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SOME ASPECTS OF OIL SHALE - FINDING KEROGEN TO GENERATE OIL

Oil demand is predicted to continue to increase despite the high price of oil. The lagging supply increased the prices for oil and gas and a definitive oil replacement has still not been found. Huge oil shale resources discovered in the world, if developed, may increase petroleum supplies. Developing of oil shale needs the availability of low cost production; the greatest risks facing oil shale developing are higher production expenses and lower oil prices. There are several technologies for producing oil from kerogen bearing oil shale, by pyrolysis (heating, retorting). Oil shale is still technologically difficult and expensive to produce and the major impediment is cost. Developing oil shale accumulations means to face huge challenges, but an efficient oil shale development can be accomplished and an acceptable oil shale industry based on new technologies can be built nowadays.

Key words: *shale, continuous accumulation, oil shale, shale oil, total organic carbon, Rock-Eval, reserves estimation, Fischer assay, mining and retorting, in situ retorting and extraction, in capsule extraction.*

Introduction

Continuous accumulations are extensive petroleum reservoirs not necessarily related to conventional structural or stratigraphic traps [Klett and Charpentier, 2006]. These accumulations lack well defined down-dip petroleum water contacts and these are not localised by the buoyancy of oil or natural gas in water [Schmoker, 1996]. Unconventional continuous petroleum system consists of an accumulation of hydrocarbons found in low matrix permeability rocks accumulation depending of fracture permeability (either natural or as result of stimulation) for production, and contains large amounts of hydrocarbons, but with low recovery factor. Examples of continuous accumulations include tight gas reservoirs, coal bed gas, oil and gas in shale, oil and gas in chalk, basin-centred gas and shallow iatrogenic gas [Schmoker, 1996]. Unlike conventional production the oil produced from oil shale typically needs horizontal rather than vertical drilling.

Shale is a general petrological term covering a range of indurated, laminated pelitic rocks like shale, claystone, argillite, mudstone and marl. Distinguishing by their textural characters from other pelitic-argillaceus rocks the shale has always lamination or fissility. The oil shale is sometimes rich enough in kerogen to yield petroleum products following heating at temperatures of the order of 300-500 degree Celsius in absence of oxygen (pyrolysis).

The term oil shale is a misnomer because, first the mineralogy of this rock is not always argillaceous, sometimes it is carbonate-dominated marl, and second the organic component phase is not oil, but kerogen (the precursor to oil and gas) a mixture in various proportions of organic chemical compounds known as geopolymers [Bordenave, 1993] (Fig. 1).

Fig. 1. Oil shale stockpile at Enefit Energy`s White River Shale Mine, Utah, U.S.
From Beckwith R. and Writer S. (2012)

Sedimentary in origin of oil shale is result of the deposition of terrigene pelitic sediments together with organic matter in anaerobic condition in marine or continental environments (ponds, lakes or deltas) [Survey of Energy Resources, 2010]. Some oil shales were reported from high hydrogen low oxygen content environments like open marine anoxic, epicontinental seas (deeper part), rift associated anoxic lakes and seas, early spreading newly created oceans, deltas, lagoons and lakes. The burial (generally shallow burial) of this sediment was accompanied by diagenetic processes like compaction and conversion of original organic material into kerogen - geologic precursor to petroleum.

The kerogen corresponds to an insoluble organic matter of sapropelites, which yields oil on destructive distillation (pyrolysis). On heating sapropelitic kerogene yield oil and gas, on heating humic kerogen yield mainly gas [Bordenave, 1993].

The TOC (total organic carbon) is a measurement of the organic richness of a sediment and a basic geochemical parameter required to interpret any other geochemical information obtained by other investigation proceedings. The lean rocks – TOC an average lower than 0.1-1.0% are known as having no source rock potential. Good source rocks have high TOC values [Bordenave, 1993]. However, appraising source rocks indicate that not all high TOC source rocks have a good potential. Most shale interesting plays have an average of TOC greater than 3% in the range 3-5%.

Oil shale, ranging from Cambrian to Tertiary in age, is located in many parts of the world. Because of the higher costs only a few deposits of oil shale are currently (2010) developing - Estonia, China, Germany, Brazil and Israel [Survey of Energy Resources, 2010].

The oil shale classification was developed by A.C. Hutton [Hutton, 1987]; he divided the organic rich sedimentary rocks into three groups:

1) humic coals and carbonaceous shale,

2) bitumen impregnated rocks and

3) oil shale

Oil shale can be considered as thermal immature source-rocks, which have not yet generated oil and needs to be heated at 300-520°C to yield oil by pyrolysis. The term *shale oil* is used in this publication to refer to the liquid hydrocarbon products that can be directly extracted from the shale.

Oil shale resources

The oil shale «reserves» frequently listed in geological literature has to be considered in fact a contingent resources and not genuine reserves because they have not been «proven» yet as economically rentable. Total resources of a selected group of oil shale deposits in more than 30 countries were conservative estimated (not sufficiently explored for accurate estimation) [Dyni, 2006].

The basis for most of these estimations provides measurements of oil shale yield by Fischer Assay (process designed to approximate the recovery of surface retorting method). The Fischer method assay does not determine the total available energy in an oil shale; some oil shale may have a greater energy potential than that reported by the Fischer assay method, depending on the components of the «gas plus loss» [Dyni, 2006]. The same author considered the world oil shale in place resources to be more than 3 trillion barrels (estimation made in 2005).

According to US Geological data R. Beckwith and S. Writter presented a new assessment indicating that only in the Green River area (Colorado, Utah and Wyoming) the oil in place resources were estimated at 4.28 BOE (barrel oil equivalent) (Fig. 2) [Beckwith and Writer, 2012].

Beckwith (2012) unveiled the oil shale resources for several other countries too: China - 333 billion BOE, Russia - 248 billion BOE, Democratic Republic of Congo - 100 million BOE, Jordan - 90 billion BOE, Brazil - 82 billion BOE, Italy - 73 billion BOE, Morocco - 53 billion BOE, Australia - 32 billion BOE, Estonia - 16 BOE and Israel - 250 BOE.

America’s total oil shale could exceed 6 trillion barrels of oil equivalent. However, most of the shale is in deposits of insufficient thickness or richness to access and produce economically [U.S. Department for Energy, 2005].

Fig. 2. Oil sand containing oil generated from the Green River Formation, Asphalt Ridge Tar Sand Quarry, Utah, U.S. From Beckwith R. and Writer S. (2012)

Reserves estimation

Estimating conventional oil reserves is already a very arduous challenging; estimating oil reserves belonging to continuous accumulation of oil in shale is presently a very difficult calculation and an inexact evaluation method.

The organic matter contenting in oil shale is in reality exclusive kerogen, with no oil and only little extractable bitumen present. Nonetheless, oil shale must have a relative large (greater of 2% if cuttings and in the range 2-5% for core analysis) amount of TOC to be of commercial interest [Jarvie, 2004].

The grade of oil shale can be determined by measuring the yield of oil in shale sample in laboratory. This is perhaps the most common type of analysis currently used to evaluate an oil resource.

This method – «modified Fischer assay» standardized as ASTM method and described by Johnson et al. (2010), consists of heating a 100-200 gram sample crushed to - 8 mesh (2.38 mm mesh) screen in a small aluminium retort to 500°C at rate of 12°C per minutes and then held at that temperature for 40 minutes. The volatile vapours of oil, gas and water are passed through a condenser cooled with ice water (about 5°C) into a graduated centrifuge tube. The quantities reported in the original sample are the weight percentages of shale oil, water and shale residue (contains carbon char) and «gas plus loss» (non condensable gas yield) by difference.

Specific gravity of shale oil is measured and used to calculate the oil yield in gallon per ton

(GPT). The Fischer assay method does not determine total available energy in an oil shale it only approximates the energy potential of an oil shale-section [Dyni, 2006].

The same author reported (2006) that the commercial grade of oil shale as determined by their yield of shale oil, ranges from about 100 to 200 litre per metric tone (l/t) of rock. The US Geological Survey has used a lower limit of about 40 l/t for classification of federal oil shale lands. Other experts have suggested yielding over 40 litre of oil per tonne are considered economic.

For estimating US oil shale resources two measures are common used: resources in place and recoverable resources. The resources in place are distinguished according to their grade specifically, the gallons of oil that can be produced from a ton of shale. The rich shale that yield 25-50 and more gallon per ton are the most attractive for initial developing (Fig. 3).

Fig. 3. High-grade oil shale weathered into paper shale, Mahogany Zone, Utah, U.S.
The Mahogany Zone contains rich oil shale, averaging up to 80 gallon of oil per ton of rock.
From Beckwith R. and Writer S. (2012)

Deposits with grades below 10 gallons per ton are generally not considered as resources in place. Because oil shale production has been rewarding in the United States, slates calculation of recoverable resources has been on rough estimates of the fraction of the resource in place that can be accessed and recovered considering mining methods and processing losses [Taylor, 1987].

Some oil shale may have a greater energy than reported by the Ficher assay method depending on the components of the «gas plus loss» (non condensable gas yield). Other retorting methods such as the Tosco II process can yield in excess of 100% of the yield reported by Fischer assay and the Hytort process can yield up to three to four time the yield obtained by Fischer assay [Dyni, 2006]. The same author indicate that the Fischer assay method and close variations like the Seventh Approximation is the major source of information concerning oil shale reserves for the most deposits.

The Seventh Approximation specifics are:

1. use of the total petroleum system (of which assessment units are a subdivision) instead of plays,

2. estimation of potential additions to reserves instead of technically recoverable resources and

3. use of a 30-year forecast span (access risk) of an unlimited assessment time frame (30n years appears to be approaching the limit of a realist forecast span) [Schmoker and Klett, 2005].

Newer methods for estimating oil shale resources are the Rock-Eval and the «material-balance» Fischer assay technique. Both provide more information about the grade of oil shale, but are not very much used.

Downey M.W., Garvin J., Langomarsino R.C., Niklin D.F. (2011) proposed a quantitative evaluation of oil-in-place from measurements of the distillable oil in an oil shale, specifically from S1 peak measurements in a standard Rock-Eval analysis. The measurements obtained may then be up-scaled to calculate oil-in-place for a given formation, trend or basin. The authors compared these values to estimate ultimate recovery efficiency per well-bore based on decline curve analysis. In this way operators may glean greater insight into the recovery efficiency and as a result may determine the need for and lay plans to carry out the minimum amount of drilling and formation fracturing to ensure the maximum amount of oil extraction.

The Rock-Eval method was developed by the Institut Français de Pétrole in partnership with Petrofina in 1970. During heating of 100 gram of rock under Helium atmosphere at 300 °C for three minutes, then temperature is increased by 25°C/minute up 600°C several events were observed. Free hydrocarbons, oil or gas contained in the organic matter are vaporized at around 300°C; this thermo-vaporisation for a period of three minutes gives a peak called the S1 peak, expressed in HC/gram of rock, the S1 peak represents the free hydrocarbons in a rock; primarily indicates generated free oil. The greatest the S1 peak the greater amount of free oil [Bordenave, 1993].

Downey M.W., Garvin J., Langomarsino R.C., Niklin D.F. (2011) recommended the following application procedure for a quick look determination of oil in place:

1. Establishing S1 peak values, preferably from whole core, preferably every foot. This represents measured oil-in-place per unit volume of rock.

2. Upscale oil in place to acre-feet or section-feet (i.e. one square mile of surface area X one foot thick X hydrocarbon richness).

3. Resulting volume from core measurements is a minimum value for the oil-in-place volume.

Measurements of oil-in-place compared to production decline analysis will improve measurements of recovery efficiency.

The calculation steps as follows:

Step 1: grams of oil per section

$$\mathrm{M}_{\mathrm{S1HC}} = Ah(\rho_{Av})(S1_{Av})(.001) \div 8{,}11 \cdot 10^{-10}\text{, } \textit{acre-ft/cc}$$

Where: M_{S1HC} - mass of S1 hydrocarbons per section (g); A - area of interest in acres (sectional area – 640 acres); h - reservoir height (ft); ρ_{Av} - average bulk density (g/cc); $S1_{Av}$ - average S1 (mg/g).

Step 2: volume of oil per section (cc)

$$V_{S1HC} = M_{S1HC} \div \rho_{oil}$$

Where: V_{S1HC} - volume of S1 hydrocarbons per section (cc); M_{S1HC} - mass of S1 hydrocarbons per section (g); ρ_{oil} - density of oil (g/cc).

Step 3: barrels of oil per section

$$\textit{Oil in place per section (Bbl)} = \mathrm{V}_{\mathrm{S1HC}} \times 6.29 \cdot 10^{-6}\text{, } \textit{bbl/cc}$$

Oil in place from S1 (Simplified Equation)

$$\textit{Oil in place per 640 acre/ft}=4965.36 \times (\rho_{Av})(S1_{Av})(\rho_{oil})$$

Where: ρ_{Av} - average bulk density (g/cc); $S1_{Av}$ - average S1 (mg/g); ρ_{oil} - density of oil (g/cc).

$$\textit{Oil in place per 640 acre/ft}=9677.48 \times (S1_{Av})^{1}$$

Where: $S1_{Av}$ - average S1 (mg/g).

Conversions:

1 section = 640 acres

1 cc=$8.11 \cdot 10^{-10}$ acre-ft

1 cc=$6.29 \cdot 10^{-6}$ bbl

Specific gravity=141.5/(131.5+API gravity)

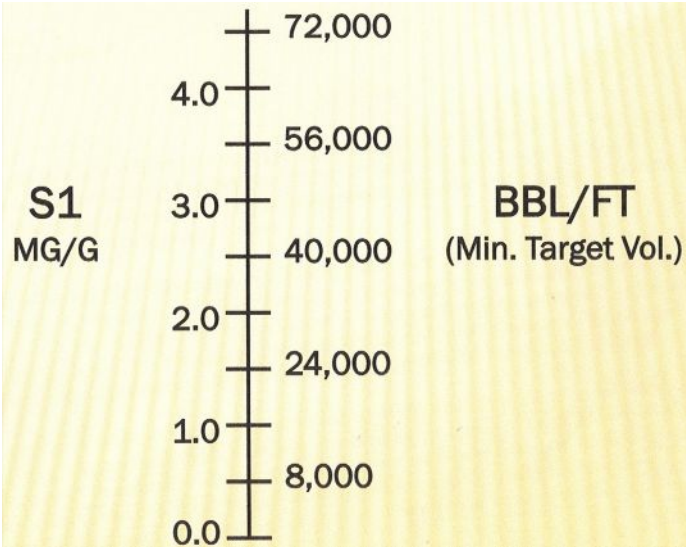
Specific gravity 1=1 g/cc

1 mg=.001 g

Quicklook conversion of S1 to oil[2]

1 *Assumes:*
2.5 g/cc Bulk Density
50° API Oil Gravity

Using S1 in mg/g to BBL of Oil in 640 acres/foot



Production methods

Nowadays industry research focused on development and testing of a variety of methods for extracting oil from oil shale like: extraction technique with higher resource recovery, reducing retorting energy input, protection of surface resourced and ground water (Fig. 4).

During the mid-1970s and early 1980s the petroleum industry produced oil on underground mining (under 200 meters depth) and surface retorting. Large volumes of water were required, only the kerogen richest sections were developed and large waste volumes of spent shale were created. AAPG-Energy Mineral Division reported in the Semi-Annual Report 2011 that current industry research focuses on development and testing of a variety of technique for extracting oil from oil shale and on minimizing the environmental impacts of these techniques. Most currently proposed extraction method promise 40 to 60% recovery of the total of resources; only surface mining methods would approach 100% [Miller, 2007].

The oil shale extraction methods (Table 1) - nowadays still highly uncertain economics - are as follows:

1. mining and retorting (destructive distillation)
2. in- situ retorting and extraction
3. in capsule extraction

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[2] *Assumes:*
2.5 g/cc Bulk Density
50° API Oil Gravity

Table 1. Advances in Oil Shale Technology (from Johnson H.R., Crawford P.M. and Bunger J.W., 2004)

Stage	Process Type	Advances	Status	Project
Mining	Open-Pit	Minor advances continue to reduce costs	Demonstrated at commercial scale	Stuart; Alberta
	Underground	Room and pillar approaches	Demonstrated commercial scale	Unocal; Others
Retorting	Conventional	Shale pre-heating increases gas and oil yields; extracts intermediate products before high temperature pyrolysis Combusting carbon residue on pyrolized shale generates process heat; reduces emissions and spent shale carbon content Recirculation of gases and capture of connate water from shale minimizes process water requirements. Lower heat rates reduce plasticization of kerogen-rich shales	Demonstrated at pilot scale in ATP	Stuart Shale
	In-Situ	Slower heating increases oil and hydrocarbon gas yield and quality Recovery of deeper resources enabled by heating technology Improved ability to control heat front by controlling heaters and back pressure	Proven at field scale Indicated Proven	Shell ICP Shell ICP Shell ICP
	Novel Processes	Supercritical extraction processes Higher heating rates Shorter "residence" durations "Scavengers" (hydrogen or hydrogen transfer/donor agents) Solvent extraction of kerogen from ore Thermal solution processes	Concept Research Proven Research Research Research	ATP
Processing	Value Enhancement	Separates nitrogen element for chemicals white generating fuels feedstocks	Proof of concept -1 yr from demo	Bunger, et al.

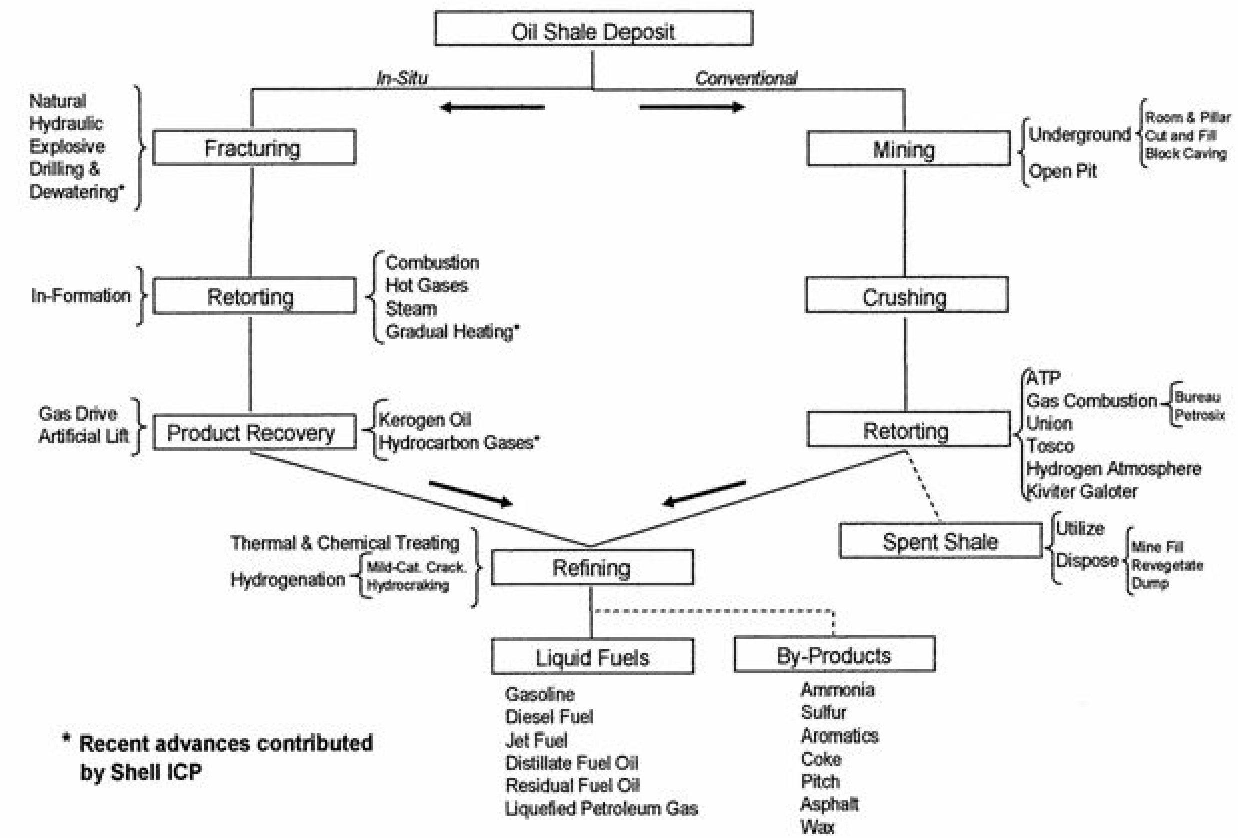

Fig. 4. Generalized Processes for Conversion of Shale to Fuels and Byproducts.
From Johnson H.R., Crawford P.M. and Bunger J.W. (2004)

1. Mining and retorting – traditional method of oil shale extraction (Alberta Taciuk Process – ATP) (Fig. 5). In order to obtain the fuel the oil shale has to «suffer» retorting at the surface (the current technology) or in -situ (experimental technologies). During retorting process oil shale is heated to temperatures of 350-375°C for the surface retorting and 175 °C for in- situ retorting. For at surface retorting oil shale is to be mined out. The shale excavated from mine varies extremely from several mm to larger than 1000 mm (crushing and screening have to be done before retorting). For some oil shale related to its smaller size, the heating rate is higher, the time required for retorting the oil shale is much shorter, only about several minutes or little more than ten minutes [Qian and Wang, 2006].

2. In-situ retorting – method to heat and undergo process of pyrolysis in-situ (In-situ Conversion Process - ICP) (Fig. 6, 7). Uniform heating of the oil shale to the wanted temperature produce a progressive oil shale recovery. Heating till 24 month before beginning of the sustained production the process will relatively slow and the output (light oil) quality better. In general, in-situ retorting has the advantage of deviating the oil shale mining, but has the disadvantages of lower oil yield and the environmental impact to ground water by shale oil and retorting water entrainment [Qian and Wang, 2006].

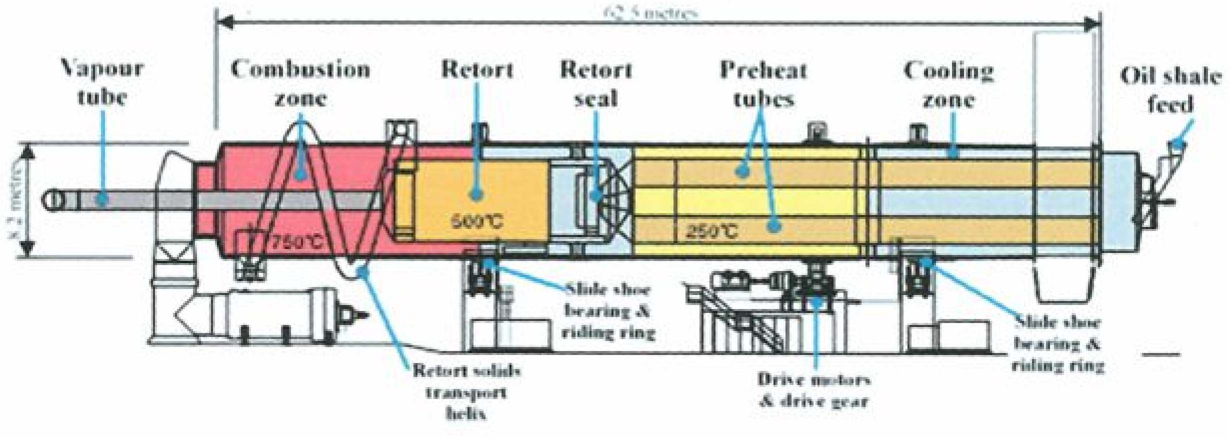

Fig. 5. ATP Schematic.
From Johnson H.R., Crawford P.M. and Bunger J.W. (2004)

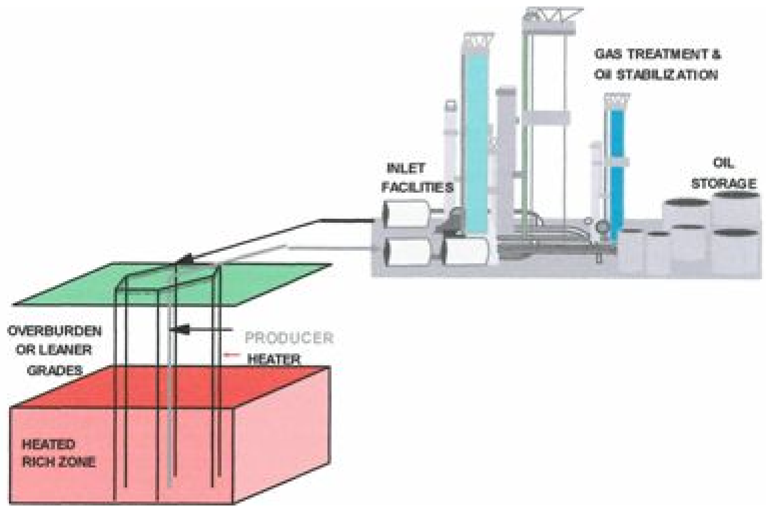

Fig. 6. Overview of in-situ conversion process.
From Johnson H.R., Crawford P.M. and Bunger J.W. (2004)

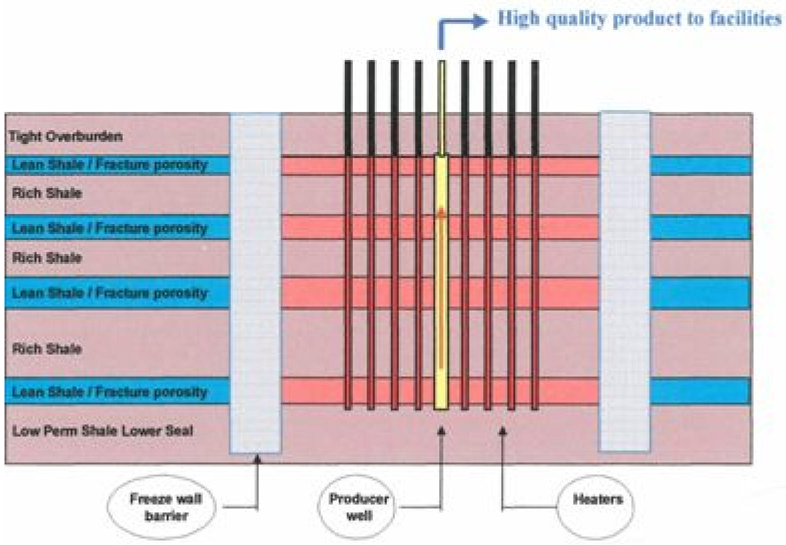

Fig. 7. In-situ Conversion Process detail.
From Johnson H.R., Crawford P.M. and Bunger J.W. (2004)

Most of the petroleum products we consume today are derived from conventional oil fields that produce oil and gas that have been naturally matured in the subsurface by being subjected to heat and pressure over very long periods of time. In general terms, the ICP accelerates this natural process of oil and gas maturation by literally tens of millions of years. This is accomplished by slow sub-surface heating of petroleum source rock containing kerogen, the precursor to oil and gas. This acceleration of natural processes is achieved by drilling holes into the resource, inserting electric resistance heaters into those heater holes and heating the subsurface to around 340-370 degree Celsius, over a 3 to 4 year period [Denning, 2012].

In 1996, Shell successfully carried out its first small field test on its privately owned Mahogany property in Rio Blanco County, Colorado some 200 miles west of Denver. Since then, Shell has carried out four additional related field tests at nearby sites. The most recent test was carried out over the past several months and produced in excess of 1,400 barrels of light oil plus associated gas from a very small test plot using the ICP technology (ibid).

Presenting the expectations for oil shale production, EIA (U.S. Energy Information Administration) estimated that because no commercial in-situ oil shale project has ever been built and operated, the cost of producing oil with this method is highly uncertain. Current estimates of future production costs range from at least dollars 70 to more than dollars 100 per barrel oil equivalent BOE in 2007 dollars .Therefore, future oil shale will depend on the rate of technological progress (currently the in-situ retorting techniques currently available require the production zone to be heated for 18 to 24 month before full-scale production can begin) and volatility of future oil prices. EIA (U.S. Energy Information Administration) estimated in 2009 that the earliest data for initiating of a commercial project concerning in-situ retorting is 2017. Thus, with the leasing, planning, permitting and construction in situ oil shale facility to require some 5 years, 2023 probably is the earliest initial date for first commercial production (ibid).

Both techniques – mining or retorting needs a lot of water for the oil shale production.

Red Leaf Resources, Inc. has developed the EcoShale™ In-Capsule Technology (Fig. 8) to economically and environmentally produce high quality liquid transportation fuels from oil shale, oil sands, coal, lignite and bio-mass. This technologies has been presented by the company on his site October 2012 - the method use to heat the mined shale in a closed surface impoundment or capsule. The process relies on conventional mining and construction methods and produces oil product that require no coking. Two products - oil and condensate - are produced: 1. prompt oil of approximately 29 API gravity, 2. condensate of approximately 39 API gravity. The technology requires no process water, protect groundwater and vegetation, uses low temperature for heating and allows for rapid site reclamation. Red Leaf Resources recently completed a successful field pilot demonstration of the EcoShale™ In-Capsule Technology in the Uintah Basin in Utah (ibid).

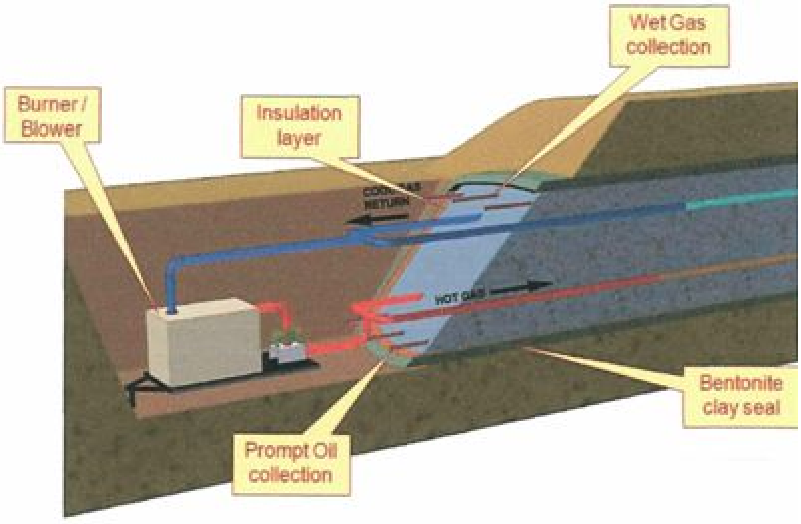

Fig. 8. The EcoShale In-Capsule Technology.
From Read Leaf Resources Inc. (2011)

Beckwith and Writer (2012) presented a rough of the planning capital costs for mining and surface retorting plants in United States. Considering mine development, upgrading and modest infrastructure expenditures a 50,000 barrel per day production, first-of-a-kind surface retorting complex will incur capital expenditure of between US 5 billion dollars and US 7 billion dollars (2005 dollars) and possibly higher than that. In fact, the process used to yield crude oil from oil shale – pyrolysis - has been assumed to take place during categenesis, -the conversion of buried organic matter to fossil fuels (thermal organic metamorphism).

Developing of oil shale needs that a huge range of factors are aligned economically and logistically: transportation and processing infrastructure and readily available water resources byproduct and spent shale handling, equitable air and water quality standards and regulations (ibid).

The greatest risks facing oil shale developing are higher production expenses and lower oil prices.

Global oil shale production

Oil shale has a long past of production, starting in 1837 in France (Autun mines, which were closed in 1957), Scotland 1850-1952, Australia 1865-1952, 1998-2004, Brazil 1881-1900, 1941-1957, 1972, Estonia 1921, Sweden 1921-1965, Switzerland 1921-1935, Spain 1922-1966, China 1929, South Africa 1935-1960 [Laherrere, 2005].

The AAPG - EMD Oil Shale Committee in the Semi–Annual Report (November 2011) announced that the total global production of shale oil (not included U.S.) is currently about 25,000 barrels per day (BOPD). Almost all of this production comes from mining and retorting activities in

Brazil, China and Estonia. Indications are that Chinese production, which was just over 10,000 BOPD, will increase to approximately 13,000 BOPD in 2011 for another decade. Current projections show that oil shale will not be a significant part of global production (>500,000 BOPD) for another decade. However, projects are in line over the next four to five years that could increase production significantly (ibid).

U.S. Energy Information Administration in the Annual Energy Outlook – 2011 - published the «Lower 48 Onshore» tight oil (low permeability reservoirs including shale and chalk) production. This production was as follows: 2009-0.25 MBPD (million barrels per day), 2010 - 0.37 MBPD, 2011 - 0.55 MBPD, and projected: 2012 - 0.72 MBPD, 2015 - 0.97 MBPD, 2020 - 1.20 MBPD, 2027 - 1.30 MBPD, 2030 - 1.32 MBPD.

In October 2012 in a press release published by UPI.com (Yergin/HIS, 2012) estimated that U.S. oil production from unconventional plays for 2012 is expected to reach 2 MBPD and to attain the 4.4 MBPD mark by 2020.

The recovery potential of the U.S. oil is generally estimated near 50% but may vary greatly.

For commercial production of the oil shale resources a large range of factors need to be economically, logistically and environmentally acceptable. Dyni and Johnson (2006) and Randal (2009) listed several question, which have to be elucidated before research and commercial development of oil shale begin:

What is the cost of energy required to heat the oil shale?

What is the amount of surface area that will be affected?

What about the disposal of produced water?

What about the potential for groundwater pollution?

What are the technology water demands?

What are the costs of development of the technology and what is the likely rate of the technology?

What are the potential employment and infrastructure needs associated with the technology?

What are the processing requirements for the shale oil produced by the technology, and how would this be done?

What are the environmental and health effects of the technology?

How would shale oil be transported from the proposal site to market?

All these factors severely restrict the amount of oil than can be extracted, regardless of the price of oil.

Till 2008 the oil shale has not been exploited in United States because the energy industry has viewed developing resource as economically unviable.

Andrews (2008) indicated that the production costs from first-of-a-kind commercial mining and surface retorting plants are estimated to be between $70 and $95 per barrel; very little R&D has been conducted at surface retorting since the early 1980s. For in–situ retorting costs might be competitive with crude oil priced at least than $30 per barrel, according to information released by Shell Oil (ibid).

Industry decisions on production to carry on initial commercial activity are at least six to eight years away (from 2008) and the production growth phase is not expected to commence before 10-20 years (from 2008), ibid.

Discussions and conclusions

Oil shale is an energy source still difficult to exploit economically. Dyni and Johnson (2006) have summarized the main issues related to oil shale developing: the higher cost of mining, the lack of viable technology to economically recover oil from shale and the cost of environmentally acceptable disposal of waste rock. Presently the oil shale production is a highly polluting activity, especially mining and refining damaging to the land, requires large amounts of water and their energy yield is low. These issues coupled with the cost of environmental restoration mean that oil shale extraction is only economically feasible when oil prices are high or during a world oil/fuel shortage period [Department of Energy, 2004]. Development of oil shale resources will require significant quantities of water for mine and plant operations, supporting infrastructure and associated economic growth .Initial process water requirements estimates of 2.1 to 5.0 barrels of water per barrel of oil, first developed in U.S. in 1971s, have declined. More current estimates based on update oil shale industry for new retorting method will be 1 to 3 barrel of water per barrel of oil. Peak World conventional oil supply will peak (peak oil is the point in time when the maximum rate of petroleum extraction is reached, after which the rate of production is expected to enter terminal decline); the only incertitude is when [Laherrère, 2007].

For a lot of countries the solution is to import more oil to increase energy conservation and efficiency and increasing domestic oil production. Lacking the adequate technologies to produce the continuous accumulations companies focused their interests exclusively to conventional reservoir. Discovering mid 1990s of two technologies, horizontal drilling and hydraulic fracturing permitted to petroleum companies to access resources from source rock and allowed the gas-shale resources developing.

The establishment of the new technologies and current increases in petroleum prices have induced the interest in development of oil shale worldwide. Many countries are watching the U.S.

(because the shale-gas and tight oil resources are more extensively characterized and commercially mature there) to see how it develops and oversees the use of horizontal drilling and hydraulic fracturing [Inglesby et al., 2012].

Global investors around the world have invested more than $40 billion in emerging unconventional gas and oil plays in the United States in order to gain the operational know-how required to develop shale plays in their own regions (ibid). However, it may be more challenging to develop unconventional resources in regions outside North America due to various factors, including geology, lack of pipeline infrastructure, regulatory and tax structure, and less developed upstream services industries. As an example the emergence of a shale-gas and tight-oil industry has been slow in Europe, where some governments have put moratoria on developing hydraulic fracturing until producers can guarantee greater levels of environmental safety (ibid).

Oil shale is still technologically difficult and expensive to produce - the potential negative impacts to the environment during development, the cost refining and transportation. The socioeconomic impacts are also issues of concern.

Producing oil from conventional petroleum system means finding and exploiting the existing oil reservoir; producing oil from continuous oil shale accumulations consists in outlining of kerogen (petroleum precursor) richest shale sections and generating oil from kerogen by pyrolysis. The oil, straight obtained from a conventional reservoir nowadays has to be generated in the future from oil shale accumulation by pyrolysis in surface retorting or in situ retorting

The «home-made» oil obtained by retorting from the oil shale continuous accumulation is genetically not very alike the conventional crude oil (the liquid hydrocarbons has been produced from kerogen).

Developing oil shale accumulations means to face huge challenges but an efficient oil shale development can be accomplished and an acceptable (concerning environmental and health effects); oil shale industry based on new technologies can be build nowadays.

However [Laherrère, 2005] noted**:** «*Oil shale and shale oil have a very disappointing past and an unlikely future!*

The Middle Eocene Green River Formation (Colorado, Wyoming and Utah) contains the largest oil shale deposits in the world.

No wonder that a popular saying in Western Colorado asserts – Oil shale is the fuel of the future and always will be!

May be they are right!».

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