01%	0.01%	0.00%	0.00%	0.00%	0.00%
n-C5	0.01%	0.00%	0.01%	0.01%	0.01%	0.00%	0.00%	0.00%
C6+	0.01%	0.00%	0.01%	0.01%	0.01%	0.01%	0.00%	0.00%
Total HC	0.56%	16.00%	0.56%	3.13%	4.42%	8.28%	10.21%	16.00%

Figures

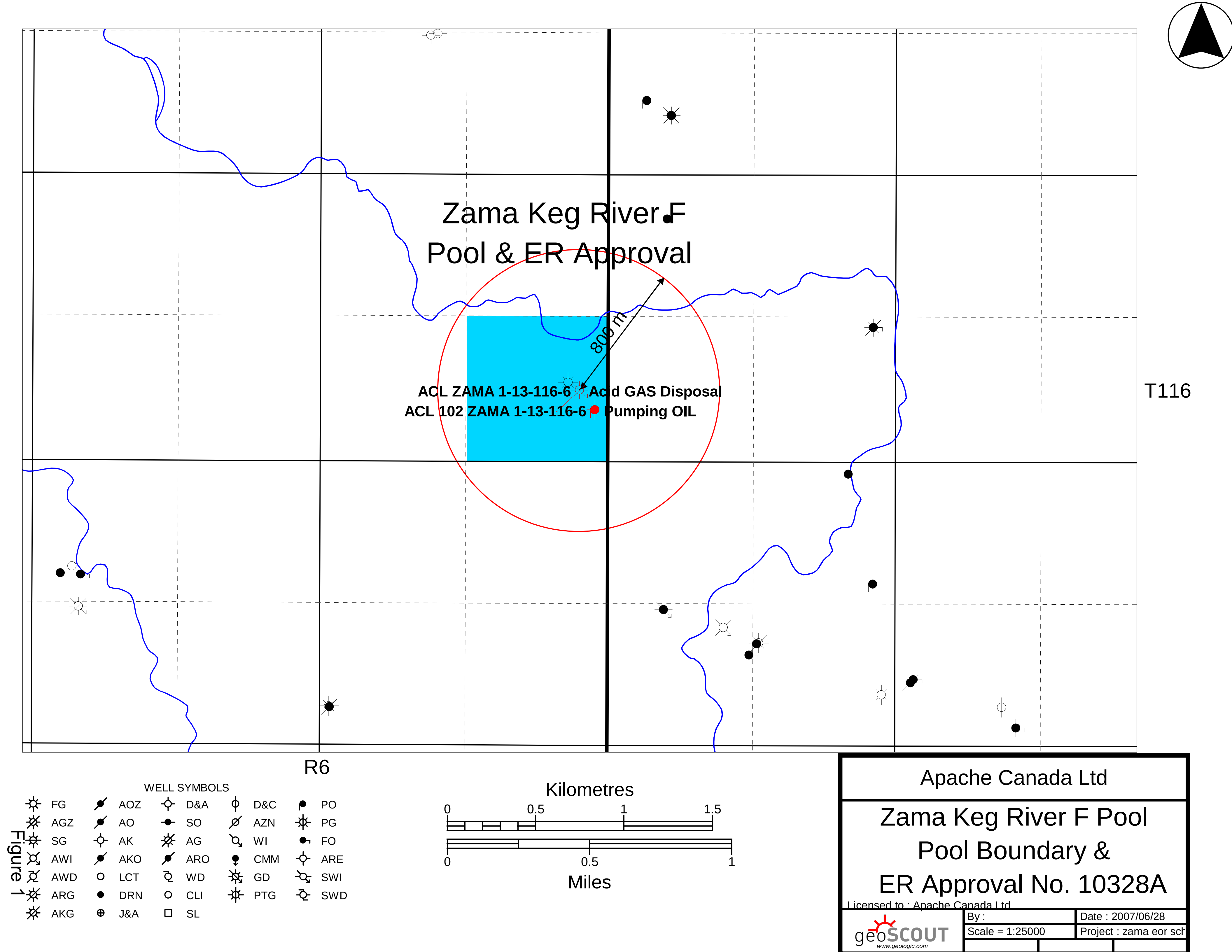
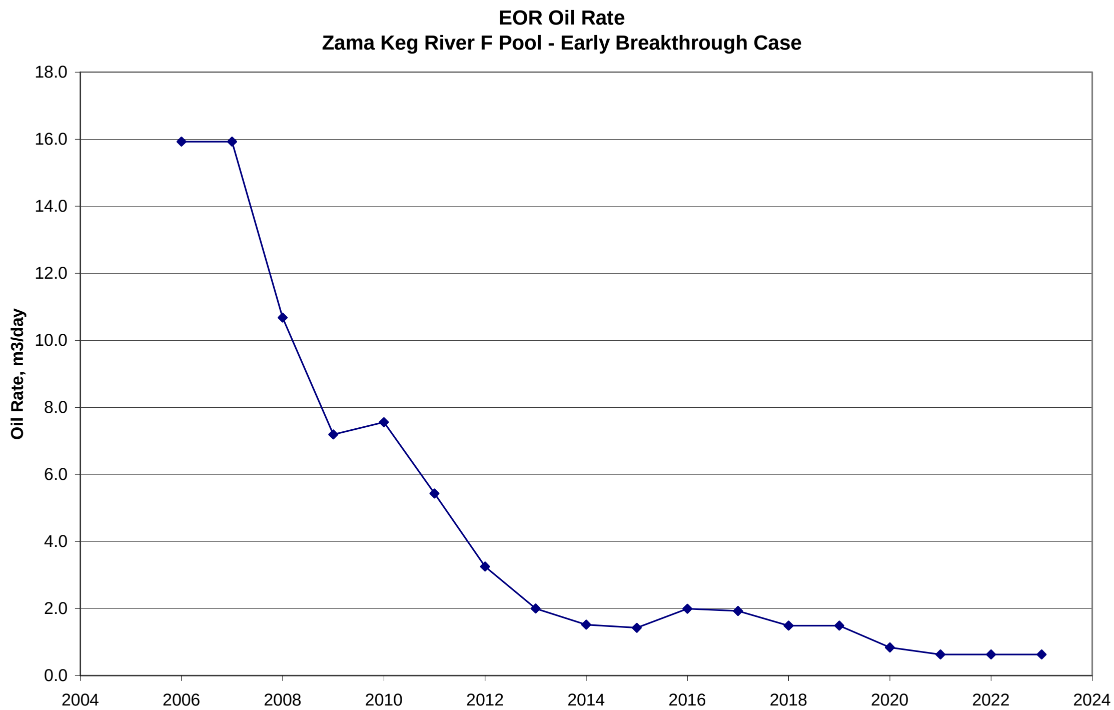

Zama Keg River F
Pool & ER Approval
800 m
ACL ZAMA 1-13-116-6 Acid GAS Disposal
ACL 102 ZAMA 1-13-116-6 Pumping OIL
T116
R6
WELL SYMBOLS
FG AGZ SG AWI AWD ARG AKG
AOZ AO AK AKO LCT DRN J&A
D&A SO AG ARO WD CLI SL
D&C AZN WI CMM GD PTG
PO PG FO ARE SWI SWD
Kilometres
0 0.5 1 1.5
0 0.5 1
Miles
Apache Canada Ltd
Zama Keg River F Pool
Pool Boundary &
ER Approval No. 10328A
Licensed to : Apache Canada Ltd
geoSCOUT
www.geologic.com
By :
Date : 2007/06/28
Scale = 1:25000
Project : zama eor sch

Figure 1

Zama Keg River F Recovery Rate Forecast

Early and Late Breakthrough Cases



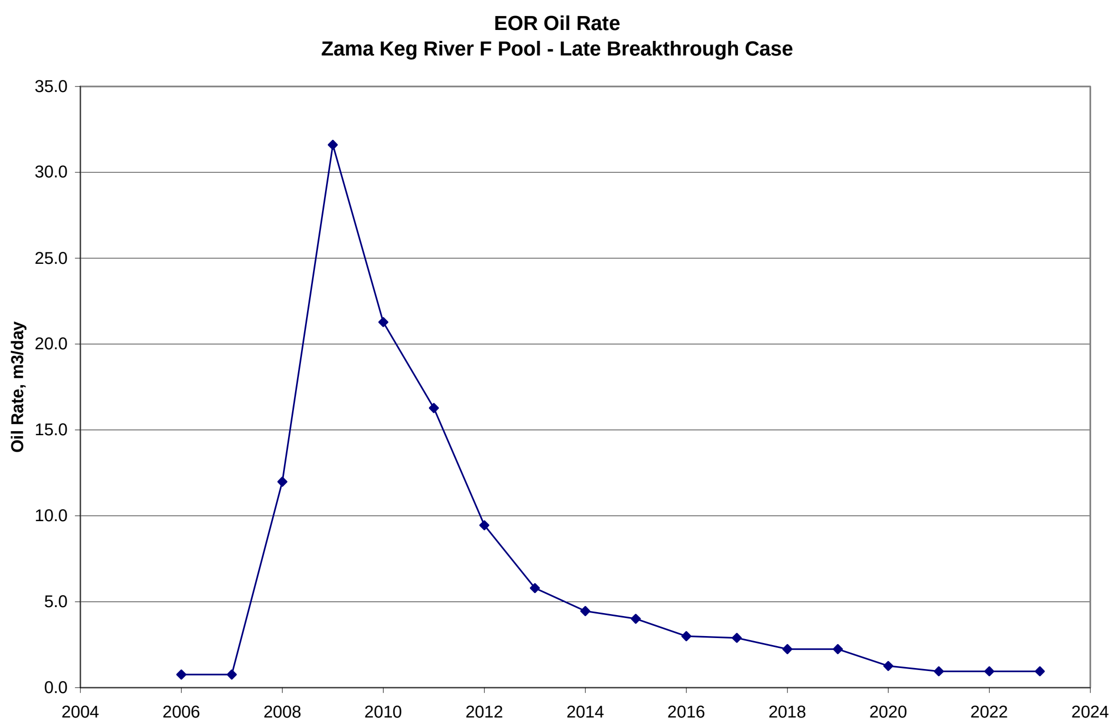


Figure 2

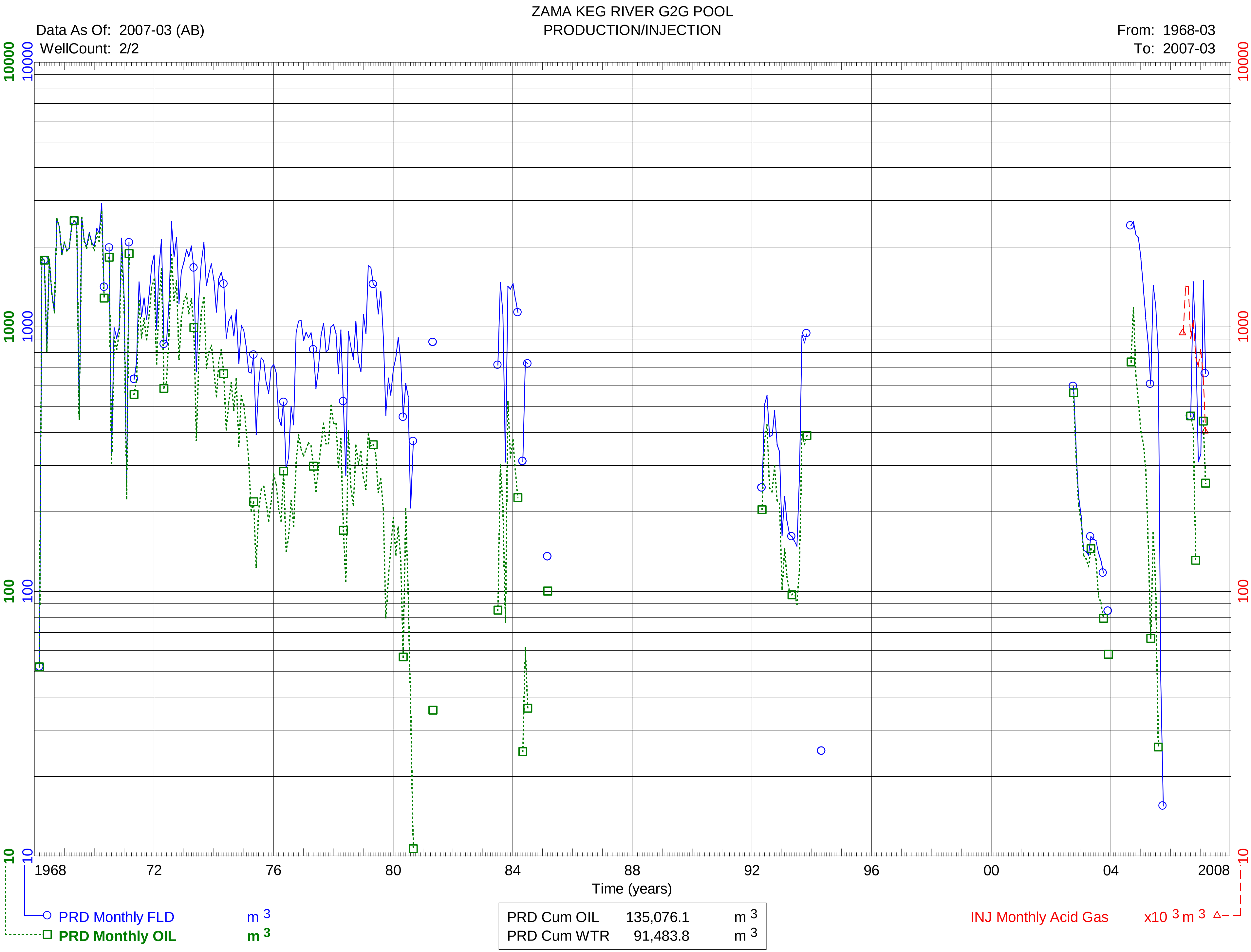


Figure 3

geoSCOUT www.geologic.com

Friday, May 25, 2007, 09:32 AM

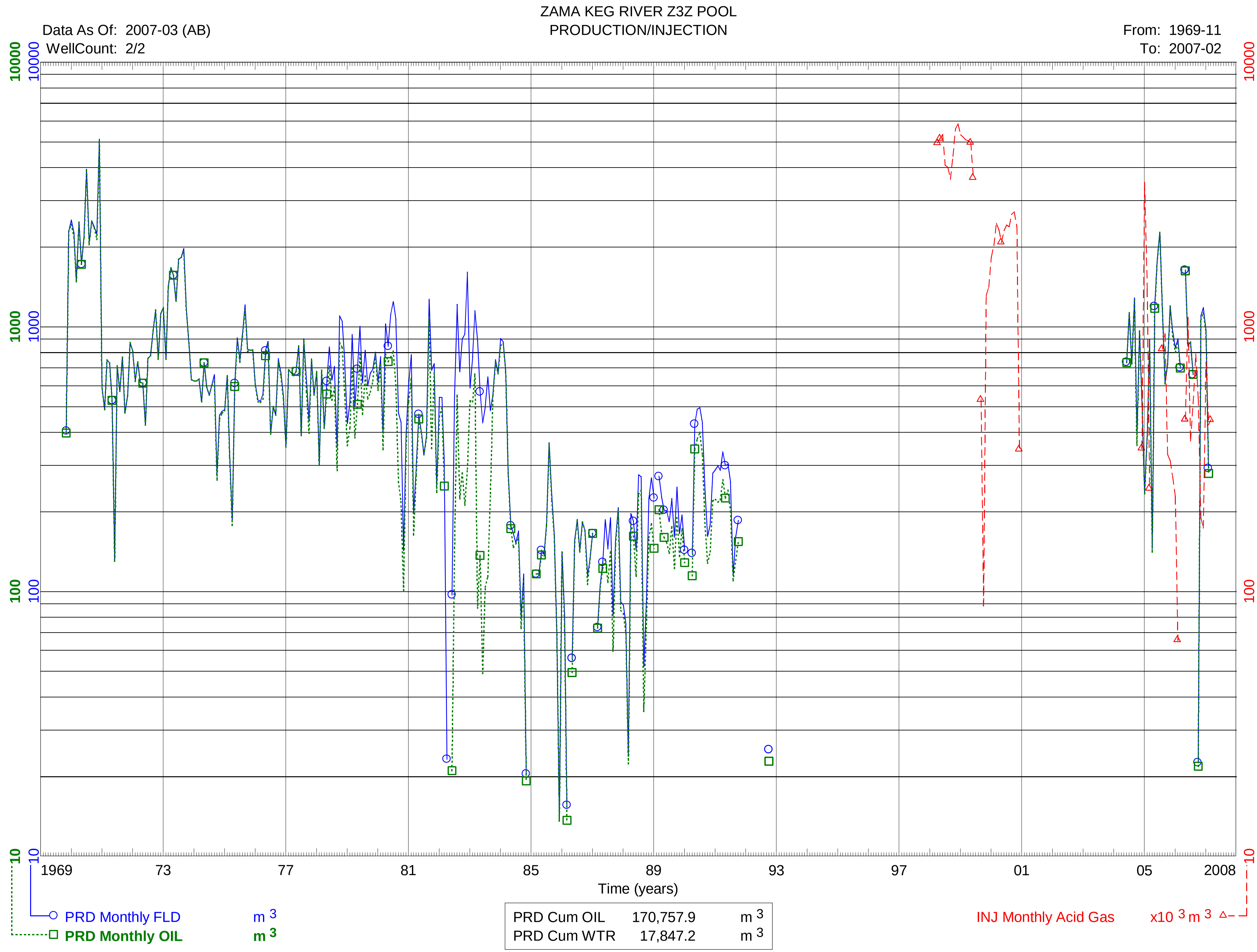


Figure 4

geoSCOUT www.geologic.com

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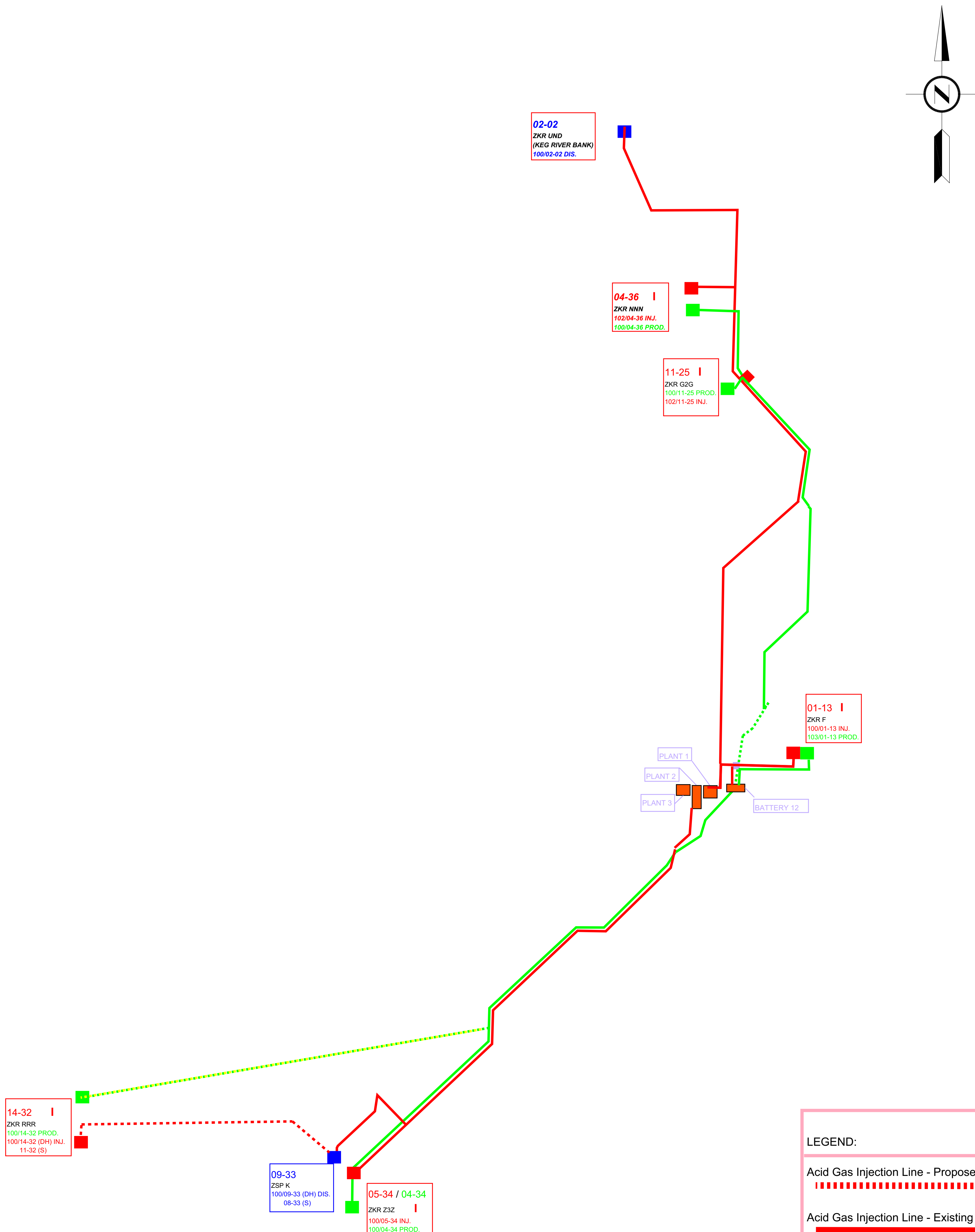


Inset Map:

LEGEND:

Acid Gas Injection Line - Proposed

Acid Gas Injection Line - Existing

Acid Gas Injection Line - Proposed Re-Use of Existing

Production Line - Proposed

Production Line - Existing

Production Line - Proposed Re-Use of Existing

Injection Well

Riser

Production Well

Plant / Battery 12

Disposal Well

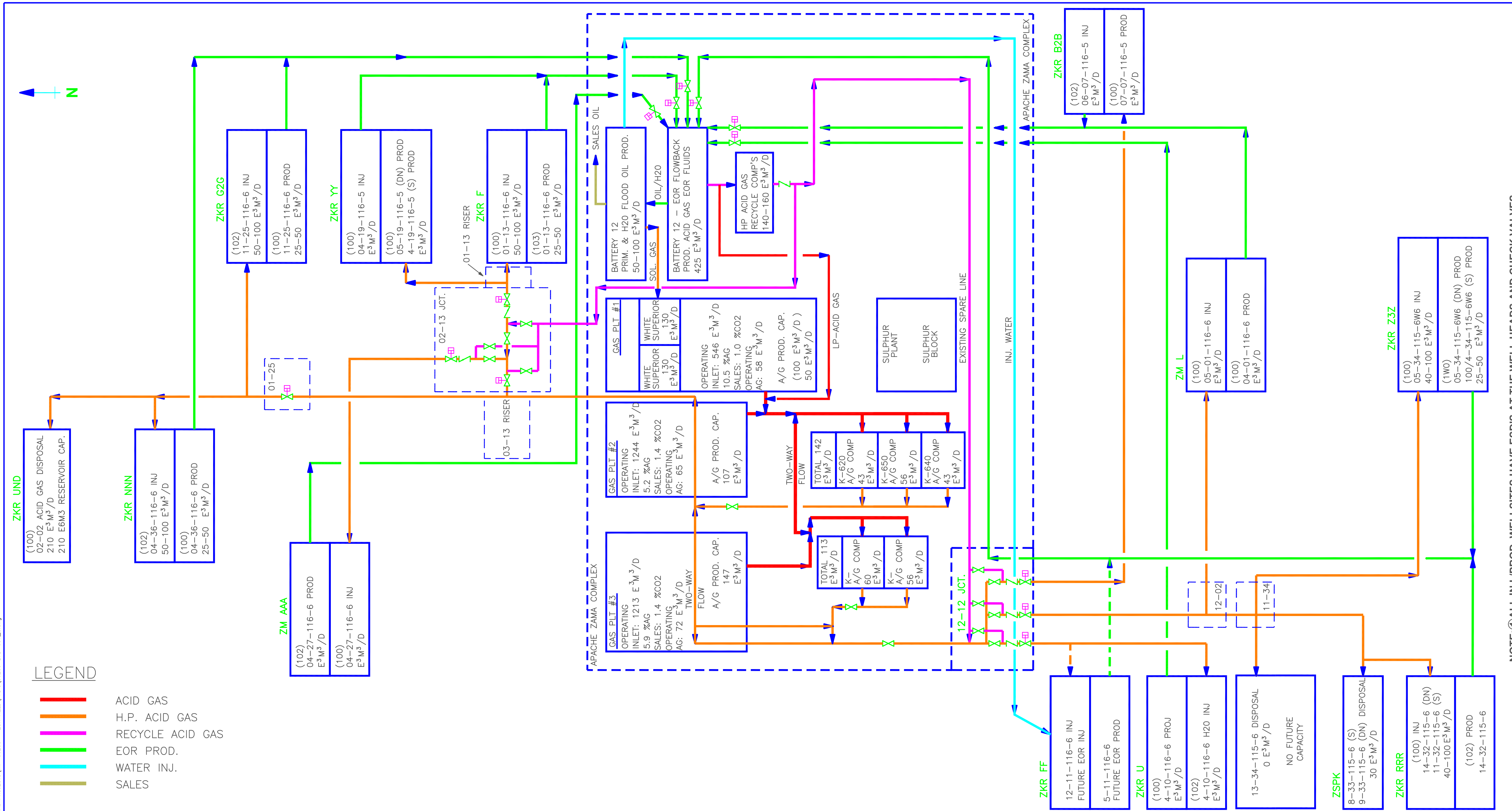
MILLENIA
Resource Consulting

APACHE CANADA LTD.

Zama EOR System Map
Phases I, II, & III

P:\APACHE\ZAMA\06200 EOR Field P&IDs\Map\Zama EOR System Map - Rev 7.pdf
2006-MM-DD

Figure 5



NOTES	REFERENCE DRAWINGS	REV.	DATE	BY	DESCRIPTION	CHK'D	APP'D	CLIENT
		A	05.01.15	AAS	ISSUED FOR REVIEW (MRC JOB# 04120)			
		B	05.02.06	AAS	REMOVED WHITE COMP – RECYCLE COMP. (04124)			
		C	05.04.19	TR	GENERAL REVISION (MRC JOB# 04124)			
		D	?5.04.22	CA	GENERAL REVISION (MRC JOB #04124)			
		E	05.06.24	HY	UPDATE PINNACLE NAME (MRC JOB #04124)			
		F	06.02.14	KM	GENERAL REVISION (MRC JOB# 04124)			
		G	06.05.25	EE	GENERAL REVISIONS (MRC JOB# 06200)			

ENGINEERING & PERMIT STAMPS

	BY	DATE
DRAWN:	NK	05.01.03
CHECKED:		
DESIGN:		
APPROVED:		
CLIENT:		
CADNAME:	06200–BFD–001	

Apache CANADA LTD.

MILLENIA Resource Consulting

APACHE ZAMA

OVERVIEW ZAMA ACID GAS EOR PROJECT
COMPRESSION, INJECTION & PRODUCTION
BLOCK FLOW DIAGRAM

SCALE/PLOT SCALE: NTS | DRAWING NAME: D-06200-BFD-001 | REV. G

R:\APACHE_ZAMA\14-12-116-06 W6M BATTERY 12\EOR ACID GAS PROJECTS\WIP-06200 – EOR FIELD\PFD's\06200-BFD-001_G.dwg

Figure 6

Zama Keg River F Pool
Acid Gas EOR Approval No. 10328A Amendment

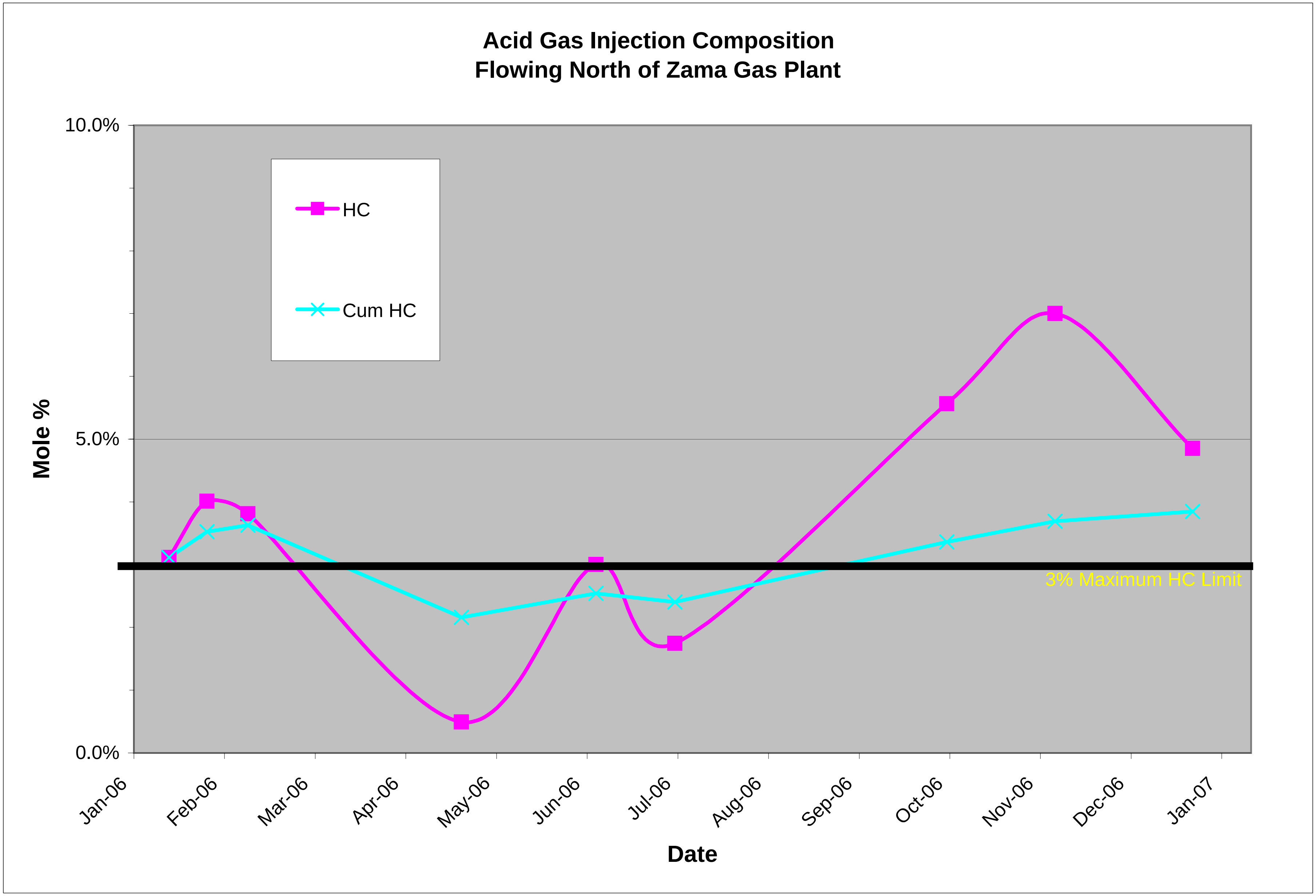


Figure 7

Zama Keg River F Pool
Acid Gas EOR Approval No. 10328A Amendment

Acid Gas Injection Composition
Flowing South of Zama Gas Plant

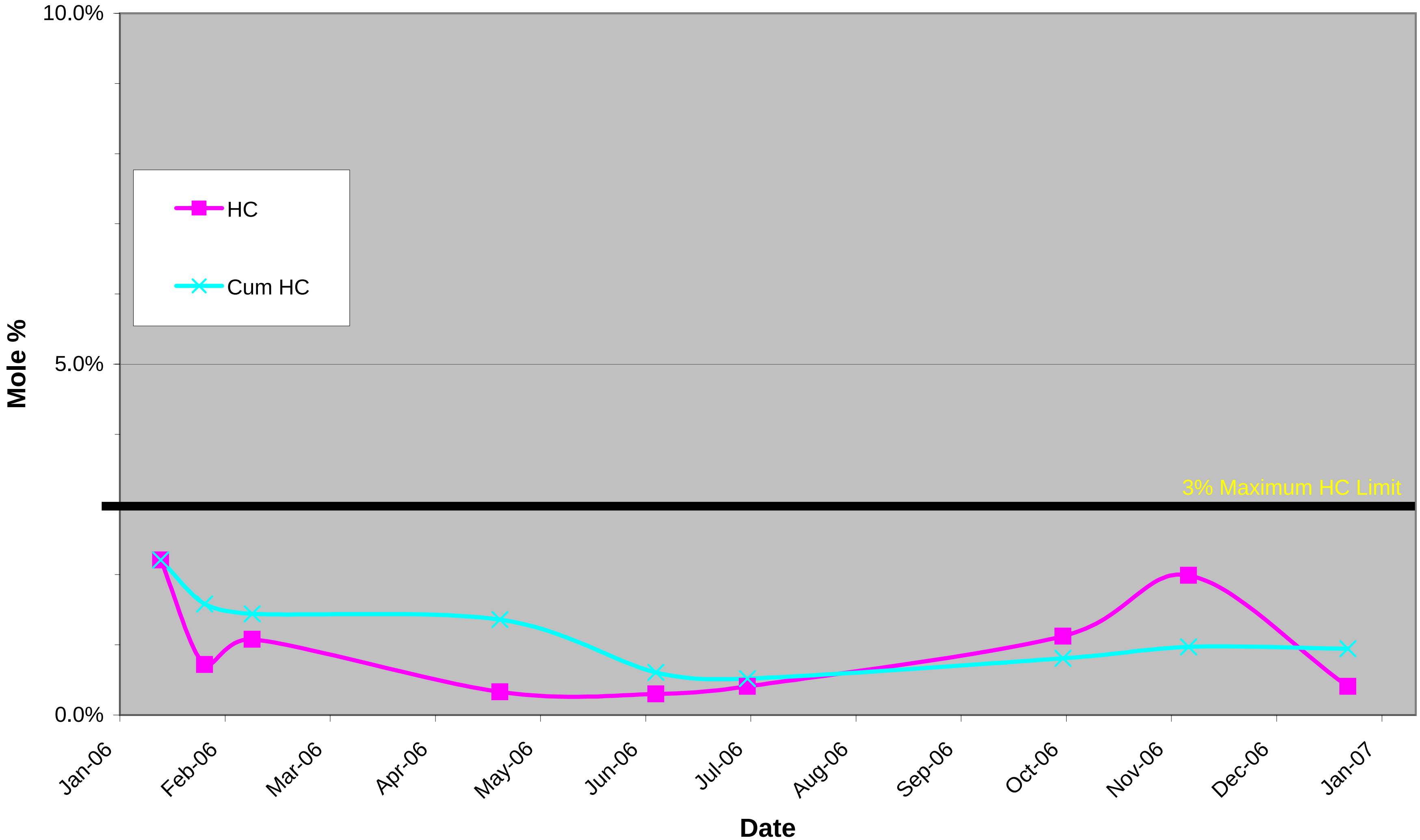


Figure 8

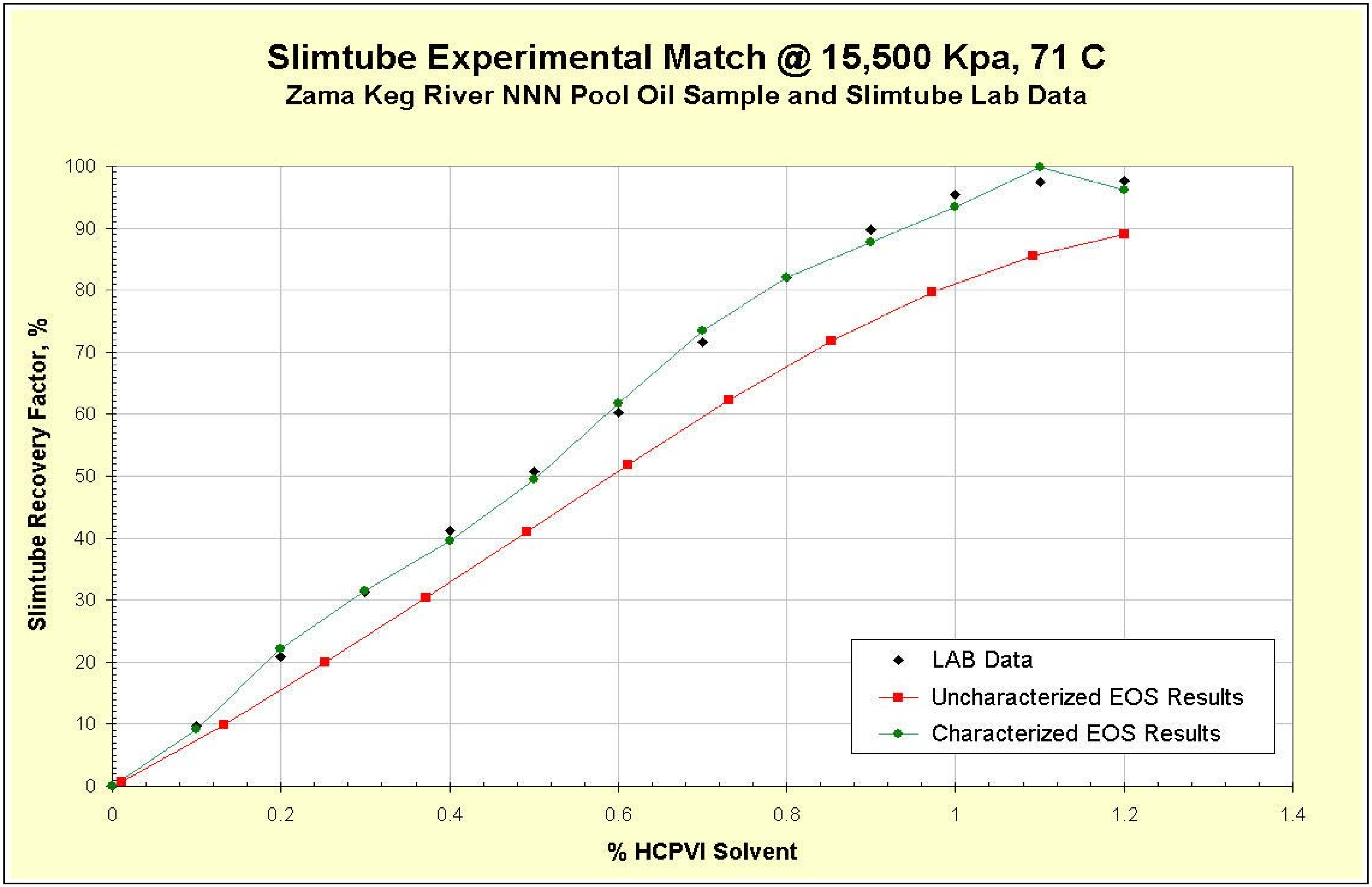

Slimtube Experimental Match @ 15,500 Kpa, 71 C
Zama Keg River NNN Pool Oil Sample and Slimtube Lab Data
Slimtube Recovery Factor, %
100
90
80
70
60
50
40
30
20
10
0
0
0.2
0.4
0.6
0.8
1
1.2
1.4
% HCPVI Solvent
LAB Data
Uncharacterized EOS Results
Characterized EOS Results

Figure 9

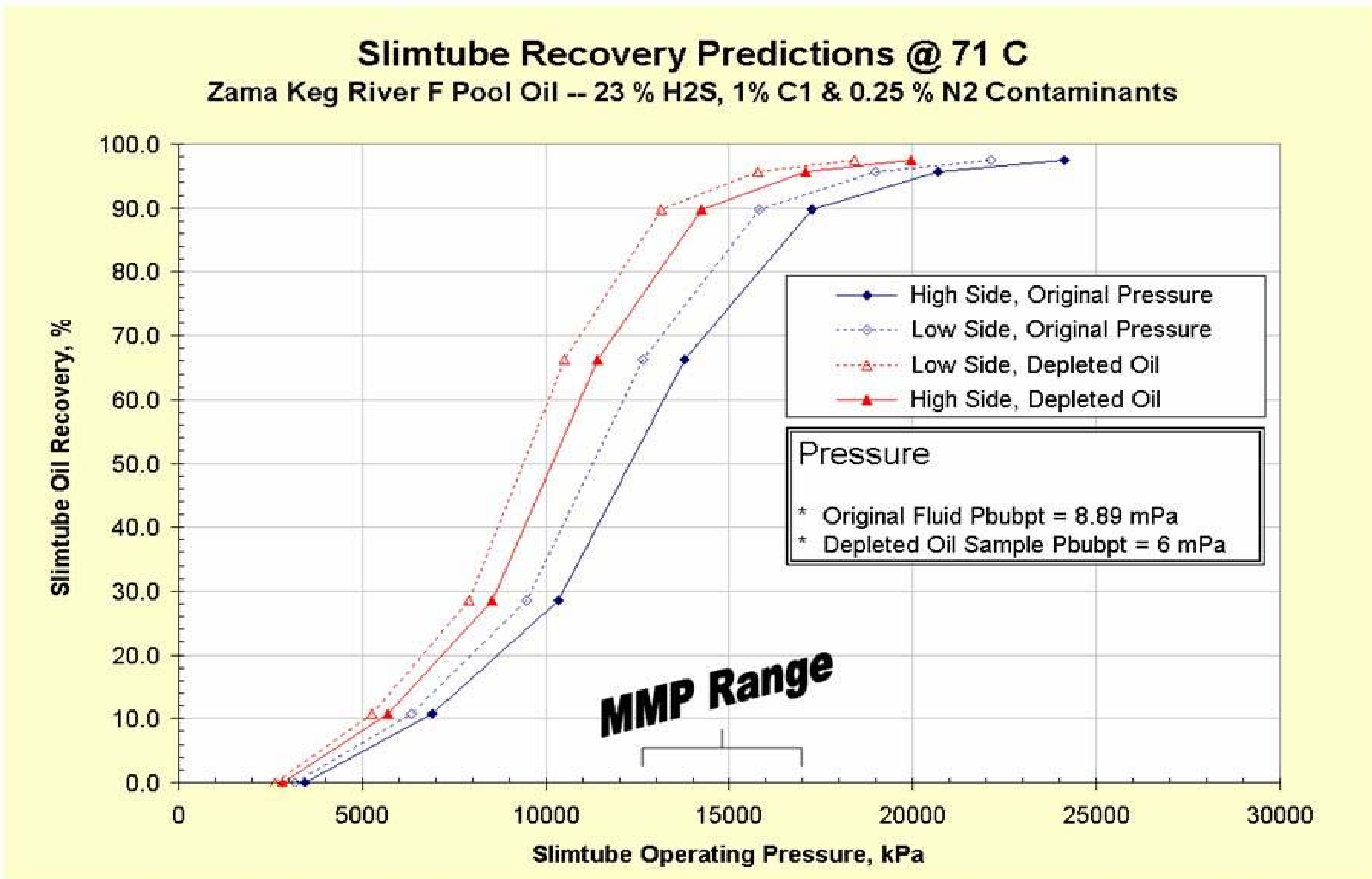

Slimtube Recovery Predictions @ 71 C
Zama Keg River F Pool Oil -- 23 % H2S, 1% C1 & 0.25 % N2 Contaminants
Slimtube Oil Recovery, %
100.0
90.0
80.0
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.0
0
5000
10000
15000
20000
25000
30000
Slimtube Operating Pressure, kPa
High Side, Original Pressure
Low Side, Original Pressure
Low Side, Depleted Oil
High Side, Depleted Oil
Pressure
* Original Fluid Pbubpt = 8.89 mPa
* Depleted Oil Sample Pbubpt = 6 mPa
MMP Range

Figure 10

Zama Keg River F Pool
Acid Gas EOR Approval No. 10328A Amendment

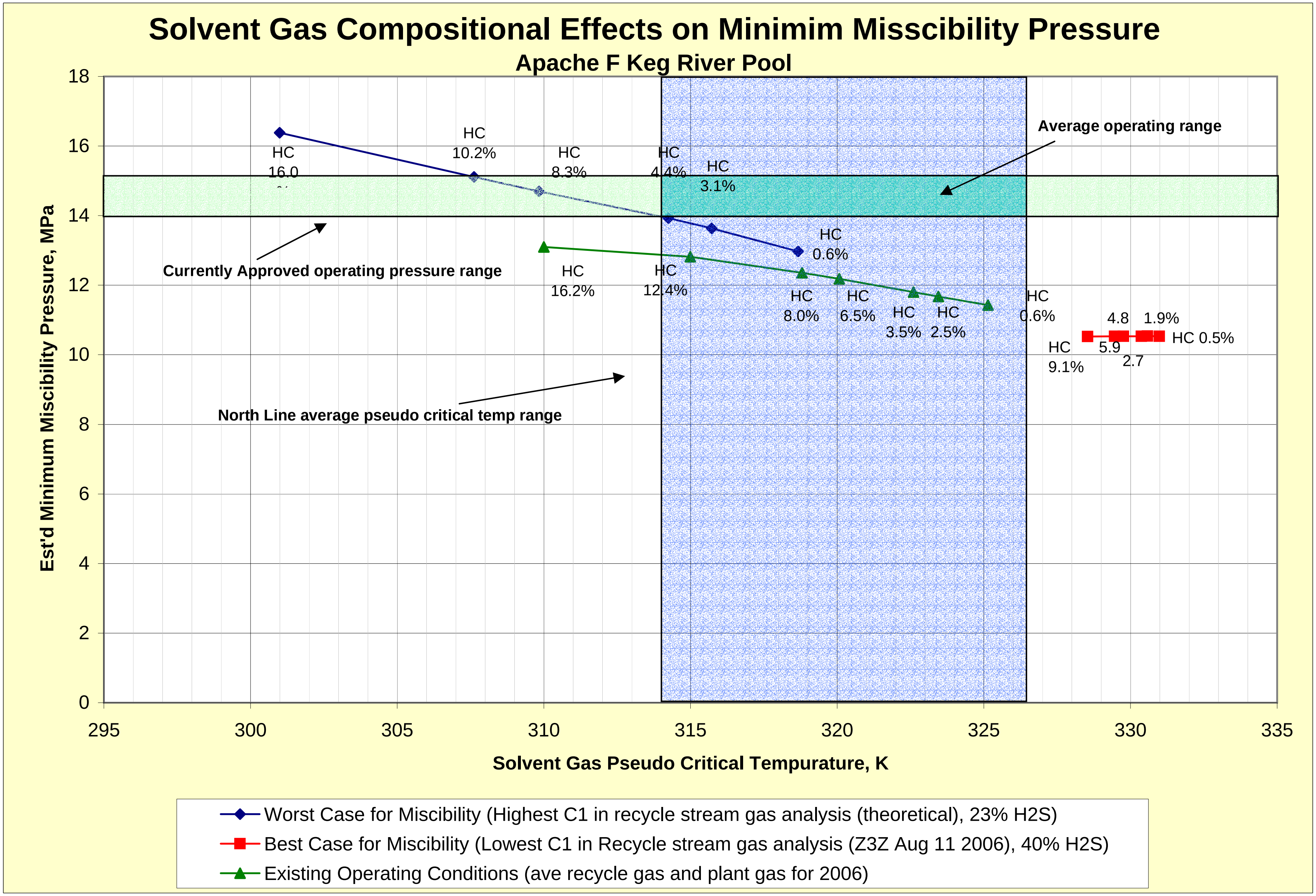


Figure 11

Zama Keg River F Pool
Acid Gas EOR Approval No. 10328A Amendment

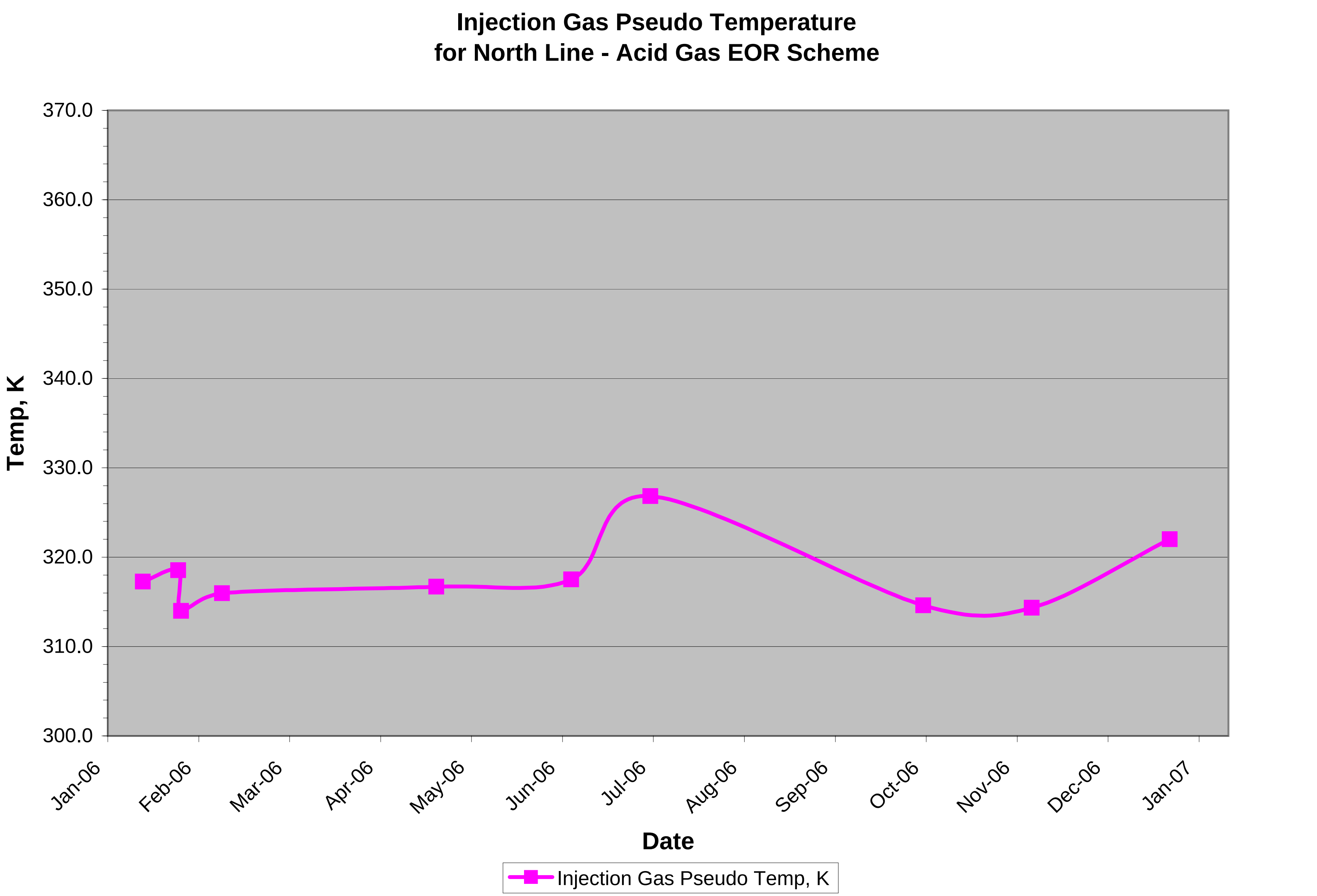


Figure 12

Zama Keg River F Pool
Acid Gas EOR Approval No. 10328A Amendment

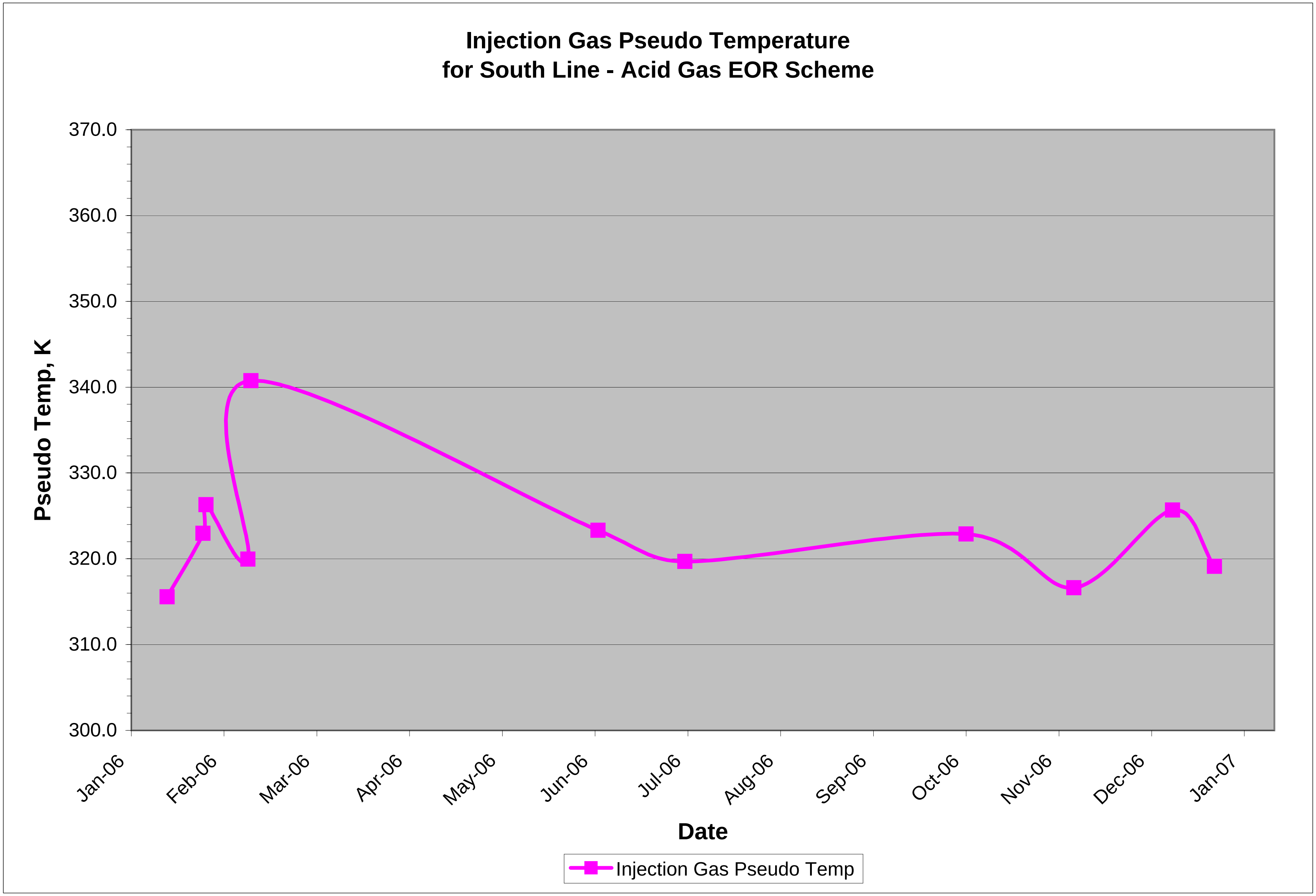


Figure 13

Zama Keg River F Pool
Acid Gas EOR Approval No. 10328A Amendment

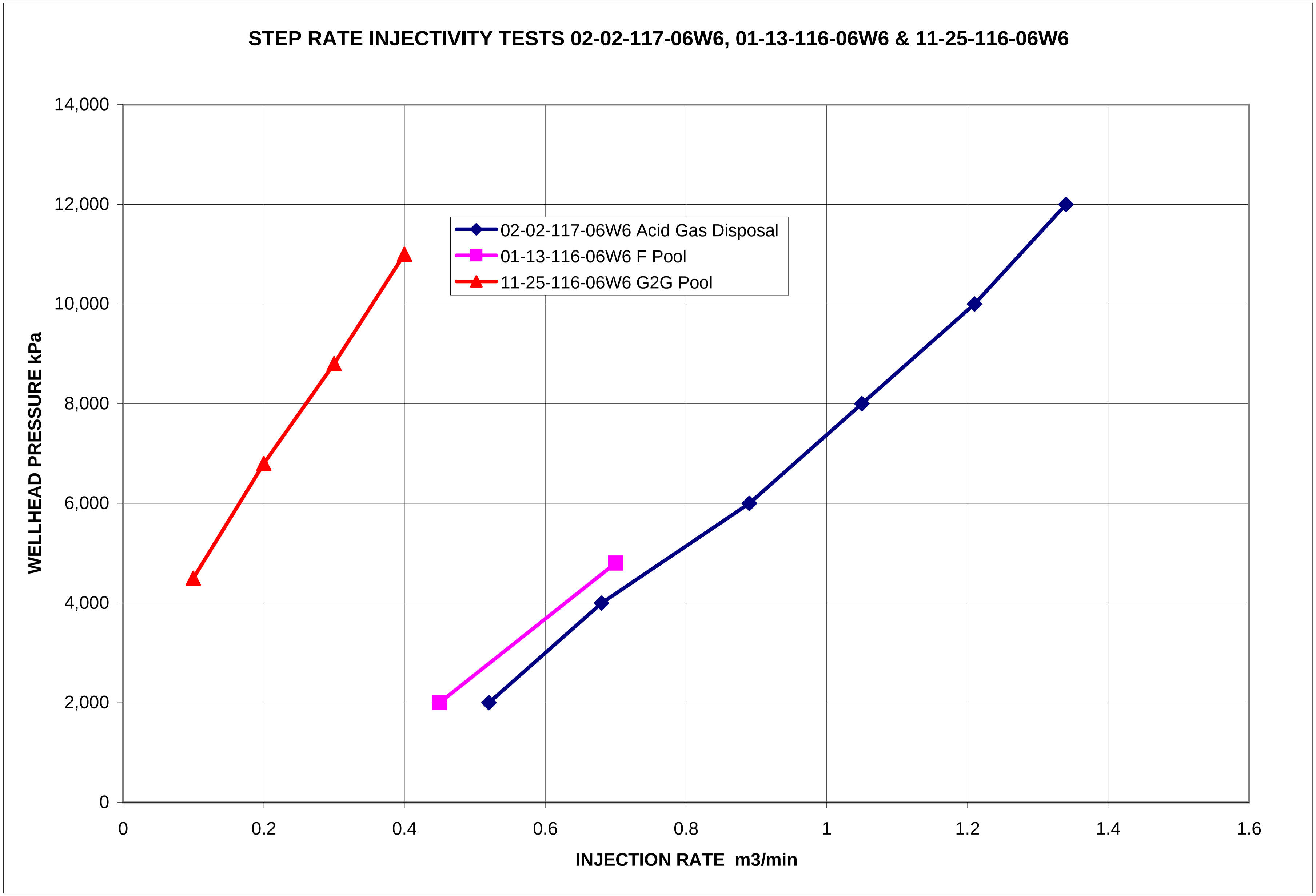


Figure 14

APPENDIX B

TABLE OF MVA TECHNIQUES AND APPLICATIONS

Data	Application	Used at Zama for MVA
Well-Specific Data	Baseline geology – hydrogeology – reservoir characterization – seal characterization - static modeling – dynamic modeling	Yes
Downhole (geophysical) Logs	Rock properties – reservoir characterization – seal characterization – static and dynamic modeling	Yes
Spontaneous Potential	Rock properties – geochemistry – water resistivity	Yes
Resistivity and Microresistivity	Rock properties – reservoir characterization – geochemistry – water and oil saturation	Yes
Resistivity Imaging	Rock properties – lithology characterization – geomechanical properties – fracture and fault detection – reservoir anisotropy	Yes
Sonic Imaging	Rock properties – lithology characterization – geomechanical properties – fracture characterization – stress analysis and stability	No
Sonic – Open Hole	Rock properties – sonic porosity – geomechanical properties – 3D rock mechanics – permeability estimates – pore pressure	Yes
Sonic – Cased Hole	Wellbore integrity – cement bond identification – cement bond quality – hydraulic isolation determination	No
Ultrasonic – Cased Hole	Wellbore integrity – cement bond identification – cement bond quality – hydraulic isolation determination – well damage and corrosion	No
Spectral Gamma Ray	Rock properties – lithology characterization – facies definition	Yes
Nuclear Porosity	Rock properties – neutron porosity – density porosity – bulk density – lithologic characterization – geomechanical properties – gas ID	Yes
Nuclear Spectroscopy	Rock properties – lithologic characterization – geochemical stratitgraphy	No
Magnetic Resonance	Rock properties – lithologic characterization – permeability – effective porosity – irreducible water saturation – hydrocarbon ID	No
Caliper – Open Hole	Rock properties – borehole rugosity	Yes
Caliper – Cased Hole	Wellbore integrity – casing damage	No
Flow Characterization	Geochemical characterization – reservoir characterization – volumetric flow rates – injectivity – wellbore integrity	No

Continued . . .

Data	Application	Used at Zama for MVA
Drill Stem Tests	Reservoir characterization – permeability – formation pressure – injectivity – formation damage due to drilling	Yes
Pressure Transient Analyses	Reservoir characterization – permeability – formation pressure – injectivity – formation damage due to drilling	Yes
Mini-Frac Tests	Reservoir characterization – seal characterization – geomechanical properties – rock competency	Yes
Pressure/Temperature	Geochemical characterization – reservoir characterization – wellbore integrity	Yes
Tiltmeters	Geomechanical characterization – reservoir characterization	No
Seismic Imaging (vertical seismic profiles)	Reservoir characterization – permeability – injectivity – geomechanical properties – geochemistry	No
Drilling Records	Wellbore integrity – reservoir characterization	Yes
Well Completion Records	Wellbore integrity – reservoir characterization – simulation modeling	Yes
Well Stimulation Records	Wellbore integrity – reservoir characterization – simulation modeling – geomechanical properties	Yes
Well Workover Records	Wellbore integrity – reservoir characterization	Yes
Production Records (oil, gas, water)	Reservoir characterization – injectivity – simulation modeling	Yes
Injection Records (gas, water)	Reservoir characterization – injectivity – simulation modeling	Yes
Cuttings Collection and Analysis	Lithology characterization – reservoir characterization – seal characterization – geochemistry	Yes
Core Collection and Analysis	Lithology characterization – reservoir characterization – seal characterization – permeability – geomechanical properties – geochemistry	Yes
Rock-Specific Data (from core/cuttings)	Baseline geology – reservoir characterization – seal characterization – geochemistry – static modeling – dynamic modeling	Yes

Continued . . .

Data	Application	Used at Zama for MVA
Mineralogy and Lithology Analyses	Reservoir characterization – seal characterization – geochemical properties – geomechanical properties – static and dynamic modeling	Yes
X-Ray Diffraction (XRD)	Mineralogy – chemical composition – geochemical modeling	Yes
X-Ray Flourescence (XRF)	Mineralogy – chemical composition – geochemical modeling	Yes
Scanning Electron Microprobe (SEM)	Mineralogy – chemical composition – microstructure – geomechanical properties – geochemical modeling	Yes
CT Scan	Porosity – permeability – microstructure – geomechanical properties	No
Geomechanical Analyses	Geomechanical properties – permeability – failure threshold pressure – elastic and strength properties – geomechanical modeling	Yes
Static and Dynamic Elastic Testing	Geomechanical properties – elastic and strength properties – geomechanical modeling	Yes
Young's Modulus	Geomechanical properties – stiffness	Yes
Poisson's Ratio	Geomechanical properties – strain characterization – geomechanical modeling	Yes
Permeability Analyses	Permeability – injectivity – dynamic modeling	Yes
Standard Core Plug Permeability	Permeability – single-phase (oil, gas, or water) permeability – injectivity	Yes
Relative Permeability Tests	Permeability – multiphase (oil–gas–water) permeability – injectivity	No
Pore Entry Mercury Injection Test	Permeability – pore distribution – pore geometry – capillary pore pressure	Yes
Probe Permeameter Test	Permeability – air permeability – injectivity	No
Reservoir Fluid Data	Baseline geology – hydrogeology – geochemistry – static and dynamic modeling	Yes
Gas-to-Oil Ratio	Geochemistry – dynamic modeling	Yes
Water Chemical Composition	Geochemistry – dynamic modeling	Yes
Water Specific Gravity	Geochemistry – dynamic modeling	Yes
Salinity	Geochemistry – dynamic modeling	Yes
Resistivity	Geochemistry – dynamic modeling	Yes
Gas Composition	Geochemistry – dynamic modeling	Yes

Continued . . .

Data	Application	Used at Zama for MVA
Oil Gravity	Geochemistry – dynamic modeling	Yes
Viscosity	Geochemistry – dynamic modeling	Yes
Salt Content	Geochemistry – dynamic modeling	Yes
Reservoir Data	Baseline geology – hydrogeology – geochemistry – geomechanical properties – static and dynamic modeling	Yes
Lithology	Geology – static and dynamic modeling	Yes
Average Depth to Top of Pay	Geology – static and dynamic modeling	Yes
Datum (ft or m) (mean sea level)	Geology – static and dynamic modeling	Yes
Minimum Depth	Geology – static and dynamic modeling	Yes
Maximum Depth	Geology – static and dynamic modeling	Yes
Average Pay Thickness	Geology – static and dynamic modeling	Yes
Average Porosity	Geology – static and dynamic modeling	Yes
Secondary Porosity	Geology – static and dynamic modeling	Yes
Average Permeabilty	Geology – static and dynamic modeling	Yes
Maximum Permeability	Geology – static and dynamic modeling	Yes
Minimum Permeabilty	Geology – static and dynamic modeling	Yes
Average Initial Water Saturation, %	Geology – static and dynamic modeling – geochemistry	Yes
Average Reservoir Temperature	Geology – static and dynamic modeling – geochemistry – geomechanical properties	Yes
Initial Reservoir Pressure	Geology – static and dynamic modeling – geochemistry – geomechanical properties	Yes
Current Reservoir Pressure	Geology – static and dynamic modeling – geochemistry – geomechanical properties	Yes
Bubble Point	Geology – static and dynamic modeling – geochemistry	Yes
Residual Oil/Gas, %	Geology – static and dynamic modeling – geochemistry	Yes
Formation Volume Factor at Reservoir Pressure	Geology – static and dynamic modeling	Yes

Continued . . .

Data	Application	Used at Zama for MVA
Oil Formation Volume Factor at Bubble Point	Geology – static and dynamic modeling	Yes
Original Oil in Place	Geology – static and dynamic modeling	Yes
Thickness of Closure	Geology – static and dynamic modeling	Yes
Primary Drive Mechanism	Geology – static and dynamic modeling	Yes
Initial Gas-to-Oil Ratio	Geology – static and dynamic modeling – geochemistry	Yes
Current Gas-to-Oil Ratio	Geology – static and dynamic modeling – geochemistry	Yes
Geophysical Survey Data	Geology – structural architecture – geomechanical characterization – reservoir characterization	No
2D Seismic Surveys	Geology – structural architecture – geomechanical characterization – reservoir characterization	No
3D Seismic Surveys	Geology – structural architecture – geomechanical characterization – reservoir characterization	No
Crosswell Seismic Profiling	Geology – structural architecture – geomechanical characterization – reservoir characterization	No
Crosswell Microseismic Profiling	Geology – structural architecture – geomechanical characterization – reservoir characterization	No
Gravimetric Surveys	Geology – structural architecture – geomechanical characterization – reservoir characterization	No
Interferometric Synthetic Aperture Radar (InSAR)	Geology – structural architecture – geomechanical characterization – reservoir characterization	No
Magnetic Anomoly Surveys	Geology – structural architecture – geomechanical characterization – reservoir characterization	No
Microseismic Array Surveys	Geology – structural architecture – geomechanical characterization – reservoir characterization	No
Tiltmeter Array Surveys	Geology – structural architecture – geomechanical characterization – reservoir characterization	No