Boss Energy Limited

Report for Latrobe Oil Shale Resource

Technology Screening Study

August 2009

INFRASTRUCTURE | MINING & INDUSTRY | DEFENCE | PROPERTY & BUILDINGS | ENVIRONMENT

Contents

Table Index

Figure Index

Appendices

A Boss Energy Report on Bulk Sample China Flats

Executive Summary

Oil Shale is a potential fuel source of the future. It is often a misnomer as the mineral is neither oil nor shale. The carbon rich component known as kerogen is embedded within the mineral matrix. Shale was discovered in the 1600s and used as fuel similar to coal. It is only with the advent of today's petroleum based economy that oil from shale was considered. The two major uses for shale are generation of power and extraction of oil. Other uses include utilising the spent shale synergistically with other industry, asphalting roads and to make paint.

Boss Energy holds rights to an oil shale resource in Tasmania. This resource contains 42 million tonnes of shale at a shallow depth with another 30 million tonnes at deeper. The median grade of the oil shale is 130 litres of raw shale oil per tonne of dry shale with a high of 300 litres per dry tonne. Conservatively, this equates to a possible 50 million barrels of raw shale oil.

Boss Energy has engaged GHD to conduct a Technology Screening Study to determine suitable technologies for developing the resource. The study included researching and evaluating available shale to liquid technologies to identify those that were suitable for the resource and generally commercially proven. Other opportunities for Boss Energy to monetise the resource were also identified.

Over 100 technologies were considered in the technology review. From the shale to oil perspective, the Estonian TSK and Petrosix processes are considered the frontrunners. Further investigation of these technologies, which would involve a more in-depth technical and economic evaluation of various options, would be carried out in the next phase. Consultations with stakeholders to understand synergies, influences, commercial return and benefits of other options would assist in proving direction to the next phase.

Developing a resource to commercial status could reflect a timeline of 5-10 years, even if the development is based on an established process. Other technologies are under development. The opportunity to leverage newer and more appropriate technologies should they arise is not precluded.

Toll treating as a commercial model can not be discounted. Detailed investigation into toll treating was beyond the scope of this study. Mining and exporting the shale to another location, for whatever use, should not be ruled out.

A synergistic relationship between the shale processor and another industry is another option. The shale could be combusted completely to provide power at competitive rates to local industry, and the ash utilised elsewhere. Others have studied utilising the ash in the cement industry or to make bricks.

The research carried out for this study reaffirms that Oil Shale is an important mineral resource that is increasingly being recognised as a source of energy. Billions of dollars have been invested worldwide in Research and Development and billions are still being spent.

1. Introduction

Boss Energy's Latrobe oil shale project is based on a resource of Tasmanian oil shale located between Latrobe and Railton, 10 kilometres south-west of the port of Devonport. The Latrobe oil project has a JORC indicated resource of 42 million tonnes of Tasmanite oil shale of which approximately 6 million tonnes is at less than 20 metres depth and amenable to open cut mining methods. An additional JORC compliant inferred resource of 30 million tonnes of Tasmanite oil shale is estimated [4].

Boss Energy (BE) has indicated a desire to monetise the resource as early as possible. To this end BE engaged GHD to undertake a review of available technologies that could be suitable for Tasmanite (Tasmanian Oil Shale), the shale present in the Latrobe resource. A secondary objective is to consider other opportunities for monetising the resource.

The history of extraction of oil from shale goes back more than 100 years [1]. Over the past hundred years, in the U.S., the development of shale has been intermittent. Although considerable investment has been made oil from shale has not reached sustained commercial quantities owing to availability and price of crude oil.

The number of processes has been limited by a constraining the study to processes that are suitable to similar shales and mining techniques.

The table below represents the history of oil shale development in the US. Similar developments have occurred worldwide leading to a plethora of processes. The research carried out for this study has indicated close to 100 processes that claim to be able to extract oil from shale. This study was a measured approach and focuses on those processes that have a history and for which verifiable information is available in the public domain. This evidence should necessarily be of the form of Government reports/publications and peer reviewed journal articles. We have also drawn upon internal GHD reports to support this study.

The study highlights those processes that are relevant to Tasmanite and then evaluate them against a set of parameters that best reflect the way forward for BE

Table 1.1 below is a brief history.

Table 1.1 History of US Shale Development [18]

Year	Milestone
1909	U.S. Government creates U.S. Naval Oil Shale Reserve
1910	Oil shale lands "claim-staked"
1916	USGS estimates 40 B Bbls of shale oil in Green River formation in CO, WY, and UT
1917	First oil shale retort kiln in DeBeque, Co.
1918	First oil shale boom begins with over 30 0 mining clams; lasts until 1925
1920	Mineral Leasing Act requires shale lands be leased through the Secretary of Interior
1929	Test retort at Rulison stops at 3 600 bbls after oil discoveries in CA, TX, and OK
1944	U.S. Synthetic Liquid Fuels Act provides 18 million for experiments at Anvil Points

Year	Milestone
1950s	Gulf Oil and Shell Oil both purchase oil shale lands in Green River formation
1956	Anvil Points operations cease after testing three experimental retort processes
1961	Unocal shuts down Parachute Creek "Union A" retort after 18 months and 800b/d due to cost
1964	Colorado School of Mines leases Anvil Points facility to conduct research on US Bureau of Mines Gas Combustion Retorts
1967	CER and U.S. AEC abandon plans for "Project Bronco" atomic subsurface retort 3
1972	Tosco, Sohio and Cleveland Cliffs halt Colony oil shale project begun in 1964 after 270000 bblof production
1972	Occidental Petroleum conducts first of six in-situ oil shale experiments at Logan Wash
1972	Paraho is formed as a consortium of 17 companies, obtains a lease of Anvil Points facility and builds and operates 24 ton/day pilot plant and 240 ton/day semi-works plant.
1970s	Shell researches Piceance Creek in-situ steam injection process for oil shale and nahcolite
1974	Four oil shale leases issued by BLM under Interior's Prototype Leasing Program.
1974	Unocal develops new "Union B" retort process; Shell and Ashland join Colony Project
1976	Navy contracts with Paraho to produce 100 0 barrels of shale oil for testing as a military fuel
1976	Unocal begins planning commercial scale plant at Parachute Creek to be built when investment is economic; imported oil prices reach $41/bbl
1977	Superior Oil abandons plan for Meeker oil shale plant planned since 1972
1979	Shell, Ashland, Cleveland Cliffs and Sohio sell interests in Colony to ARCO and Tosco;
	Shell sells leases to Occidental and Tenneco
1979	Congress passes Energy Security Act, establishing U.S. Synthetic Fuels Corporation; authorises up to 88 Billion for synthetic fuels projects, including oil shale.
1980	Exxon buys Arco's Colony interest and in 1981 begins Colony II construction, designed for 470 b/d using Tosco II retort process
1980	Congress approves 14 billion for synthetic fuels development
1980	Unocal plans Long Ridge 500 b/d plant applying "Union B" retort; begins construction in 1981
1980	Amoco Rio Blanco produces 1900 bbls of in-situ oil at C-a tract
1981	Exxon begins to build Battlement Mesa company town for oil shale workers
1981	Second Rio Blanco in-situ retort demonstration produces 24 400 bbls of shale oil
1982	Oil demand falls and crude oil prices collapse
1982	Exxon Black Sunday: announces closure of Colony II due to cost and lower demand
1982	Shell continues in-situ experiments at Red Pinnacle and labs through 1983
1985	Congress abolishes Synthetic Liquid Fuels Program after 40 years and 8 billion
1987	Shell purchases Ertl-Mahogany and Pacific tracts in Colorado
1987	Paraho reorganizes as New Paraho and begins production of SOMAT asphalt additive used in test strips in 5 States.
1990	Exxon sells Battlement Mesa for retirement community
1991	Occidental closes C-b tract project before first retort begins operation
1991	Unocal closes Long Ridge after 5 MM bbls and 10 years for operational issues and losses

Year	Milestone
1991	LLNL plans 20 million experiment plant at Parachute; Congress halts test funds in 1993
1991	New PARAHO reports successful tests of SOMAT shale oil asphalt additive
1997	DOE cedes oil shale lands to DOI/BLM
1997	Shell tests in-situ heating on Mahogany property; defers further work on economic basis
2000	BLM seeks public comment on management of oil shale lands
2000	Shell returns to Mahogany with expanded in-situ heating technology research plan (ongoing)
2004	DOE Office of Naval Petroleum and Oil Shale Reserves initiates study of the strategic significance

.

2. Comparison of Shales

The term Oil Shale is a misnomer as the rock is neither shale nor oil. The organic component of the shale that yields oil is known as kerogen and is often found as a matrix bound within the material of the sedimentary rock. Kerogen is organic matter that is on the way to becoming oil. Shale such as tasmanite shares some characteristics with coal.

Several studies have been carried out over the past 60-70 years to understand oil shale and the nature of kerogen. Broad classifications are based on the source of the kerogen (plant material or animal based). Lacurstine (occurring in a lake) shales are generally plant based and include a class of shales known as torbanites. Torbanites are algal-based shales that have high carbon content [10].

The hydrocarbon component of oil shale is kerogen and is not clearly understood. There are several empirical formulae but these are not particularly helpful [35]. Essentially the major components of kerogen are Carbon, Hydrogen, Nitrogen, Sulphur and Oxygen. What is important is that when kerogen is denatured it produces oil (known as shale oil) and fuel gas. The solid residue known as spent shale contains char (unconverted kerogen). Depending on where they are found, shales possess free and bound moisture, and concentrations vary significantly between locations. Water is thus a necessary by product from the denaturing of shale by heat. Geological classification is not as important as understanding the chemical characteristics of a particular shale.

The richness of shale or Grade is determined by its oil content and this is reported as a percentage or as “Litres per Tonne Zero Moisture” (LT0M) or “Gallons per Ton (GPT). This is determined by a Modified Fischer Assay where a predetermined quantity of dried (all the free moisture is removed) shale (-100 mesh) is heated to and maintained at 500^{o}C for 4 hours. The oil, gas and water collected determine the LT0M, gas and loss, and bound moisture (also known as water of hydration or retort moisture).

2.1 Shales from around the world

The USA, Australia, Estonia and Brazil have very large resources of oil shale and some started using their resources as an alternative source for transport fuel or power starting with the first retort in Scotland in the 1859 [22] to the current spread of retorts and other technologies across the world.

Table 2.1represents shales from around the world including tasmanite. This list is not exhaustive as there are too many types to enumerate. There are three columns for tasmanite as information has been sourced from three separate references.

This table highlights the differences between shales and supports the rationale for a processing technology to be tailored for specific shale. Different shales may require different operating conditions, upstream and downstream processing and waste treatments. The reported grade of shale in the table should be considered carefully. The grade can vary across a deposit and in order to maintain a constant feed to the process, blending across the deposit is considered. The grade reported for the Alpha resource suggests that it is a pure torbanite. Hutton et al [14] have reported the Alpha resource having an ash content of only 4.4% and an assay in excess of 600 LT0M for the sample under consideration.

One dataset shows very high sulphur content for tasmanite. Although significant, studies on other shales have shown that 60 to 90% of the sulphur could report to the ash.

Shales behave differently under retorting conditions. Some shales have a tendency to form clinkers, others tend to produce fines that are carried over and clog the oil recovery section. The presence of high amounts of free and bound moisture could load the retort forcing lower flow rates and increased energy costs, consequently there would also be an issue with clean up of the sour water and gases.

Different minerals present in shale also contribute to the manner in which shale behaves during pyrolysis.

Carbonates present in shale could encounter carbonate decomposition close to 100%, and this could lead to increased carbon dioxide emissions presenting climate change challenges, but also opportunity for geo-sequestration and more modern innovative technologies such as bio sequestration through the use of microalgae.

An important conclusion drawn from the above discussion is that while a technology may appear feasible, it is critical to evaluate that technology with the specific shale to be processed. Sometimes this could mean engineering modifications to the process equipment.

Table 2.1 Oil Shale Compositions [2]

	Timahdit Morocco	Irati Brazil	Colorado USA	Nagoorin Qld, Aus	Condor/McF Qld, Aus	Alpha Qld, Aus	Maoming China	Israeli	Kukersite Estonia	Tasmanite Tas, Aus	Tasmanite [17]	Tasmanite	Tasmanite
Fischer Assay													
Oil weight, %	6-9	6-12	16.5	14.1	6.3	52	9.7	6.2	28.6				
Water (bound), %	2.1-2.7	0.2-2.1	1	6.9	1.9	4	3.8	5.8	2.5				0.8
Spent Shale, %	85-83	83-90	78.6	72.4	87.3	33	82	87.4	62.7			83.4	62.5
Gas + Loss, %	2.8-3.7	2-4	3.8	6.6	4.5	11	4.5	3.6	6.2				30.84
LT0M/Fixed Carbon, %	79.9	101.8	187.4	157.4	72.1	588.7	111.7	64.8	305.9		5, 130, 300	120	5.86
Other properties													
Moisture, wt%	6.7-9.8	0.2-6	0.7	23.2	7.7	2.8	11.3	8.1	5.8			6.3	
Specific Gravity	1.88-1.99	1.9-2.1	1.94	1.47	2.05	1.16	1.73	1.57	1.6				
GHV, cal/g	1.25-1.65	1.3-1.67	2.178	2.856	1.12	7.33	2.05	1.006	3.84				
C, %	14.78-19.46	12-17	23.45	25.67	10.5	70.54	18.74	15.5	36.8			30.76	
H, %	1.9-2.0	0.9-2.4	2.9	3.7	1.7	8.39	2.9	1.6	4.3			4.23	
S, %	2.1-2.7	3.9-5.6	1.1	1	0.9	1.1	1.6	2.9	2			17.17	2.56

	Timahdit Morocco	Irati Brazil	Colorado USA	Nagoorin Qld, Aus	Condor/McF Qld, Aus	Alpha Qld, Aus	Maoming China	Israeli	Kukersite Estonia	Tasmanite Tas, Aus	Tasmanite [17]	Tasmanite	Tasmanite
N, %	0.46-0.63	0.3-1.9	0.6		0.3	1	1.3		0.1			1.05	
O, % (normally by difference)												1.31	
Loss on ignition at 950°C	31.4-38.9	20-24	38	41.9	18.6	91.7	32		56.2				
Ash composition													
SiO_2, %	31.6-37.5	50-56	45.2	64.8	73.2	53.4	57.2		33.2	70-77			
Fe_2O_3, %	3.5-5.8	7.6-9.8	5.5	10.7	8.1	9.9	12.2		6.6	5-7			
Al_2O_3, %	8.6-13	9.8-12.6	2.3	12.5	12.1	24.3	19.5		8.9	11-16			
CaO, %	15.7-26.7	1.3-3.9	18.9	1.9	2	3.4	1.1		33.7	0.4-4			
MgO, %	5.6-7.4	2.0-3.7	17.4	1.6	1	4.1	0.8		9.5	0.7-0.3			
SO_3										0.4-2			
K_2O										2-3			
Na_2O										0.5-2			
Fischer Assay Oil													
Specific Gravity at 20C	0.962	0.906	0.902	0.918	0.895	0.905	0.89	0.98	0.958	0.854	0.934		

	Timahdit Morocco	Irati Brazil	Colorado USA	Nagoorin Qld, Aus	Condor/McF Qld, Aus	Alpha Qld, Aus	Maoming China	Israeli	Kukersite Estonia	Tasmanite Tas, Aus	Tasmanite [17]	Tasmanite	Tasmanite
C, %	78.73	84.6	84.21	83.4	84.72	84.32	84.81	80.8	84				79.34
H, %	9.69	12.5	11.29	11.37	12.54	11.89	11.65	10.4	10.7				10.41
S, %	6.33	1.1	0.92	1.16	0.46	1.72	0.52	5	0.7	2.22			4.93
N, %	1.52	0.9	1.78	1.18	1.3	0.69	2.6	1.2	0.1	0.34			0.31
O,% (by difference)	3.73	0.9	1.8	2.89	0.98	1.38	0.42	2.6	4.5				4.93
GHV, cal/g	9.578	10.169	10.211	10.294	10.2	10.167	10.145	9.5	9.51				

2.2 Tasmanite of the Latrobe Resource

Tasmanite is generally classed as a torbanite and found between Latrobe and Railton in Tasmania. This shale has a LT0M that ranges between 130 and 300 and appears to be similar to kukersite from Estonia. It has similar ash content and appears to have a large volatile component.

There is some confusion regarding the nature of Latrobe Oil Shale with some literature classifying it as a torbanite. Tasmanite of the Latrobe resource is algal-based similar to torbanites elsewhere. The difference between the Latrobe resource and other torbanites is the percentage of ash in the resource. A rich torbanite would contain close to 80% carbon if not higher and would be similar to coal in it is characteristics. Latrobe shale on the other hand is a torbanite that contains about 70% of ash. In a report by the Director of Mines, Tasmania in 1926 [27], the composition of tasmanite is moisture 0.8%, volatile matter 30.84%, fixed carbon 5.86%, sulphur 2.56% and ash 62.50%. It is important to recognise that the Latrobe oil shale resource has considerably greater ash content than other torbanites. This higher ash content affects the behaviour and products on retorting, and explains the difference in behaviour during retorting between true torbanites and tasmanite.

The work by Han et al [10] has stated torbanite and cannel coals are "*considered coals owing to their low mineral content and physical morphology*." Torbanite is also known as boghead coal. Torbanite and cannel coal are end members in the classification scheme of coal owing to the low ash yields. The Latrobe resource on the other hand is a pseudo torbanite having properties between a true torbanite and traditional oil shale.

Some of the earliest work on quantifying and qualifying the Latrobe resource is found in the archives of the Tasmanian Government dating back to the 1920s [27].

From a physical examination it may appear that tasmanite chemistry may be different to other shales, however this is not case, but it has a rank lower than algal shales (Kane, [17]).

The Tasmanian Government Geologist [28] presented a short report on the Latrobe resource that stated that the oil shale was very rich. He has presented the results of studies that have differently stated the resource having an oil content between 29 and 50 gallons per ton (GPT); 44 to 65 GPT; and others from 11.4 to 65 GPT. The units are not clear from the report. Noting that GPT is an American way of reporting, an average 41 GPT is about 170 litres per tonne.

Recent Studies by Boss Energy have indicated that the resource could be as rich as 422 litres per tonne. Their indicative results have a mean of about 203 litres per tonne. While Boss Energy's results are not conclusive, they show that the shale is a rich resource and the results are comparable to data from earlier studies.

Tasmanite has higher ash content than kukersite; tasmanite ash appears to be mainly sand (SiO_2) whereas kukersite ash contains significant amount of calcium oxide implying carbonate decomposition during retorting and CO_2 emissions consequently.

In the reported data on oil compositions, sulphur and nitrogen are significantly higher. Sulphur is between 3 and 7 times more (2.22 to 4.93%) and nitrogen about 3 times more than kukersite oil. This implies that tasmanite oil may be subject to harsher stabilising/ hydrotreating to remove the nitrogen and sulphur and a higher load on the sulphur recovery unit.

Interestingly the high carbon content of the shale may suggest other options with the shale such as gasification. This has not been explored before.

Figure 2.1 Kukersite (left) and Tasmanite (right) (source: http://www.envir.ee and www.bossenergy.com)

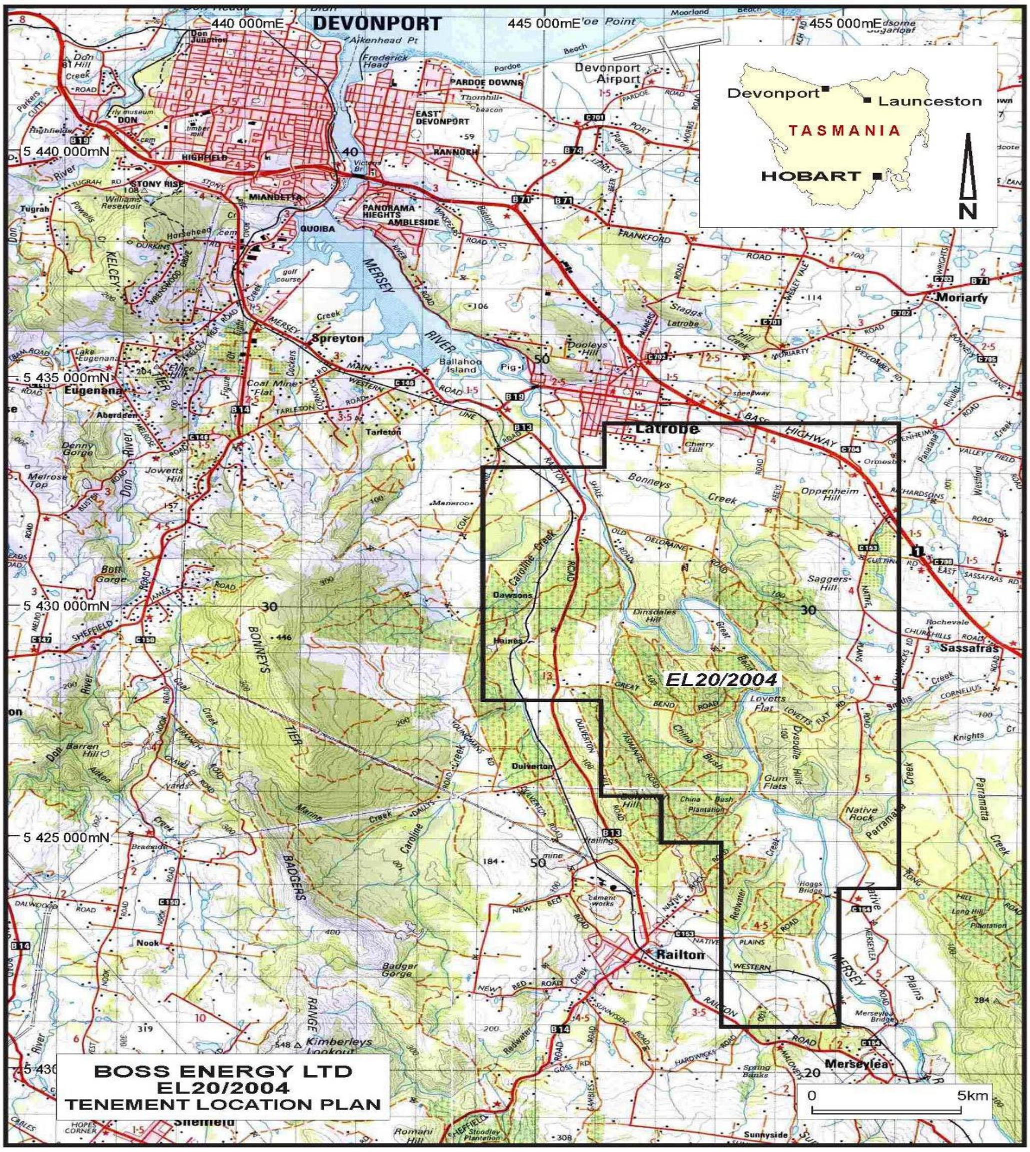

Figure 2.2 Boss Energy's Latrobe Resource

Boss Energy carried out a bulk-sampling program on their resource at China bush. A sample just less than 1000 tonnes were extracted from an area 450 square metres. The specific gravity of the shale is 2.1 g/cc and the shale concentration is 2.1 tonnes per square metre. It is worth noting that the excavation of the shale was accomplished by standard earth moving equipment; in this instance a 22 tonne excavator rock-breaker and trucks for transport of material to a stockpile. Figure 2.2 below shows Boss Energy's resource and the specific sampling area.

The sequence of photographs below show the mine ready for extraction, the shale stockpile and the rehabilitated mine.

Figure 2.3 Prepared Mine (ready for extraction)

Figure 2.4 Shale Stockpile

Figure 2.5 Backfilled pit with topsoil added

The sampling program has also shown that the shallow resource is easy and safe to mine. Safe rehabilitation of the mine is readily achieved. The resource can be mined selectively and this has the potential to reduce the footprint of the mining operation.

To summarise it is worth reiterating that Boss Energy's Latrobe Oil Shale resource is world class. Not only does this shale have a high-energy value (about 5-8 GJ/tonne) but is also easily extracted from the ground. In terms oil potential it is a rich oil shale.

3. Shale Technologies

The classification of shale technologies is done on several bases. Common classifications include Ex-Situ (implying mining and preparing the shale prior to processing) versus In-Situ (Processing the shale without mining). Further classification includes the mode of heat addition; the size of particles being processed; the overarching technology – e.g. retorting, microwave.

Owing to the low depth of Tasmanian Shales (between 5 and 10 metres) and that in-situ processes are still at an experimental phase, the focus of the study has been on Ex-situ processes. This study does not imply that in-situ may not work, only that at this time there is insufficient evidence to prove commercial viability. Almost all the effort on in-situ release of oil has been in the US, with majors such as Shell spending considerable sums on the process before suspending it.

Ex-situ or above ground processes on the other hand have been around for over 100 years and in different countries, USA, Brazil, Australia, China and Estonia to name a few. Figure 3.1 shows the overall process of shale to liquid.

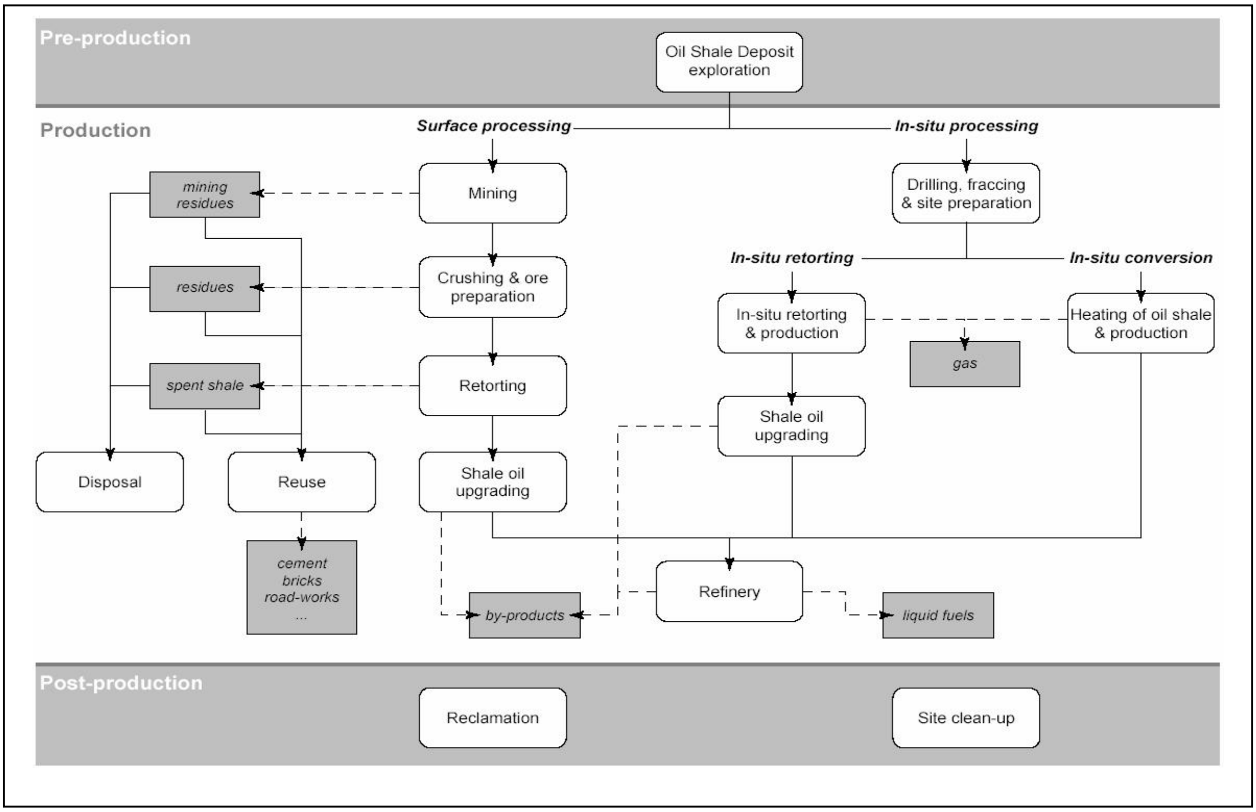

Figure 3.1 Snapshot of shale to liquid [8]

For discussion, shale technologies have been grouped as:

- Retorting
- Solids-based heating
- Heat transfer by other means

» Alternative processes

3.1 Retorting Processes

In all retorting processes, the shale is heated either externally or internally to release the oil and gases from kerogen by a process known as pyrolysis. Pyrolysis occurs between 450 and 500°C and is an endothermic process. Owing to the heat of pyrolysis, some mineral decomposition occurs. Not all the kerogen gets pyrolysed. Some processes use the remaining kerogen on the spent shale known as char as a means to provide heat energy by combusting the char. The char is similar to activated carbon. Generally, retorting processes are *lump processes* implying a particle size in the range 6 to 75 mm, in some instances the upper end could be 125 mm.

In the simplest form, a retort is a vertical cylindrical kiln similar to a lime kiln. Oil Shale is added at the top, gas, oil and water are taken off as a top draw and recovered in an oil recovery section. The spent shale is generally returned to the mine. All retorts generally have a drying zone, pre heating zone, pyrolysis (and combustion) and cooling zone.

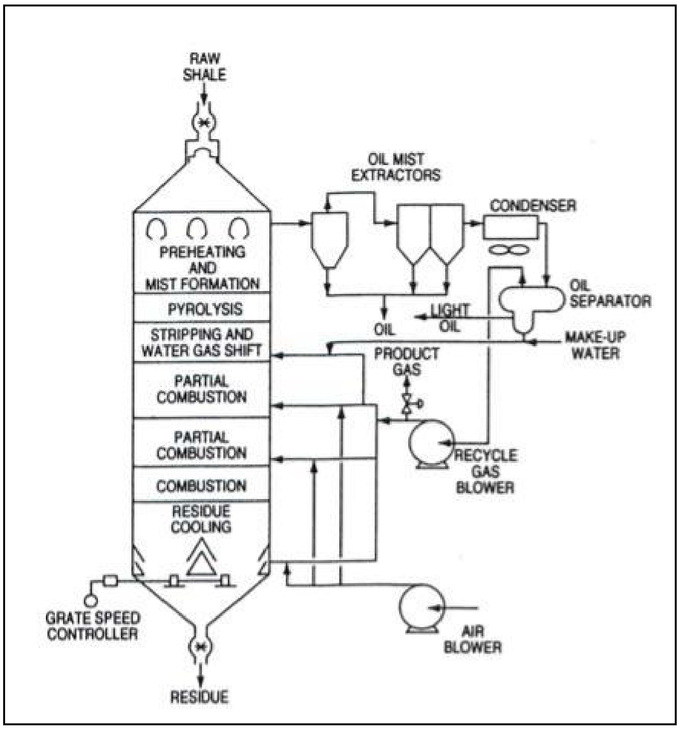

Figure 3.2 A typical gas retort with oil recovery [31]

Thus, all retorting processes share similar upstream requirements of mining; crushing; maybe drying; and downstream processes of oil upgrading; gas cleaning; water treatment; and spent shale disposal. Some of the more common retorting processes are described here.

3.1.1 Paraho Indirect/Direct

Indirect

The Paraho retort is a vertical kiln where shale is added at the top and spent shale withdrawn at the bottom. The gas generated from retorting, after recovery of oil and water is heated to above the pyrolysis temperature and fed back into the retort at predetermined locations. Part of the recycle gas is introduced at the bottom of the retort to recover heat from the spent shale.

Spent shale discharges at the bottom of the retort. The overhead products from the retort are sent to an oil recovery section where the raw oil, raw water and gas are separated.

In this mode not all the kerogen is utilised and char remains unutilised. This does not imply that yields are lower; rather it suggests that heating potential of char is lost and must be taken up by the recycle gas.

Direct

The only difference between direct and indirect is the way heat is added to the retort. Heat is added internally by the combustion of char within the retort by injecting a mixture of air and recycle gas. This heat of combustion is more than adequate for pyrolysis and the products. Generally the product gas from direct mode has a lower calorific value as it is diluted by the nitrogen in air.

The Paraho technology was successfully trialled in Colorado at a 1 tph pilot scale and 10 tph semi-works scale on Colorado shale. The oil from this process was upgraded and successfully tested on a diverse range of naval vehicles (including aircraft).

Queensland Energy Resources are currently pursuing the Paraho II Technology to process their deposits in Queensland (http://www.qer.com.au).

3.1.2 Petrosix

The Petrosix retorting process is owned and developed by Petrobras, the Brazilian Oil Company. It is a precursor to the Paraho process. The Petrosix retort has a capacity of 260 tph and runs in indirect mode. It has been optimised over a period several years for Irati Shale.

The operation of the retort is similar to the Paraho process operating in indirect mode. The shale enters at the top of the retort with a side draw for the oil, gases and water vapour. The mixture enters an oil recovery section where the oil is recovered; a slip stream of gas leaves the process as product gas; and the remaining gas gets heated and is fed back to the retort to provide the heat of pyrolysis. The spent shale discharges out of the retort into a water bath. The water bath forms a water seal while also cooling the spent shale to a safe disposal temperature. Spent shale can absorb up to about 12% free moisture.

Petrosix has recently entered into a Joint Venture with Oil Shale Exploration Company in Utah to conduct trials on their shale (http://www.osec.com). Petrosix do not license their technology and only enter into joint ventures.

In one of the few papers in the public domain [2], the Petrosix story is told over 40 years. The current process is the end result of a series of improvements. They also have a pilot plant facility on site.

3.1.3 Kiviter

Similar to the Paraho process, oil shale is added at the top and spent shale withdrawn at the bottom. The char is burnt in the lower part of the retort and gas is added at the bottom to cool the spent shale. The rising hot gases provide the heat for pyrolysis. The gases and oil are sent to an oil recovery section and the oil and water free gas is sent back to the retort. The spent shale discharges through a water seal.

Currently operated by Veeru Keemia Grup (VKG) in Estonia, this technology has evolved over 87 years. Throughput is of the order of 40 tph and yield (% of MFA) is low of the order of 75%. Multiple retorts have been used.

3.1.4 Fushun Process

The Fushun process is similar to the Kiviter process, however a collection of retorts are linked to one oil recovery system and one heat supply system. The shale enters from the top of the retort and the hot product gases are sent to an oil recovery system. 20 retorts are linked to one oil recovery system. After dropping off the oil and water, the gases are heated in furnaces (two working in tandem, standby and active) and the hot gases are recycled to the retorts; the air stream combusts the char on the spent shale and together with the hot gases provides enough heat for pyrolysis. Retorts are 10 metres tall and 3 metres in diameter. Spent shale discharges through water seals. Literature suggests that currently 140 retorts are in operation, and more are planned. It has low water efficiency owing to the water seal and uses about 6 to 7 barrels of water per barrel of oil produced. Yields are about 65% and the technology has been evolving over the past 79 years. There are indications that Jordan is considering the adoption of Fushun retorting technology.

Other notable retorting processes include Union A and B, Superior Direct and Indirect. At the fundamental level all retorting processes are similar; the differences are in the manner in which heat is added for pyrolysis and the manner in which oil and gas are recovered. It should be noted that very often modifications have been made to suit a particular shale type.

Recycle gas has a similar specific heat to shale hence a weakness of retorting processes is the large amount of gas that is required to circulate in the system. As the processes are atmospheric, the heat volumetric flows are huge. Compression costs can be quite significant unless managed with low pressure drop systems.

3.1.5 Retorting of Torbanites

South Africa has extensive torbanite deposits that are low in ash. In the January 2009 edition of The Energy Journal (http://www.cefgroup.co.za), CEF was completing a bankable feasibility study to produce 10,000 barrels of fuel per stream day for 20 years from torbanite. A literature search did not yield specifics of oil production from torbanite other than suggest retorting as an option. It is suspected that the retorting of torbanites would be similar to retorting of typical shale. The torbanite (coal) is heated in an oxygen-depleted environment until the tars and volatiles are released. The oil is recovered in an oil recovery system, and then processed.

Ambre Energy (http://www.ambreenergy.com) is trialling a similar process where coal is fed at the top and heated along the vertical retort. Hot char leaves the retort at the bottom that is then used for power generation. The released gases are used to produce dimethyl ether (DME).

There have been some retorting trials on the Alpha deposit (grade is greater than 600 litres per tonne) as has been discussed in the paper by Hutton et al (1996) [14]. The torbanite needs to be rich for this retorting to be successful.

3.2 Solids based heating

Where heat of pyrolysis is added by other solids, the process generally requires shale to be *fines* ($0<D_p<25$ mm). The smaller particle size ensures lower residence times and theoretically all the kerogen can get converted to oil and gas. The greater surface area while having pyrolysis advantages has mechanical implications. There is a cost associated with crushing and grinding shale to the desired size and spent shale management and disposal.

3.2.1 Alberta Taciuk Process (ATP)

Also known as the AOSTRA Taciuk Process, this was process was invented by Bill Taciuk to treat oily sludge, tar sands and shale. A demonstration plant was constructed in Australia with a capacity of 210 tph. It ran for 5 years before negative public perception and financial issues forced its closure.

Shale enters the retort and passing through a drying zone where the moisture is released as steam; it gets heated further by the returning ash and flue gases; the shale then enters the reaction zone where it gets pyrolysed. The heat for pyrolysis is obtained by the combustion of spent shale on the outside of the reaction chamber. The char moves along the outside of the rotating kiln until it discharges. Along the way it exchanges heat with the entering shale.

The hot hydrocarbons leave the rotating kiln and enter the oil recovery section. The ATP is a fines processor (<10 mm particle diameter). The ATP needs proper ancillary support for it to run well.

The ATP technology has been proven at a demonstration scale; however, there is no commercial retort available in the market today. While reports indicate that the ATP may be introduced in Fushun and Jordan, it is only a successfully demonstrated technology not proven commercially.

One could speculate that the ATP may not have succeeded, as ancillary equipment may not have been able to support the processor.

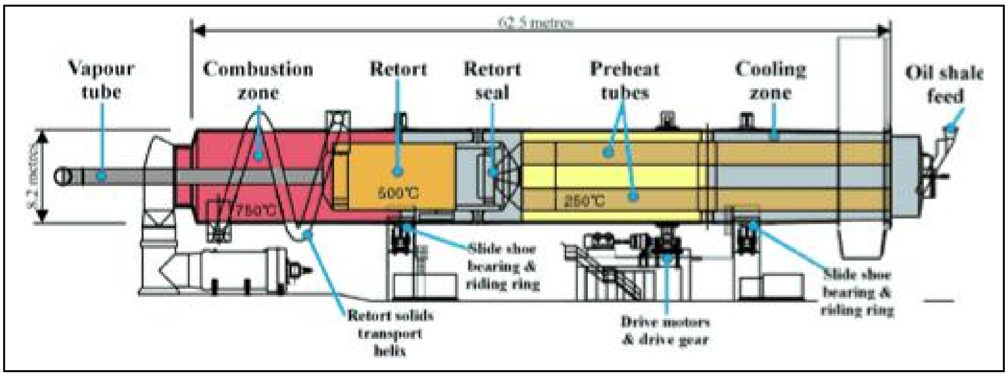

Figure 3.3 The ATP Processor [31]

3.2.2 The TSK Process

While similar to the ATP process, the main advantage is the separation of the unit operations. This is a fines process. The fines are sent to a dryer where the incoming shale is dried by the flue gases from the combustion of char. The hot ash from combustion of the char is separated from the flue gases and then mixed with the dry shale before entering the drum reactor. The vapours are sent to an oil recovery section where the oil and product gas is recovered.

The ash and char enter the combustor where the hot stack gases and ash (after combusting the char) are sent to a cyclone. The stack gases continue on to heat and dry the incoming shale before leaving the process through stacks. Thus the process is fairly self-contained and self perpetuating. There are issues of heat integration and emissions but these are recognised by the company and are being worked through. They state on their website that they are constructing a new plant of capacity 5,500 barrels/day with reduced emissions and improved efficiency.

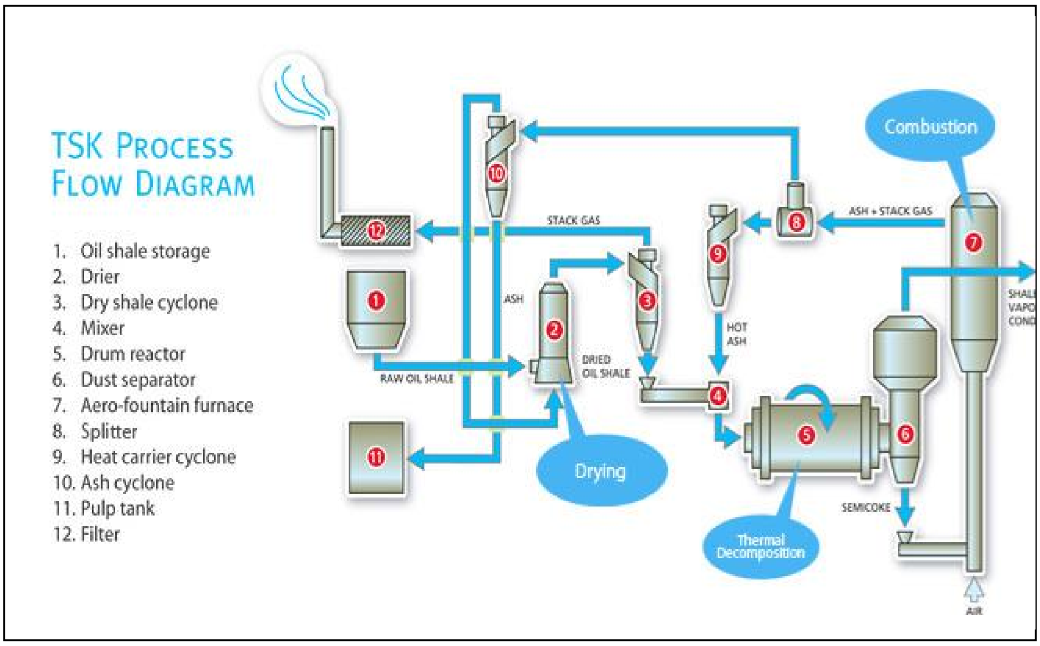

Figure 3.4 The TSK process (source: http://www.shaleoil.ee/index.php?id=132)

3.2.3 The TOSCO II process

In this process the heat transfer is by means of heated ceramic balls. The fine shale is lifted through lift pipes by hot gases into the pyrolysis chamber where it gets mixed with the hot ceramic balls that have been heated by the combustion of shale gas to about 1100°C. The shale pyrolysis and the spent shale and balls enter a trommel where the shale drops off and the ceramic balls are returned to be heated.

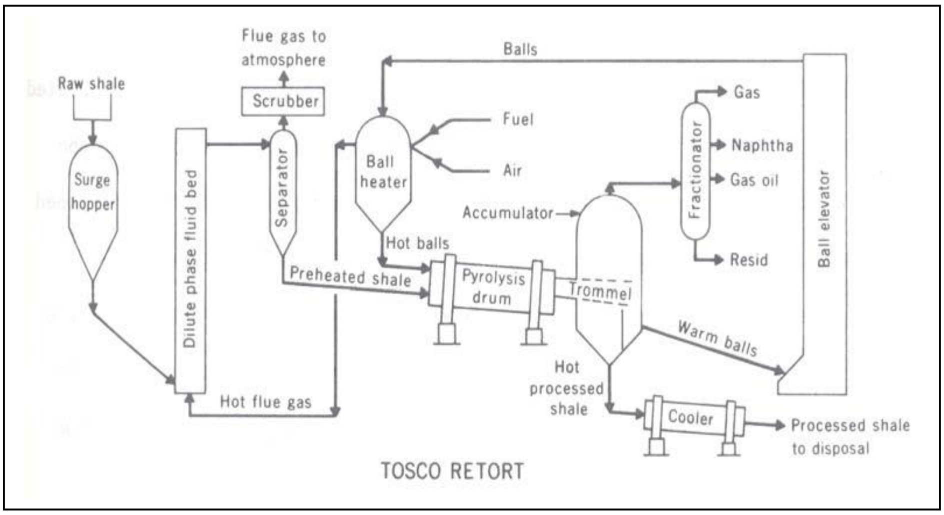

Figure 3.5 The Tosco process [31]

3.2.4 The Kentort II process

This process was developed by the Centre for Applied Energy Research based in the University of Kentucky [30]. It is a multiple stage fluidised bed process. The shale from pyrolysis zone goes to the combustion zone through a downcomer. Spent shale as mentioned earlier contains a significant amount of char that can be gasified at 800°C. The gasification of this char provides the energy for pyrolysis. The vapours contain the gases and oil that are recovered. The pilot plant was a 23 kg/h plant that ran successfully. The project was initiated in 1986. In spite of its technical feasibility, the Kentort II has not been commercialised.

3.2.5 The Lurgi-Ruhrgas Process

The hydrocarbons are released from oil shale by bringing it in contact with hot fines, generally spent shale. One of the conditions for this process is that the shale should not be too rich as it could degrade to a fine powder; in such a case, sand would have to be added as a heat carrier [19]. It should be borne in mind that the Lurgi-Ruhrgas process was initially developed for high ash coals. This process is a fairly complex process with a number of unit operations.

3.3 Heat transfer by other means

Heat transfer by other means implies transfer by conduction, microwaves or radio frequency heating. In any case heat needs to be added to the shale to release the kerogen.

3.3.1 Global Resource Corporation

Global Resource Corporation's technology uses microwave heating to extract oil from oil shale. A press release on their website (http://www.globalresource.com) states that the commercial testing of their technology was successfully completed in October

2008. Not much else is available from their website about the process. It is speculated that shale of a certain size would enter a vessel that would then be subject to microwave heating. The vapours would most probably be processed in a manner similar to other heat addition processes. As the patent is pending, there is little information available in the public domain.

Interestingly in 1995, work was conducted on microwave heating of Australian shales [5]. An advantage of microwave retorting was the recovery of more light ends with less sulphur and nitrogen reporting to the oil. The tests were carried out on a sample with particle size between 3 and 6 mm.

3.3.2 The Oil Tech Process

The oil tech process is now called the Millenium retort after Ambre Energy (www.ambreenergy.com) acquired Oil Tech. The retort consists of a series of heating modules with each module consisting of a series of electrically heated rods that go into the middle of the retort. As the shale moves down the retort it gets progressively hotter where towards the bottom of the retort it attains a temperature close to 600^{o}C. The spent shale heats the incoming shale.

There is not much information available on this process, but it appears that this has not been pursued lately.

3.4 Alternative Processes

While heating the shale is the most common and obvious method of releasing hydrocarbons from oil shale, extraction and direct liquefaction are two additional processes into which significant research is being carried out. In this context it is worth mentioning the Chattanooga Process and Blue Ensign's Rendall Process.

3.4.1 The Chattanooga Process

The Chattanooga process uses pure hydrogen in its process, as a heat transfer medium and as a means to upgrade the oil within the process. A schematic diagram of the process flow is shown below. At the heart of it is a pressurised fluidised bed reactor. The process is self sustaining in terms of energy. It claims to use less water and have less impact on the environment. The process has achieved nearly twice the MFA oil in several pilot trials. This is an interesting process, but has yet to be demonstrated at a large scale.

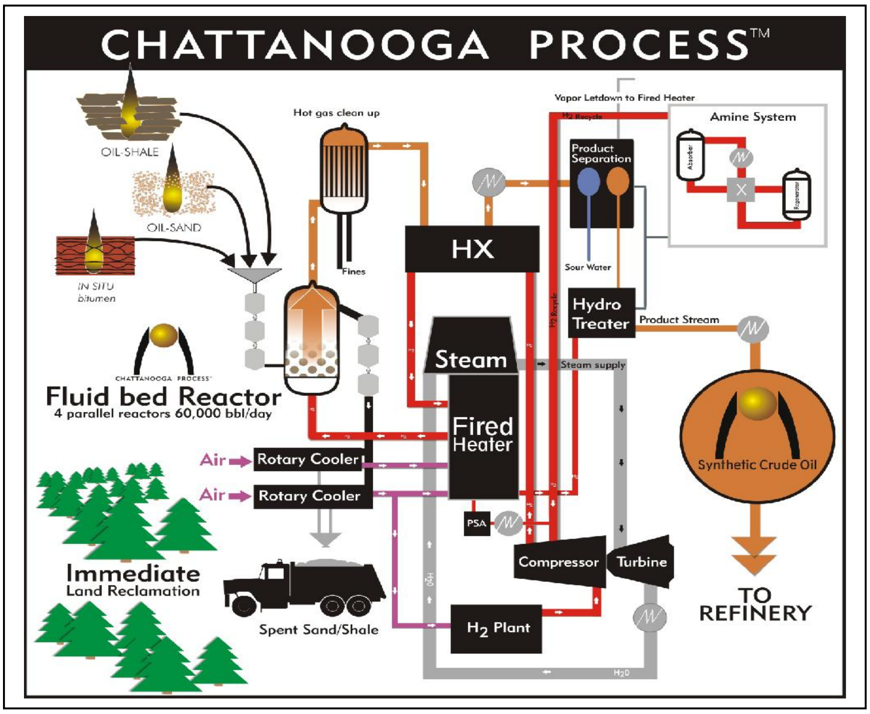

Figure 3.6 The Chattanooga Process (source: http://www.chattanoogaprocess.com)

3.4.2 The Rendall Process

The Rendall Process has been adopted by Blue Ensign Technologies [3] as technology of choice. This process is a supercritical fluid extraction technology where a hydrocarbon fluid is mixed with hydrogen at high pressure and temperature. The resulting extractant is distilled to recover the solvent and product is oil. The offgas from the distillation and the gases from the kerogen conversion and hydrogenation are sent to acid gas removal process and the clean gas is sent to a hydrogen reformer as fuel and feed. Part of the fuel gas is used internally for power generation. It is claimed that the spent shale can be sent through a mineral recovery process and the final residue can be used in making cement. The yields are claimed to be 150 to 300% of MFA and the product oil has a specific gravity between 35 and 40 API.

On paper this appears to be an excellent process and a high level desktop study was performed on this by Shedden-Uhde that states that the process is probable. This process has not been demonstrated.

4. Technology Comparison

4.1 General

A heightened awareness worldwide of the potential of oil shale. Depending on the statistic that is reported there are at least 3-4 trillion barrels of recoverable oil worldwide. For a world that is yet to have an alternative to an oil based economy, shale oil provides an opportunity for new technologies to evolve over a transition period. Australia is particularly vulnerable as it is dependent on transport fuels and currently there is a shortage of about 300,000 barrels per day between production and consumption. The price of oil has started moving up again and the concept of peak oil is being revisited.

It is interesting to note that shale has excited researchers for nearly 100 years. There is a wealth of literature available on shale types, shale pyrolysis and shale geochemistry in general. World leaders include Lawrence Livermore National Laboratories (LLNL) in Berkley California. The study of Australian Shales has been pioneered by SPP/CPM through CSIRO energy group. Owing to the commercial-in-confidence nature of these studies much of this information is not publicly available. Kinetic studies have also been conducted by LLNL who have also developed a detailed and complex first-principles mathematical model of the process. The Tasmanian Government has also conducted a number of studies into oil shale that include characterisation, geo and chemical characterisation. Information has been recorded in a number Tasmanian Government reports.

Boss Energy has a fairly rich oil shale resource in Tasmania that could be monetised through the application of a suitable technology. Thus the main considerations in this comparison are

- Technology Status and Scheduled Operation
- Environmental Effects
- Engineering Risks (high level)
- Technology Development Plans
- Economics
- Barrier Issues

Table 4.1is a summary of information for those processes where data was available. It lists the key processes previously discussed (section 3). Environmental information regarding the processes is not readily available in the open literature, but a considered opinion regarding environmental issues is provided.

Four processes worldwide that have been in commercial operation for any length of time, namely

» Kiviter

» TSK

» Petrosix

» Fushun

The two operations in Estonia, the Kiviter (lump process) and TSK (fines) have been performing for about 70 years. The Petrosix process has evolved over 50 years to the two retorts, a larger 260 tph facility and a smaller demonstration facility of 65 tph. The Fushun retorts again have been operating for over 60 years and have evolved into strong performing units in recent years.

Other notables are the Paraho process which is really the direct descendant of the Petrosix process. The intention was to utilise the char to provide the heat of retorting, all within the same retort. It worked particularly well for Colorado/Utah shales achieving greater than 90% yield. A 10 tph semi-works plant was built in Colorado in 1972, but as oil prices dropped the entire facility was demolished. Currently Queensland Energy Resources in Australia is developing with the Paraho Process for shale to liquid.

The Alberta Taciuk Processor has also had an interesting past. In spite of public perception, the 250 tph processor of the erstwhile SPP/CPM project was technically successful. It is true that there were some issues, and it is speculated that these may have been due to ancillaries. What makes the ATP worthy of consideration in spite of the negative public perception in Australia, globally there is still some interest in this process. Fushun is currently building an ATP plant and the Jordanians are considering the ATP process for one of their deposits. This suggests that it may be too early to write off ATP.

The TOSCO process was perhaps one of those processes that was fully designed and costed [19] for commercial operation but never built. There has not been much information since the TOSCO chapter was closed. GHD has limited the study scope by eliminating unproven technologies or those that are still in bench scale and have little commercial basis. GHD has imposed this scope limitation.

In spite of numerous surface or ex-situ processes for shale to oil, there are only a few that have stood the test of time.

Table 4.1 Summary of major processes (internal GHD report)

Name of process	Type	Shale Type	Distinguishing features of shale	Similarity to Tasmanite	Location	Lab/Bench	Pilot	Demo	Commercial	Throughput tonnes/hour	Oil Yield % MFA
Paraho	Ex-Situ lump Vertical Retort Combustion heat or gas heating Direct/Indirect	Colorado Australian (Stuart Deposit, McFarlane Deposit)	low moisture content 1% to very high moisture 15%, 65 - 140 LT0M	2	Colorado	Y	Y	Y	N	10	85-90
PetroSIX	Ex-Situ lump Vertical Retort Indirect Gas heating	Irati Green River	~102 LT0M 3.1% free moist 0.3% bound moist	3	Sao Mateus, Brazil (original) Techno/economic/environmental studies have started on White river shale for OSEC - oil shale exploration company R&D		Y	Y	Y	260	75
Fushun	Ex-Situ lump Combustion (Direct) heating	Fushun	~97 LT0M free moist 11.3% wet bound moist 3.8%	6	Fushun			Y	Y	4.2-8.3	75
TOSCO	Ex-Situ Fines Rotating Kiln Solids heat transfer	Colorado Shale	low moisture not more than 1-2% tot ~150 LT0M	6	Colony project, Colorado		Y 24 t/d	Y	Y (end 1972)	40	75

Name of process	Type	Shale Type	Distinguishing features of shale	Similarity to Tasmanite	Location	Lab/Bench	Pilot	Demo	Commercial	Throughput tonnes/hour	Oil Yield % MFA
Kiviter	Ex-Situ lump Vertical Retort Combustion heating	Kukersite	high moisture 5.8% fm, 2.5 bm ~300 LT0M	10	VKG			Y	Y	40 (multiple retorts)	75
TSK	Ex-Situ Fines Rotating Kiln Solids heat transfer	Kukersite	as above	10	Eesti Energia plant in Narva			Y	Y	2*125	85-90
ATP (AOSTRA/Alberta Taciuk Process)	Ex-Situ Fines Rotating Kiln	Tar Sands Stuart Oil Shale Fushun Oil Shale	large variability		Alberta Gladstone (was) Fushun			Y	Y	250	85-90
Chattanooga	Ex-situ Fluidised bed H2 is HT medium 600 psig; 1000F	Variety of feedstocks includes heavy oils	not provided low moisture suspected	5	Guess Chattanooga		Y	Y Plans to design /engineer and cost 60,000 bbl/d			95
Millenium Synfuels and Ambre Energy (Aus) Oil tech vertical retort technology	Ex-situ Lump Retort External heat conduction	Variety of feedstocks including coal, shale	Typical Utah shales with 30-60 GPT(American units)	4	Utah		Y	N	N	~350 tph proposed in 2008, revised date in summer 2009	

Name of process	Type	Shale Type	Distinguishing features of shale	Similarity to Tasmanite	Location	Lab/Bench	Pilot	Demo	Commercial	Throughput tonnes/hour	Oil Yield % MFA
Global Resource Corporation	Ex-Situ Lump (<3") Microwave heating Vacuum	Variety of feestocks including tyres and oil shale	Based in US and would most probably be Utah/Colorado shale	5	Rockford Illinois		Y	Y studies performed	N Commercial studies being undertaken	10 planned demo	

5. Other Factors

5.1 Water Considerations

The amount of water required for above ground retorting (AGR) ranges between 2.3 and 2.7 barrels of water per barrel of shale oil [33]. Water utilisation per operation (*ibid*) is 42.65% for direct AGR and 37.89% for indirect AGR; Power Generation, 5.19% and 9.89% direct and indirect respectively; Disposal and Reclamation, 25.93 % and 36.87 % direct and indirect respectively; and Mine Ore and Handling, 15.17 % and 9.36 % direct and indirect respectively. As only above ground processes are considered, this would be the expectation for the processing of tasmanite. Depending on the wetness of shale is there is some possibility of recovering low grade water in quantity from stripping of sour water. This low grade water can be used for cooling the spent shale and disposal.

5.2 Energy Considerations

There is much hype about energy utilisation in the production of oil from shale. Indeed that processes of mining, crushing, drying, retorting, recovery, treatment and upgrade have energy requirements that quickly add up. Depending on the process there is a great variation in energy recovered to energy invested. This ratio could vary between 0.7 and 13.3 (unreliable reference) and between about 3.5 and 5, which may be more realistic. Thus contrary to perception, the shale to oil process is energy positive. A business case cannot exist if the ratio were to drop below 2. Specific information about each process is unfortunately not published. A recent work by Brandt [5] has compared the ATP with Shell in-situ. For the ATP at the low energy level a ratio of 2.5 to 1 was reported but much lower for the Shell in-situ process.

5.3 Cost Considerations

The major cost of shale to liquid plant lies in its ancillary infrastructure. Cost per barrel/day for commercial facilities could be of the order of US$ 60,000 per barrel per day. As there are no recent constructed and reported commercial facilities costs figures are hard to come by. It would not be unrealistic to assume a cost of a facility in the vicinity of US $150,000 (+/-30%) per barrel per day based on escalation of reported costs for projects completed in the past. Labour, transportation, insurance, and material costs have increased significantly peaking in mid 2008. A Front End Engineering and Design (FEED) would be able to give a tighter estimate. The economic downturn of 2009 may suggest lower costs if built today. Table 5.1 below is a summary of CAPEX for various plants. The $1.6 million/barrel/day of oil for the Stuart ATP Pilot plant is to be expected owing to the scale; a pilot plant will have similar design costs, the only major reduction is the material used. Furthermore, a pilot facility is expected to be much more flexible. This is not representative of a true commercial facility. Much of the information is dated; however it forms a good basis for a forward decision making.

Table 5.1 CAPEX of plants (source: internal GHD report)

Process	Oil Produced bbl/d	Total Cost US$M (1997)	Unit cost $/(bbl/d)
Colony Project Tosco II (1980)	43,000	2,694	62,651
Union Oil Company (1982)	10,000	954	95,400
Julia Creek Tosco II (1983)	100,000	6,900	69,000
Rundle II (1983)	17,000	987	58,059
	75,000	4,060	54,133
Condor Lurgi LR (1983)	82,100	3,519	42,862
Stuart Lurgi LR (1985	8,950	326	36,425
Stuart ATP (1987)	4,250	167	39,294
	14,200	323	22,746
	60,000	1,368	22,800
Stuart (ATP Pilot) (1977-'96)	75	120	1,600,000
Stuart Demo (1996)	4,500	200	44,444
Stuart Commercial Module (1996)	14,800	360	24,324
Stuart Commercial (1996)	65,000	1,597	24,569

Ex-situ processing of oil shale involves a number of processes starting from mining and crushing to producing the final products of oil and gas. The main components of the operation include mining, extraction and upgrading. The upgrading of raw shale oil is equivalent to a mini refining operation and hence the costs. Table 5.2 below presents a breakdown of these costs.

Table 5.2 OPEX of plants

Process	Colony Project Tosco II 43,000 bbl/d US$ (1980)	Julia Creek Qld, Australia 250,000 bbl/d US$ (1980)	Rundle Qld, Australia 250,000 bbl/d US$ (1980)	Alberta Oil Sands (Suncor) ATP Process 94,000 bbl/d $A (1998)	Stuart, Qld ATP 4,500 bbl/d $A (1996)	Stuart, Qld ATP 14,800 bbl/d $A (1996)	Stuart, Qld ATP 65,000 bbl/d $A (1996)
Mining, Crushing and Shale Disposal	3.15	5.94	3.09	7.8		5.2	3.9
Extraction	3.38	6.65	2.91	3.9		5.2	3.9
Upgrading	1.51	2.58	5	7.8		5.6	4.2
Total OPEX ($ as is)	8.04	15.17	11	19.5	21	16	12
Total OPEX (1997 US$)	14.86	28.05	20.35	13.75	16.44	12.53	9.5

Table 5.3 below shows the percentage costs per operating unit. The percentage of split cost is a reflection of how important each operation is to the entire operation. The extraction would also include the oil recovery and treatment of wastes.

Table 5.3 OPEX cost split

Process	Opex Cost Split	Opex Cost Split (ref 2)

Mining, Crushing and Shale Disposal	35%	40%
Extraction	33%	40%
Upgrading	32%	20%

Table 5.4 reports the surface retorting costs from another study. The escalation (inflation) factors are from the US Federal Reserve. These costs should be treated with caution as the cost of a plant today would include the increased costs of services etc. in addition to inflation.

Table 5.4 Surface retorting costs

Surface Retorting costs				Tot Eq. Cost (US$/bbl)			
Type	**Size bbl/d**	**Capex US$ M**	**Opex US$ M/a**	**10% return**	**15% return**	**Published date**	**2009 $ Esc Factor**
Tosco	55,000	510	43	7.6	11.8	1978	3.35
Union	10,000	92		8	12.5	1978	3.35
Lurgi	50,000	30		5.2	12.5	1976	3.84
Paraho	100,000	700	81	5.3	7.9	1977	3.60

The foregoing has presented an indication of costs of some processes

The UNOCAL plant was US$ 650 million in 1985 and ran until 1990 (http://ludb.clui.org/ex/i/CO3191/). A 5500 barrel/day plant has been approved to be built in Estonia and should be ready by 2011. This facility is expected to cost 192 million Euros (about US$ 270 million). This gives a cost per barrel/day of US$ 49,000 which is similar to reported figures above (www.energia.ee). The process is the TSK process that is enhanced by their engineering partner Outotec.

The discussion on cost is to provide a background on possible costs and identification of cost centres within the Shale to Liquid Process.

5.4 Initial Screening

Processes will be considered for further evaluation on the basis of:

- Commercial or compelling commercial example
- Length of operation
- Commercial opportunity

Each of the processes listed below meet the criteria listed above.

- Paraho
- TSK
- ATP
- Petrosix
- Kiviter
- Fushun

Process features are summarised below before going into the detailed analysis.

Paraho

This process has been demonstrated in the US at pilot and semi-works level. Currently Queensland Energy Resources is developing this technology. Considering timelines (about 5-10 years) for oil shale commercialisation in Australia, there is potential for this technology to be conclusively proven on Australian Shales. Links between QER and Boss Energy are being established and therefore this technology cannot be ruled out.

TSK Process

This process has been operating for over 50 years and there are plans to construct a new 5500 b/d facility by 2011. Eesti Energia, the owners of this process claim to ensure better environmental controls with their new process to meet European requirements; also claimed are improved yields of 103% of MFA. This capacity appears to be an ideal size (please see Section 40). This process is also being considered by the Jordanian Government.

Alberta Taciuk Process

This technology was first demonstrated at the Stuart Plant in Gladstone operated by SPP/CPM and for a short while by QER. The ATP process received much bad publicity through Greenpeace. The ATP process plant had a capacity of 250 tph (6000 t/d), a capacity that is manageable and economically viable. Furthermore, Fushun Mining Group, the owners of the Fushun retorts are currently completing the construction of an ATP plant to process their shale. The Jordanian Government is also considering this technology for one of their deposits.

Petrosix

This technology has a history that spans nearly 40 years and has evolved in the current technology. It processes about 260 tph in a vertical retort and the shale is heated indirectly. There is very little information in the public domain regarding this process, but it has been operating for a long time commercially. They only consider Joint Ventures and do not license their technology. They recently signed up with Mitsui and OSEC to study the suitability of Utah shales. Petrosix has not advanced beyond the 260 tph perhaps a mechanical limitation imposed by their retort. Petrobras the owners claim to have addressed environmental concerns.

The Kiviter Process

The Kiviter process has been in operation for about 70 years and during this time has evolved into what it is today. It has a documented history. Kukersite and Tasmanite are similar and this makes Estonian processes worth considering.

The Fushun Process

Again this process has been around for a long time and has been tested with different shales. It has been operating commercially for several years now. Currently 140 retorts are operating. Jordanian oil shale has been tested on the Fushun retorts successfully with fairly high recoveries.

In order to determine the most relevant technologies for Boss Energy, the following evaluation criteria were chosen.

» Technology Status and Scheduled Operation
» Environmental Effects
» Engineering Risks (high level)
» Technology Development Plans
» Economic Analysis
» Barrier Issues

These criteria have been adapted from the *California Energy Commission guide to technology assessment and project development*.

5.5 Technology Status and Scheduled Operation

Table 5.5 Status and Evaluation

Process	Evaluation
Paraho	Currently this technology is being redeveloped by Queensland Energy Resources in Australia. It was proven in the past for Colorado and Utah Shale. Potential demonstration 2012 (speculative based on their website) Score: 3.5/5
TSK	Well tested technology and commercially operating plant. New plant expected in 2011. Currently have 2*125 tph plants. Constructing a new plant with improved energy efficiency. Score: 4.5/5
ATP	Proven from a technology demonstration perspective at the Stuart Shale Project. Fushun Mining Group currently building an ATP processor of capacity 230 tph. Score: 3/5
Petrosix	Oil Shale Exploration Company has signed an agreement with Petrosix for a JV plant in Utah. Petrosix has a retort operating over several years of capacity 260 tph. Score: 4/5
Fushun	This process has evolved over 70 years and is also being evaluated by the Jordanians. About 140 retorts in operation, each of 100 t/d capacity. Well tested. Limited information available. 4/5

Process	Evaluation
Kiviter	Well established process that processes kukersite, a shale similar to tasmanite. Lower yields and plant availability is not high. 3/5

In terms of technology status the frontrunners are TSK, Petrosix, Fushun followed by Paraho and then the rest. Considering the timelines of operation, it may be possible to leverage off QER should the Paraho technology be conclusively proven.

The inclusion of ATP has been driven by the recent commercial ventures [16]. Again this is a technology that has to be monitored as it has the potential to succeed.

Capital costs would be of the order of US$ 50,000 to US$70,000 per barrel/day.

5.6 Environmental Effects

The two key challenges are the environment and safety. To quote a former colleague “the shale process is like a balloon, press one end we have a problem at the other”. The composition of shale is a defining issue. If it has too much of moisture, then perhaps drying is an option that implies greenhouse gases as energy is required for drying, and/or water treatment costs. There is a requirement to treat the water and gas; preparing the oil for upgrading; safe disposal of spent shale. The other challenge is dust. Dust suppression is a significant consumer of water. Odour is not necessarily a pollutant but the perception of a bad smell implying something very bad is hard to change.

The environmental effects are expanded below.

5.6.1 Greenhouse gases and Sulphur

The Shale to Liquid process consumes a lot of energy roughly a third across mining, processing and upgrading as was discussed in Section 4.1. The main contributors to CO_2 are the heat required for drying, heat for processing, energy for operation and energy for upgrading. The other gaseous pollutant could be sulphur but with established technology for sulphur recovery may not pose much of a problem. Dioxins are generally nonexistent (well within the most stringent standards). There could be some NO_x associated with burning though. Carbon capture would have to be actively considered in light of the proposed Carbon Pollution Reduction Scheme (CPRS).

5.6.2 Water

The sour water that leaves the retort contains ammonia, sulphur dioxide, hydrogen sulphide, organic and inorganic components. It is possible to use traditional sour water treatment technology to remove ammonia and hydrogen sulphide; however removal of all the organics from water is not entirely possible. Fortunately, the spent shale (char) is somewhat activated. This suggests that water after traditional sour water treatment could be safely disposed off onto the spent shale. As mentioned earlier, the composition of the water will depend entirely on the shale and to a lesser extent the method of processing.

5.6.3 Spent shale

When shale is mined and retorted the volume increases nearly 1.2 times. This is not due to what some authors state as the popcorn effect, rather it is the creation of more surface area that is the main contributor to this increase in volume (new voids). There are concerns that heavy metals and other organics could leach out of the spent shale. However, this would need to be tested and evaluated. There is a high probability that the stripped sour water could be safely co disposed with the spent shale. The pictures below show that spent shale can create interesting landscapes and with care can lead to benign ecosystems. Research from Estonia suggests a three year period over which the alkaline ash was enriched with urea before nature has reclaimed the land. The photographs below illustrate this.

Figure 5.1 Ash heap and revegetated ash heap (http://www.bspinfo.lt/bspnews/992/992_33.htm)

Table 5.6 Environmental Evaluation

Process	Evaluation
Paraho	In Direct Mode spent shale is mostly ash. Disposal with stripped sour water. Depending on mining method and location of processing plant, the spent shale could be located elsewhere. Over a period of time this could be a large footprint. In Indirect Mode, spent shale would have larger quantity of activated carbon. Wet shale implies large amounts of sour water to be treated. Easy to separate ammonia and sulphur, but organics to be bound by char needs to be evaluated separately Large gas flows for heating imply large heat input. This could increase GHG. Carbon capture would be strongly recommended. Upgrading could be expensive. Depending on shale type issues with catalyst poisoning. Fairly Safe. Shutdown is as simple as turning off a switch. No power, no process and heat is retained for a sufficient time (at least 6 hours if not

Process	Evaluation
	longer). Score: 3/5 for environment Score: 4/5 for safety
TSK	Well tested technology and commercially operating plant. New plant expected in 2011. Spent shale is mainly ash. Disposal in pits with stripped sour water. Needs to be regularly monitored. As fines processor concern with fines and ash handling. Oil is partially stabilised in the process itself. It uses less water and the drying zone is separated from the processing zone. This reduces load on water treatment. Most of the heat is generated by the process itself. Carbon capture is still important as the flue gases from char combustion would contain carbon dioxide. There are some issues with emissions and heat integration. Retorting compartment is separate and can be isolated from the rest of the process. Thus it is safer than the ATP process. Score: 3/5 for environment Score: 3.5/5 for safety
ATP	Being a fines processor there is the issue of dust and dust suppression. Heat is produced by burning the spent shale in the rotating multi-compartment kiln. There is a limited upgrading of the oil within the retort. From reports, there were no environmental issues other than odour. The odour was not an environmental hazard. Spent shale and stripped sour water were safely co disposed. From a safety point of view, there are a few more issues. While the process design is excellent, the mechanical aspects were challenging. The multi-compartment kiln had different temperature zones, the combustion zone where temperatures could reach 1000^{o}C to the preheat and drying zones where the temperatures would range from ambient to 150^{o}C. Thus an emergency shutdown was always a difficult condition as not only had the hot shale to be removed out of the kiln safely, but the temperatures in the zones were not to exceed limits. The kiln had to keep rotating in order to prevent sagging. Score: 3/5 for environment Score: 2/5 for safety
Petrosix	There is no much information available about the environmental impact other than their website that claims that environmental issues are addressed. Considering that Petrosix is the forerunner to Paraho, it most

Process	Evaluation
	probably would suffer the same issues. The Petrosix process appears to carry a higher recirculating load of water and this might reduce the sour water treatment load. However, they use a water seal at the bottom of the retort that implies large water use. The ash and water are co disposed. To the best of our knowledge there are no adverse environmental reports in then public domain. In an emergency, similar to the Paraho process, it is as simple as removing the heat source. Score: 3/5 for environment (not all information is known) Score: 4/5 for safety
Fushun	This is a retorting process similar to Paraho. It is not clear how the Chinese manage their waste streams. It is clear though that they are moving from a period of relative less regulation to greater regulation. 20 retorts are linked to one oil recovery and this makes it easy for shut down and maintenance. It would have similar safety features to other vertical retorts. It uses a water seal as well and co disposes spent shale and water. Carbon capture would be required Score: no score for environment (no information available) Score: 4/5 for safety (similar to Paraho)
Kiviter	The Kiviter Process is also a well established process that processes Kukersite, a shale very similar to tasmanite. This process has a low availability. Reports that available in the public domain suggest that that the environmental impact of the process have been high. Rather than indict the process, it is a recognition of the economics of clean up versus the need of the country. With EU membership, these limits are being revisited as environmental impact is now important. Score: 3/5 for environment Score: 4/5 for safety

From an environmental perspective all processes are at a similar technological level. What is important to note though is that the *composition of shale* is a critical factor. More water implies drying/increased sour water treatment; energy utilisation translates to a carbon footprint and greater degree of mitigation; solids processing implies dust and its suppression.

Eesti Energia is constructing an enhanced TSK process with reduced emissions; Petrosix is still operating and has evinced interest from other international players; ATP has had a new lease on life; and closer to home Paraho is being developed in Queensland.

Based on the information in the public domain, **TSK, Petrosix and Paraho** appear to have least impact on the environment.

5.7 Engineering Risks (high level)

The engineering risks associated any project are political, financial, technical and economic.

5.7.1 Political risks

From discussions with Boss Energy, it is clear that there is confidence in the Tasmanian Government and there is possibility for some support from them. The Tasmanian Government intends to develop its resources. The proximity of the resource to an industrialised part of Tasmania (cement works is the major industry) and a major port (Devonport) may imply less political and public opposition to such a project.

The potential technology providers are from countries that have been fairly stable and have good relationships with Australia. No risk is foreseen any risk in this regard.

At a high level there is somewhat less political risk than in other states such as Queensland.

5.7.2 Financial and Economic Risks

The ability to raise finance is beyond the scope of this report. However, the economic situation is related to the price per barrel of oil in addition to market stability. With peak oil discussed at length by various authors, a reasonable price of oil representing demand and economic growth is critical. A sustained price of about US $65 - $75 per barrel appears to be a threshold range beyond which such projects become economically viable. It is beyond the scope of this document to provide professional advice on financial and economic risk.

5.7.3 Technical Risk

The processes being considered have all been in operation for a length of time and are still being evaluated (in the case of Paraho). The process plants have been in operation for some time and been proven over a number of years. The oil from these processes has also been tested on various end users (aircraft, vehicles, generation etc.). Thus there is a low technical risk.

However, as discussed earlier process behaviour is dependent on shale type. Even if the technical risks are low, the greatest risk remains the characteristics of shale and how that shale would perform in the retort. Therefore technical risk can only be evaluated and mitigated through testing shale in the process.

Although most major technologies are being showcased in Jordan, the TSK process appears to be the most promising. It not only has been in operation for over 50 years, but also processes Kukersite which is similar to Tasmanite. The TSK process is also being enhanced with a low emission and improved plant.

Based on the foregoing, TSK is the frontrunner followed by Petrosix, Paraho and Fushun.

5.8 Technology Development Plans

The TSK process in Estonia as discussed earlier is enhancing its process that would lead to reduced carbon dioxide emissions. This plant is expected to be ready by 2010. Petrosix is working with OSEC in Utah to test Utah shale. Jordan has invited all major players including ATP to build demonstration plants. Fushun is building an ATP plant. Here in Australia, Queensland Energy Resources is developing the Paraho II technology (www.qer.com.au).

Thus all technologies are being developed and this shows the recognition by the industry that oil shale is important resource. In countries such as Estonia and Jordan where there are hardly any resources of oil, oil shale has been and continues to be exploited. What is particularly noteworthy is the transparency of the Estonian Oil Shale Industry and their willingness to improve and change. Of course part of the need for change is their requirement to clean their environment to meet European Union acceptance. The new facility at Narva (TSK) is being developed for this reason. There is recognition of environmental impact and action is being taken to address this.

Technology development is an important area of focus for all technology providers and suppliers. It would be hard to rank one above the other.

5.9 Barriers to Oil Shale

Scientific **uncertainties** and knowledge gaps in each of the identified processes is low as each process has undergone significant testing and data collection. The only uncertainty would be the performance of the process with tasmanite.

Engineering and materials barriers would be associated with the ancillaries rather than the actual processor. Appropriate engineering solutions would be required for water treatment and gas clean-up. However, these are surmountable barriers as some of the more established processes have been battling similar problems.

Environmental issues have been discussed in Section 5.6. The environment is becoming increasingly important and environmental impact will be under close scrutiny. This barrier is to be viewed as an opportunity rather than an impediment. Estonia has taken this view and is working towards cleaning up its environment. While the SPP/CPM plant met the environmental conditions, the public perception went against them. Thus the greater risk is the perception of the public who are not familiar with oil shale and the extraction process. Education would be an important part of any project.

Resource Constraints are not an issue. Boss Energy has rights to 42 million tonnes of shale at low depth and about 30 million tonnes at depth. The resource grade has a median of 130 litres per tonne of shale at zero moisture. This translates to a potentially recoverable resource of at least greater than 23 million barrels. The shale is easily mined (information from Boss Energy) and mine rehabilitation is straightforward.

Institutional and Regulatory barriers are really check posts for the project to proceed. It appears that the Tasmanian Government has less stringent regulatory barriers to such projects. The important hurdle would be Environmental Approval for the project. Noting that the Stuart Shale Project did not exceed any environmental limits for a 250 tph operation, there is every expectation that even at a more realistic 4 – 5,000 bbl/d facility the overall environmental emissions would be within the stringent Queensland standards.

5.10 Shortlisted Shale to Oil Processes

Various technologies were discussed in the previous sections. The Environment and Commercial viability have been the drivers in concluding that the processes that merit further evaluation are TSK, Petrosix and Paraho.

A single factor in itself is not conclusive. There is also some subjectiveness in this selection as it is felt that there may be a possible synergy with QER.

The shortlisted processes are not intended to preclude other opportunities. Detailed technology evaluation could take a couple of years and the development of a resource to Commercialisation could take 5-10 years. It is acknowledged that a number of technologies are being developed elsewhere and there is the possibility that a particular process may prove superior to those shortlisted. To ensure the best possible outcome for Boss Energy commercial and technology continues.

6. Development Alternatives

6.1 Tasmanian Shale to liquid facility

The capacity of a shale to liquid facility should be set at a size where economies of scale and a rate of return of at least 8% could be achieved. The total Tasmanite resource (shallow and deep) is about 72 million tonnes of shale which is equivalent to about 54 million barrels of oil.

Assuming a recovery of 70% and a plant life of 25 years would suggest a plant size about 4,500 barrels/day (~250 tph of raw shale). Plant capacity of the TSK plant being built in Estonia is a 5,500 barrels/day facility with a reported cost of US$ 270 million.

The choice of 4,500 barrels per day is based on 75% recovery of oil from the total resource of shale. Similar sized plants have been built in the past and are currently being built.

The footprint of such a plant would not exceed about 10 hectares. The mining requirement would be about 6 - 7000 tonnes per day.

Using an oil price of about US$ 80 and assuming a worst case scenario of US$ 60/bbl/day of operating cost with a rate of return of 8%, the NPV over 25 years is just over US $54 million.

The above is only indicative. The construction of a plant involves a lengthy approval process that would cover critical issues such as environmental impact. There are social implications and synergies with other industries that would also need to be considered.

6.2 Offsite/Toll Processing

Processing the shale offsite is another option. It is possible to consider a monthly consignment of shale, however most small plants would require about 5,000 to 6,000 tonnes of shale for about 4 to 5,000 barrels of oil per day. The load of shale equates to between 23,000 and 38,000 barrels of recoverable oil. Assuming 80% recovery and a rate of US$ 80/bbl, this works out to expected revenue of US$ 48 per tonne of wet shale. We are not sure at what price a prospective processor may be willing to pay for shale, but a price of US$ 15 per tonne is realistic. The shale may have to be prepared to specifications.

An alternative method of determining the approximate prices that could be charged for a tonne of shale is based on the coal price equivalent. Xstrata signed a deal with the Japanese where it locked the price of thermal coal at US$ 80 per tonne (The Australian, Dec 19 2008). Thermal coal typically has a heating value of 27 GJ per tonne. Kukersite which is similar to Tasmanite has a heating value between 5 and 8 GJ a tonne. This implies that for every tonne of coal about 4.2 tonnes of shale would have to be shipped to recover the same energy value. Based on this a price per tonne would be about US$ 19.3. This would not include pre-processing of the shale. Associated with increased mining requirement are increased costs and increased shipping charges.

Eneabba Coal is at a similar depth to tasmanite and a study was carried out by Sleeman Consulting in associating with GBRM on Energy for Minerals Development in the South West Coast Region of WA. Table 6.1below has been reproduced from their study report [24]. This information is based on an overburden ratio of 7:1.

Table 6.1 Cost component per tonne of Coal

Cost component	A$/t	US$/t
Pre-strip and rehabilitation	0.5	0.4
Overburden Removal	10.5	8.4
Coal recovery	1.5	1.2
Coal crushing	0.8	0.64
Coal washing	1	0.8
Conveying and miscellaneous	0.75	0.6
Owner's costs and notional margin	5.75	4.6
Royalty	2.3	1.84
Total cost including margin	23.1	18.48

Eneabba coal has a heating value in the range of 15-17 GJ a tonne. When compared to tasmanite, it suggests a 2.5 to 3 times the quantity to be mined to meet the same energy value.

It is quite possible that similar costs may be applicable to Boss Energy's deposit. The advantage that Boss Energy would have is the proximity of its resource to a well established port.

It is not the purpose of the foregoing discussion to force a conclusion. Rather, it provides a baseline reference to what is believed to be a similar resource. The use of shale and the end use of the ash are important factors that need to be considered.

It is thus possible to consider mining and shipping the shale to users elsewhere. Although a low grade fuel, shale as a coal substitute may be attractive to energy poor countries and cheaper too.

6.3 Synergistic Applications

Power generation has been a major use of oil shale in Estonia. In Australia coal and natural gas are the preferred alternatives. Tasmania is blessed with different sources for power – renewable energy (including hydroelectricity), natural gas and coal. Shale is a low grade fuel with a heating value of only 5-8 GJ/tonne.

Peak natural gas similar to peak oil is predicted, and as more energy is demanded, the fear of running out is more real.

It may be possible to combust shale for power generation to be used in a local plant in the same area; the waste shale may have a use in the cement industry.

6.4 Alternative Solutions

Owing to the shale's similarity with coal it may be possible to gasify the shale to produce a gas for power or Fischer-Tropsch synthesis. This is only a possibility and would need to be studied separately. Ambre Energy in Felton Queensland is using retorting technology to convert coal to dimethyl ether (DME) and char which is used for power generation. Although a possibility it could be further explored. This has not been progressed at this stage.

A technology provider, in Logan USA, Dr. Brent Fryer has developed technology for retorts up to a capacity of 1000 t/d. He requires shale to a certain particle size specification. He will pay for the retort (called Black Box) and the shale provider would have to worry about the ancillaries including disposal. He charges a fee for the black box and this could be in the form of oil. This is an interesting option, but not much information is available. The lack of information and the onus of shale preparation and downstream processing including upgrading is on the shale supplier. This implies that adopting this process is as good as investing close to 80% of a full plant.

To conclude this section there are several processes to extract oil from shale. Several operators and technologies claim to be innovative and commercially viable, however there is insufficient evidence to prove their credibility. Some technologies has focussed primarily on the process of extraction rather than including all the unit operations that would include mining, preparation, treatment of wastes and safe disposal. A counter to above ground retorting, in-situ processing started with great promise and there are again a large number of variants all focussed on the best way to provide the energy to the rock to retort it. While research is still progressing, it has not been demonstrated at a scale that suggests commercial viability.

7. Summary of Findings

GHD has screened a number of technologies for converting oil shale to liquid oil and has identified processes that have the most potential as at the time of the report. The following evaluation criteria were used to evaluate shale to liquid processes:

- Based on Technology Status and Scheduled Operation
- Environmental Effects
- Engineering Risks (high level)
- Technology Development Plans
- Economics
- Barrier Issues

The shortlisted Shale to Liquid processes based on these criteria were

TSK

Petrosix

Paraho.

Additionally other options were discussed. These options are:

- Offsite Toll Processing
- Synergistic Solutions
- Alternative solutions

Stage 2 of this project is discussed in the next section. It would propose an evaluation of all options that would lead to the selection of a safe, environmentally sound and commercially viable solution to monetisation of Tasmanian Oil Shale.

A key learning from this study is that the shale to liquid/power/other use journey is one that is constantly evolving and improving. There is positive change in the industry where there is active recognition of the principles of environmental protection and sustainability.

There is worldwide interest in oil shale and shale is at the cusp of becoming a major resource in the energy sector as common forms of energy become more expensive and difficult to access.

8. Stage 2 Project Definition

8.1 Options

The initial technology screening study shortlisted technologies that could be suitable for developing Boss Energy's Tasmanite resource. The study also identified alternative options for utilising the resources. The main

Shale to Oil

Offsite/toll processing of shale

Synergistic Applications

Alternative Solutions

8.2 Project Definition

Stakeholder consultation would be conducted at the start to understand the requirements and identify the evaluation criteria for commercialisation.

8.2.1 Option Selection

Detailed information would need to be collected for each of these options. Cost basis and Commercial analysis would be an integral part of this.

Understanding and costing considerations of the approvals process such as environmental impact statements would be considered.

These details are listed below:

» Suitability for Tasmanian Shale Deposit

» Detailed technical comparison (includes a visit to the site for oil technology review)

» Environmental impacts and mitigation strategies

» Mining

» Spent shale handling (for shale to liquid and shale to power)

» Cost/Benefit comparison

8.2.2 Detailed Feasibility Scoping Document

The options select would lead to developing a scoping document that would set the terms of reference for further work and evaluation leading to a final investment decision.

8.2.3 Detailed Feasibility Study

A Detailed Feasibility Study would be conducted for a selected option. Such a study would include details of process information, costs, safety and other factors that would contribute to making a considered Financial Investment Decision. This work would include where relevant:

- Mining impact
- Mine rehabilitation
- Pilot runs with Tasmanian Shale
- Environmental Issues – water, gas and spent shale
- Upstream handling/processing
- Downstream processing – oil recovery, water and gas
- Oil upgrading
- Cost estimation and comparison for options

At the conclusion of Stage 2, Boss Energy would be able to make a Financial Investment Decision.

9. Bibliography

1. Andrews, A.; (2006) Oil Shale: History, Incentives and Policy, "CRS Report for Congress"
2. Bachmann, D. L., Terabe, K., Novicki, R. E. M., Piper, E. M.; (1993) Petrosix- An Update, "Eastern Oil Shale Symposium", Institute for Mining and Minerals Research, University of Kentucky
3. Blue Ensign Technologies Ltd.; (2007) The Rendall Process, "Presentation"
4. Boss Energy; (2009) http://www.bossenergy.com, last accessed June 2009
5. Bradhurst, D. H., Worner, H. K,; (1996) Evaluation of oil produced from the microwave retorting of Australian Shales, "Fuel" vol 75 no. 3 pp 285-288
6. Brandt, A. (accessed Aug 2009), Converting Green River oil shale to liquid fuels with ATP and ICP technologies, ATP and ICP life-cycle analysis, 27th Oil Shale Symposium, Colorado School of mines, October 2007
7. Dyni, J. R. (US Department of the Interior and US Geological Survey); (2006) Geology and Resources of Some World Oil-Shale Deposits, "Scientific Investigations Report 2005-5294"
8. European Academies, Science Advisory Council; (2007) A Study on the EU oil shale industry – viewed in the light of the Estonian experience, "A report by EASAC to the Committee on Industry, Research and Energy of the European Parliament"
9. Everts, D-J.; (2008) Energy Use and CO_2 emissions of bitumen and oil shale based liquid fuel production explorations in TIMER, "PhD Thesis", Utrecht University
10. Han, Z. and Kruge, M. A., Crelling, J. C., Bensley; (1999) Classification of torbanite and cannel coal I. Insights from petrographic analysis of density fractions, "Int. Jl. of Coal Geology", vol 38, pp 181-202
11. Han, Z. and Kruge, M. A.; (1999) Classification of torbanite and cannel coal II. Insights from pyrolysis-GC/MS and multivariate statistical analysis, "Int. Jl. of Coal Geology", vol 38, pp 203-218
12. Hawthorne, S. B., Sievers, R. E.; (1984) Emission of organic air pollutants from shale oil wastewaters, "Envion. Sci. Technol.", vol 18, pp 483-490
13. Holmberg, R.; (2008) Survival of the Unfit, Path Dependence and the Estonian Oil Shale Industry, "PhD Thesis", Linkoping University, Faculty of Arts and Sciences
14. Hutton, A. C., Graham, U. M., Hower, J. C., Rathbone, R. F. and Robl, T., (1996), Petrography of pyrolysis and pyrolysis-steam retorted residues from the alpha torbanite and the alpha cannel coal, Org. Geochem, vol 24, no. 2, pp 219-226
15. Jaber, J. O., Probert, S. D., Williams, P.T.; (1998) Modelling Oil-Shale Integrated Tri-Generator Behaviour: Predicted Performance and Financial Assessment, "Applied Energy", vol 59, no. 2-3, pp 73-95

16. Jaber, J. O., Sladek, T. A., Mernitz, S., Tarawneh, T. M.; (2008), Future Policies and Strategies for Oil Shale Development in Jordan, “Jordan Jl of Mech and Ind. Engineering”, vol 2, no. 1, pp 31-44

17. Kane, R. F.; (1968) The constitution of Tasmanite, “Joint Symposium on Oil Shale, Tar Sands, and related Material Presented before the Division of Petroleum Chemistry, Inc., and the Division of Water, Air, and Waste Chemistry”, American Chemical Society, San Francisco meeting

18. Laherrere, J.; (2005) Review of Oil Shale data

19. Lee, S. and Speight, J.; (2007) Chapter 8, “Handbook of Alternative Fuel Technologies”, CRC Press, Hoboken

20. Lille, U.; (2003) Current Knowledge on the Origin and Structure of Estonia Kukersite Kerogen, “Oil Shale”, vol 20, no. 3 pp 253 -263

21. National Petroleum Council; (2007) Topic Paper #27 Oil Shales, “Working document of the NPC Global Oil & Gas Study”

22. Office of Technology Assessment Materials, US Government; (1980), “US Government Reports”

23. Petersen, H. I., Rosengberg, P., Nytoft, H. P.; (2008) Oxygen groups in coals and alginate-rich kerogen revisited, “Int. Jl. of coal geology”, vol 74, pp 93-113

24. Sleeman Consulting and GBRM; (2004) Energy for Minerals Development in the South West Coast Region of Western Australia Study Report, “Australian Government Department of Industries and Resources Report”, pp 115

25. Soone, J., Doilov, S.; (2003) Sustainable Utilization of Oil Shale Resources and Comparison of Contemporary Technologies Used for Oil Shale Processing, “Oil Shale”, vol 20, no. 3 special, pp 311-323

26. Soone, J., Riisalu, H., Kekisheva, L., Dolov, S.; (2006) Environmentally Sustainable Use of Energy and Chemical Potential of Oil Shale, “Int. Oil Shale Conf.”, Recent trends in Oil Shale, 7-9 November

27. Tasmanian Government Report; (1926), The Oil Shales of Tasmania, “UR 1926”, pp 137-144

28. Tasmanian Government Report; (1930), Oil Shales Resources of Tasmania, “UR 1930”, pp 1-7

29. Uibu, M., Uus, M., Kuusik, R.; (2009) CO2 mineral sequestration in oil-shale wastes from Estonian Power Production, “Jl of Env. Management”, vol 90, pp 1253 -1260

30. University of Kentucky; (1993) The Development of an Integrated Multistage Fluid Bed Retorting Process, “Quarterly Technical Report for the Period 01 Jan’93 to 31 Mar’93”

31. US Dept. Of Energy; (2004) Strategic Significance of America’s Oil Shale Resource, “Volume II, Oil Shale Resources Technology and Economics”

32. US Dept. of Energy; (2007) Secure Fuels from Domestic Resources, “The Continuing Evolution of America’s Oil Shale and Tar Sands Industries”

33. Vagnetti, R. (US Dept. of Energy); (2006) Can Shale Oil and Water Mix? Perspectives on Water Resources and Oil Shale Development, “26th Oil Shale Symposium, Golden Colorado”

34. Vali, E., Valgma, I. and Reinsalu, E.; (2008) Usage of Estonian Oil Shale, “Oil Shale”, vol 25, no. 2, special, pp 101-114

35. Vandenbrouke, M.; (2003) Kerogen: From types to models of Chemical Structure, “Oil & Gas Science and Technology – Rev. IFP”, vol 58, no. 2, pp 243-269

36. Vego, A., Carter, S. D., Stehn, J. L.; (1993) Utilization of Spent Oil Shale in a Fluidized Bed Process, “Centre for Applied Energy Research”, University of Kentucky

37. Weissl, M. A., Ball, B. C., Barbera, R. J.; (1979) Shale Oil: Potential Economies of Large-Scale Production, Preliminary Phase, “Energy Laboratory Report No. MIT-EL 79-012WP”

Appendix A

Boss Energy Report on Bulk Sample China Flats

GHD

GHD House, 239 Adelaide Tce. Perth, WA 6004
P.O. Box Y3106, Perth WA 6832
T: 61 8 6222 8222   F: 61 8 6222 8555   E: permail@ghd.com.au

© GHD 2009

This document is and shall remain the property of GHD. The document may only be used for the purpose for which it was commissioned and in accordance with the Terms of Engagement for the commission. Unauthorised use of this document in any form whatsoever is prohibited.

Document Status

Rev No.	Author	Reviewer		Approved for Issue		
		Name	Signature	Name	Signature	Date
0	Shastri, S S	S Kamper	*S Kamper*	S Kamper	*S Kamper*	5Aug09
1	Shastri, S S	S Kamper		S Kamper		