A review of the Issaran Heavy Oil Field, Egypt

Introduction:

This report is prepared as a means of giving background information for the Issaran Heavy Oil Field located along the west side of the Gulf of Suez approximately 200 kilometres southeast of Cairo. The oil is trapped within Miocene Carbonate strata at a depth ranging from 500-700 metres. The main producing horizons are the Lower Miocene Gharandal Group, principally the Nukhul Formation, which contains the principal cold flow oil production. The Middle Miocene Ras Malab Group contained bitumen in the Lower and Upper Dolomites of the Belayim/South Gharib Formations. These deposits of bitumen generally required thermal recovery methods to produce the wells.

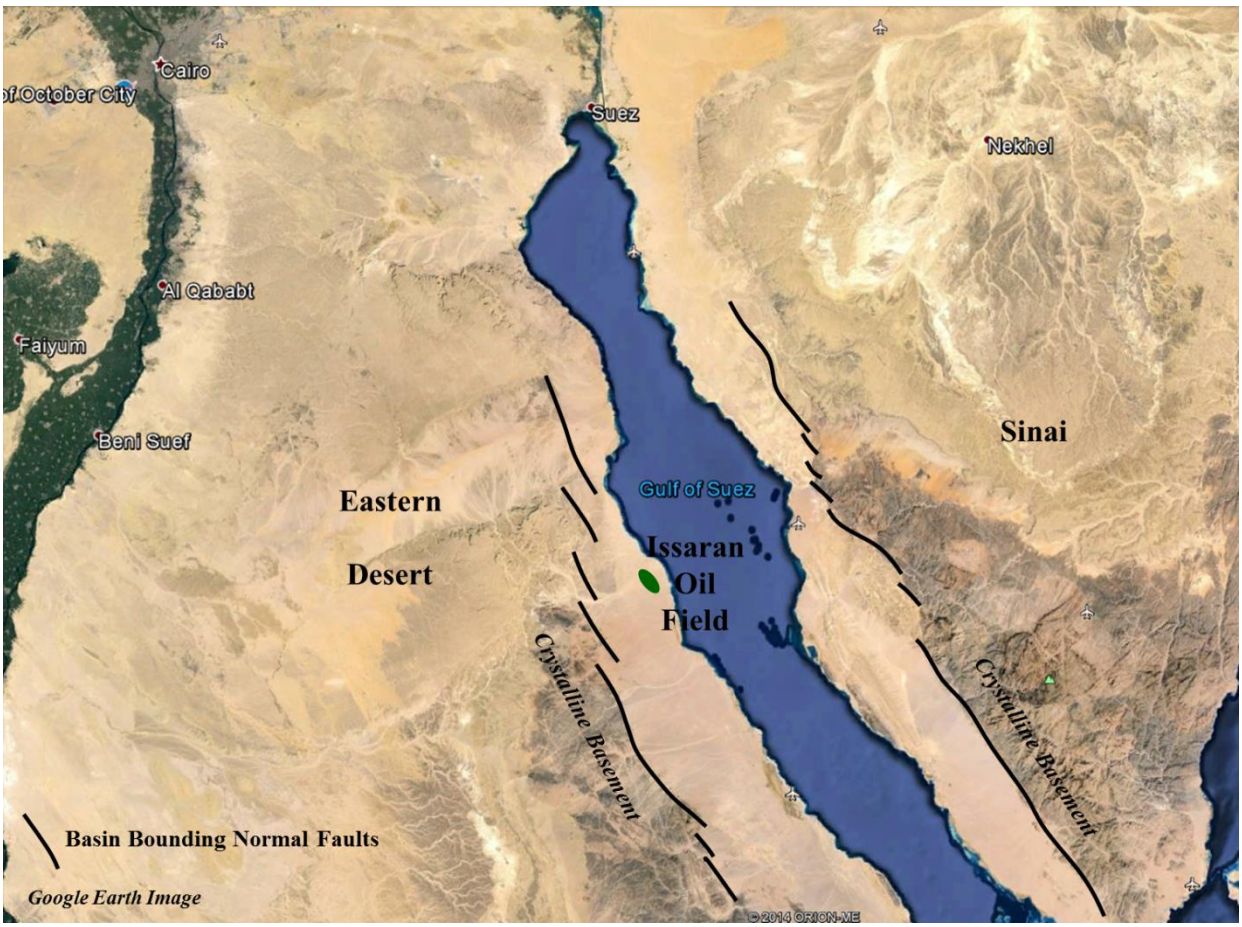

Figure 1: Location of the Issaran Oil Field

The Issaran Heavy Oil Field is located along the west flank of the Gulf of Suez extensional system (Figure 1). Crystalline Basement rock are exposed in the Eastern Desert and a series of down to the east normal faults associated with the Gulf of Suez Rift system create

accommodation space for the deposit of up to 5000 metres of sedimentary rock into the extensional basin. Associated with these basin bounding normal faults are a series of antithetic faults, which are generally down to the west and create the fault trap to form the Issaran Oil Field (Figure 2).

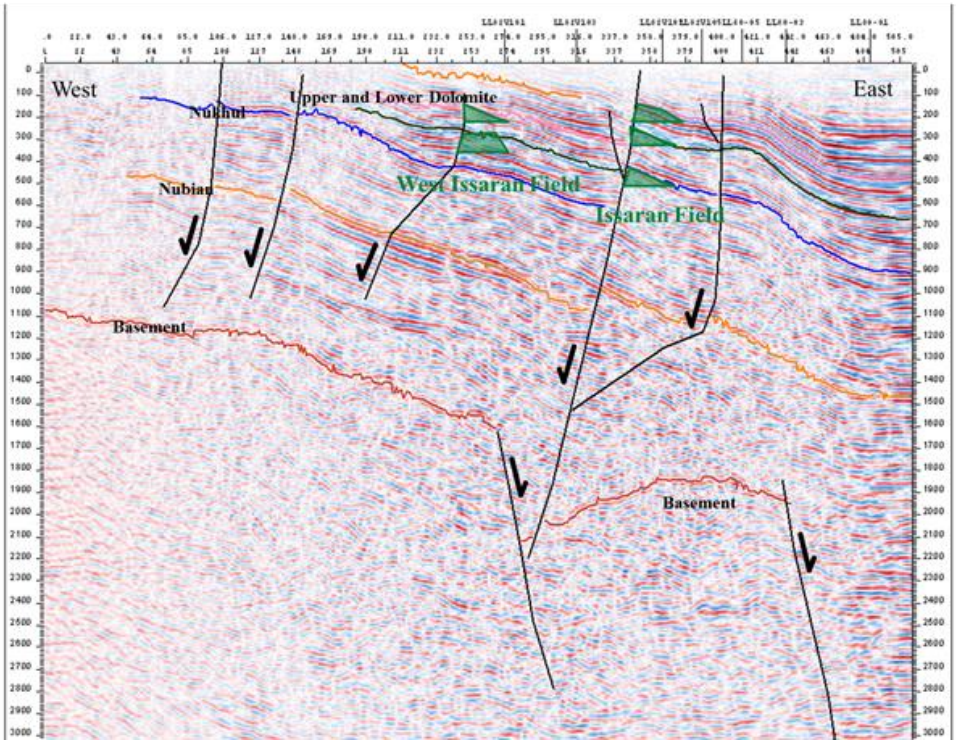

Figure 2: 2D seismic Line through the Issaran Field

The field produces cold production from the Nukhul Formation, the deepest producing stratigraphic horizon. A thermal recovery process has been implemented in the Upper and Lower Dolomites based on a Cyclic Steam Stimulation recovery scheme, where heat is injected into the formation and allowed to build up followed by production from the well. The cold production from the Nukhul Formation is 12^0 API oil. Typically the viscosity of this oil would classify it as a high viscous fluid; however due to the high geothermal gradients associated with the extensional setting the oil is at elevated formation temperatures creating reduced viscosity and cold flow. The bitumen trapped in the Upper and Lower Dolomites is heavier (8^0 API) and not as hot due to the shallower depth, hence it does not flow unless it is heated and the viscosity of the oil is reduced.

A Fractured Reservoir:

The carbonates are in a structurally deformed section. The deformation in the strata is predominantly faulting but associated with the faulting is an extensive fracture system. The evidence of fractures are:

- core intensely fractured to rubble
- Image logs with interpreted fracture zones
- wash-out on the calliper log
- pervasive loss of circulation while drilling
- large variations in initial production rates

- varying fluid recoveries
- variable water cuts

Core analysis of porosity and permeability show values of porosity exceeding 30% and permeabilities of up to 800 millidarcies. Average permeabilities from core are approximately 10 to 100 millidarcies. However, pressure transient analysis of wells show permeabilities of 3 Darcies based on curve matching (Figure 3). Core measurements are point values within the reservoir and are not diagnostic of the reservoir permeability. Pressure transient analysis is a more reliable tool to evaluate the reservoir permeability as it uses pressure decline and build-up to see the entire reservoir. The discrepancy between the two values is likely indicating the existence of fractures within the reservoir. Core analysis cannot measure fracture permeability and as such, core based permeability analysis will always under-estimate the permeability of the reservoir, especially a fractured reservoir.

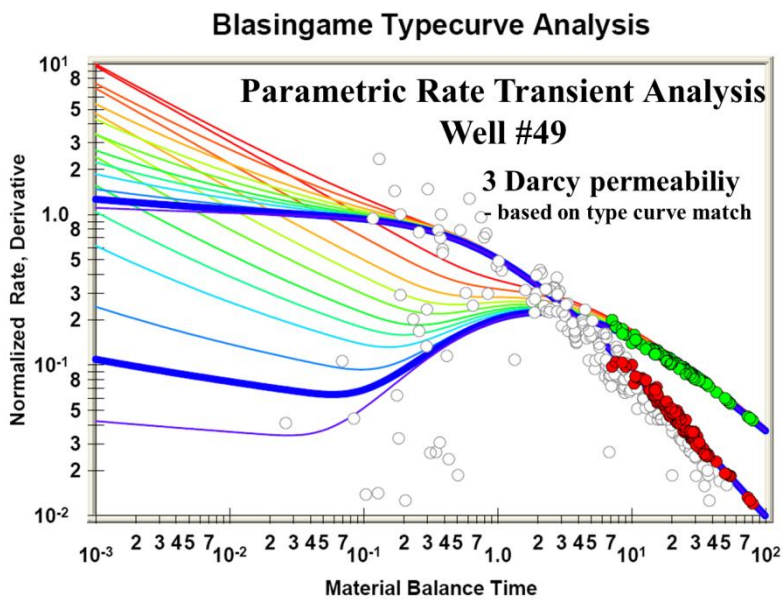

Figure 3: Pressure Transient Analysis of Well #49

Implications of a Fractured Reservoir:

The implications of a fractured reservoir are directed principally to fluid flow through the rock. The enhanced permeability brought about by fractures will mean that fluids will move farther with greater velocity through the rock mass. In a hydrocarbon saturated rock this is useful as the drainage radius of any given well is improved. Essentially this is what is simulated by hydraulic fracturing or well stimulation. Fluids are injected into the reservoir at great pressure to reduce the effective principal stresses and drive the system into failure. The failures (fractures) are injected with fluids carrying proppant. The frac fluid is then allowed to be produced back to the well bore and the fractures are left in the rock held open by the proppant. In this way well productivity is greatly improved.

In some cases fracture permeability is a problem. In reservoirs with high water lines fracture may connect the well to the water leg and as a result the well will cone water leading to reduced oil production. In the case of the cyclic steam injection programs the fractures initially appear to

be good as the early cycles will inject steam along the fracture surface exposing much of the reservoir to early heat. Unfortunately subsequent cycles will continue to use the same fracture pathways and the effectiveness of the later cyclic stages are compromised. Eventually steam will break through to other wells very early in the process making the steam flood ineffective with potential negative economic consequences.

The Devonian aged Grossmont Formation in northern Alberta is a fractured carbonate with thick bitumen pay zones. Of the 1.8 trillion barrels of bitumen trapped in the Athabasca-Fort McMurray area of northeastern Alberta approximately 536 billion barrels are within carbonate rocks of which 300 billion are estimated in the Grossmont Formation. A pilot Cyclic Steam Stimulation was implemented by Unocal in Buffalo Creek between the years 1980-86. A central vertical injector was drilled surrounded by three observation wells approximately 30 metres from the injector. The pilot produced over 100,000 barrels of oil over 6 years and 10 cycles with a steam/oil ratio of 6.8. Two major problems developed with the pilot, poor quality control on the surface steam with numerous operational difficulties associated with the steam generation and the loss circulation problems with the drilling of the well. The loss of circulation is a common problem in the Issaran Field and is caused by drilling fluids being lost within the natural fracture system.

By 2008 over $750 million dollars had been invested in trying to get commercial oil of the Grossmont Formation. Laracina Energy Ltd. is one of the few operators that are successfully producing bitumen from the Carbonate strata. The company recognized they were dealing with a fractured reservoir and switched from a CCS approach to a SAGD process (Steam Assist Gravity Drive) with the assist of chemical solvents. Early reports on their process are that they are producing 1800 bopd from 2 SAGD wells pairs. The evaluation is still early but their approach seems to hold more promise than the CCS process.

The SAGD process requires two horizontal wells to be drilled parallel such that one well is immediately above a second well. Heat is injected into the upper well and the bitumen is melted and flows by gravity into the lower well. The system works efficiently in the oilsands but is still experimental in the bitumen saturated fractured carbonates. Laracina has indicated that their project works but it is unclear if the economics are favourable. The advantage of the SAGD process is that the fracture permeability is not as significant a factor as in the cyclic steam stimulation due to the lower fluid pressures and the influence of gravity.

Fractured Reservoir and Cold Production in the Issaran Field:

The Issaran Field is not fully developed for cold production. The fracture distribution is related to the fault formation. Although fractures are great enhancers of permeability within the reservoir, faults are generally permeability barriers. A fault is a zone of weakness within the rock mass. Faults do not form under one failure but are a series of failures that continue to occupy the same failure plane. This is called strain softening where the failure becomes the

weak point and subsequent failures continue to use the weakest surface. As the fault develops it grinds the adjoining rock into a fine flour to form a gouge on the fault surface. This gouge is made up of the country rock but its grain size is significantly reduced and as a result the permeability across the gouge is also reduced to the point where the fault seals.

Well #49 in the North Issaran Pool is an interesting well that shows this fault fracture relationship (Figure 4). The well went through a normal fault penetrating a section of fractures in the Upper and Lower Dolomite in the hanging wall and a regular thickness of Nukhul Formation in the footwall. The hanging wall strata contained original reservoir pressures while the Nukhul Formation in the footwall had depleted pressures due to offset production from other wells, indicating a fault seal. The Upper Dolomite section was tested at 410 bopd without any stimulation or thermal assist.

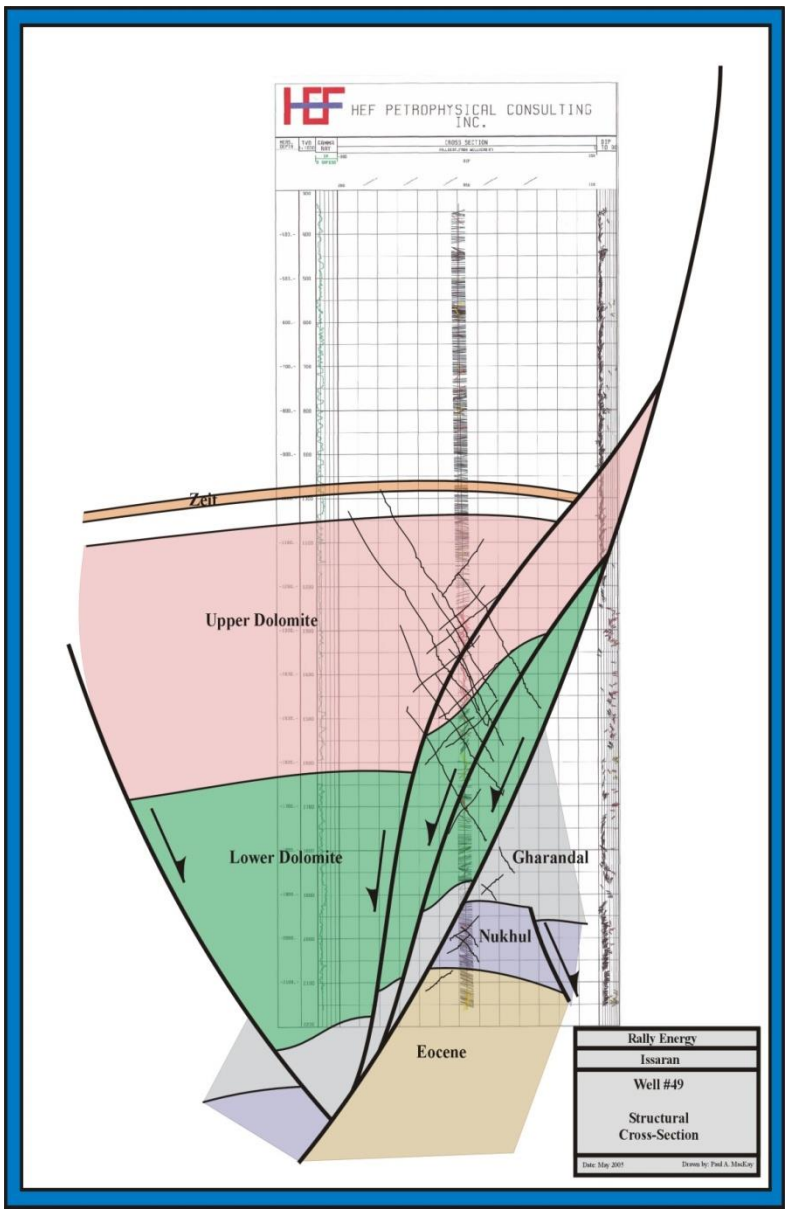

Figure 4: Cross-section through Well #49

The question is how did this well deliver cold production from a unit (Upper Dolomite) that must be heated by tertiary thermal process to produce in other areas of the field? The solution lies in the close proximity to the fault. Two features occur near the fault; the first is that there are numerous fractures that greatly improve the permeability of the system. The second is that the faults are sites of regional fluid migration. In this role the deep hot fluids move along the fault surface bring heat from depth and reducing the viscosity of the bitumen. Darcy's Law indicates the flow improves with the reduction of viscosity as well as an increase in permeability.

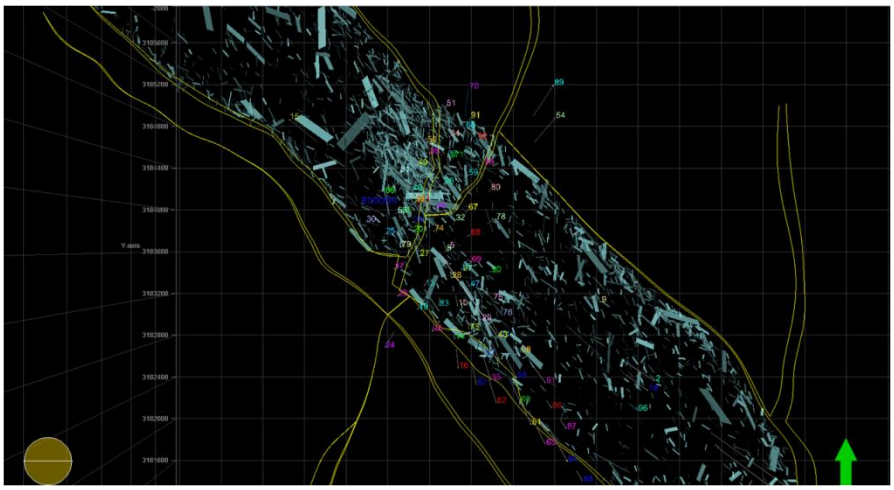

Figure 5: DFN model of the Issaran Field, filtered to fault proximity

A Discrete Fracture Network (DFN) model was created by Schlumberger of the field. This probabilistic model shows improved fracture networks in the down-thrown (hanging wall) block near the normal faults (Figure 5). Using the fracture distribution as a proxy for permeability the results show that intensely fractured Upper and Lower Dolomite exist for a great distance in the footwall of the fault. This extends a potential cold flow window for a great distance in the field. With this potential it is possible to increase the cold flow production of the field.

Other Exploration Potential:

The emplacement of the oil is interesting to consider. The Miocene section is charged from a deeper source. The charge likely came up the fracture conduits associated with the faults as part of the fault generation. Failure on faults is associated with high fluid pressures. High fluid pressures are generated at depth and are released by failure, the opening up of the fault and fluid migration. In many cases the elevated fluid pressures are the result of liquid hydrocarbon generation, a volume increasing process that increases fluid pressure. The high fluid pressures reduce the effective confining stresses and shift the mechanical stability of the system into failure. This results in failure in the rock, opening of the fault/fracture system and migration of hydrocarbons.

At depth below the Miocene carbonates is the Nubian sandstone, a thick porous sandstone that was penetrated by a well (well #8?) away from the faults and well down-dip. Exploration potential exists at depth and the existing 3D seismic data that covers the area is likely sufficient to evaluate the immediate explorations potential. The setting and petroleum system is indicative of deeper potential that is likely higher gravity oil.

Summary:

The existing cyclic steam stimulation is compromised by the natural fracture system within the reservoir. It may be possible to salvage value with a SAGD process but this will require further study and likely some form of test or pilot program. However it is likely that the cold production can be improved by exploiting the existing natural fracture systems near the faults. To exploit this potential will require drilling the down-thrown block, which tend to have better open

fracture networks and potentially better heat flow. This trap will work if the faults have sealing capacity, this tendency has been exhibited in Well #49. The deeper section has exploration potential and there is sufficient existing data to evaluate this potential.

Paul MacKay, Ph.D
P.Geol., P.Geoph.

November 2014