The techno-economics of bitumen recovery from oil and tar sands as a complement to oil exploration in Nigeria

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ABSTRACT

The Nigeria economy is wholly dependent on revenue from oil. However, bitumen has been discovered in the country since 1903 and has remained untapped over the years. The need for the country to complement oil exploration with the huge bitumen deposit cannot be overemphasized. This will help to improve the country's gross domestic product (GDP) and revenue available to government. Bitumen is classified as heavy crude with API (American petroleum Institute) number ranging between 5^0 and 11^0 and occurs in Nigeria, Canada, Saudi Arabia, Venezuela etc from which petroleum products could be derived.

This dissertation looked at the Canadian experience by comparing the oil and tar sand deposit found in ***Canada with particular reference to Athabasca*** (**Grosmont, Wabiskaw McMurray and Nsiku**) with that in Nigeria with a view of transferring process technology from Canada to Nigeria. The Nigeria and Athabasca tar sands occur in the same type of environment. These are the deltaic, fluvial marine deposit in an incised valley with similar reservoir, chemical and physical properties. However, the Nigeria tar sand is more asphaltenic and also contains more resin and as such will yield more product volume during hydrocracking albeit more acidic. The differences in the components (viscosity, resin and asphaltenes contents, sulphur and heavy metal contents) of the tar sands is within the limit of technology adaptation. Any of the technologies used in Athabasca, Canada is adaptable to Nigeria according to the findings of this research.

The techno-economics of some of the process technologies are x-rayed using the PTAC (Petroleum technology alliance Canada) technology recovery model in order to obtain their unit cost for Nigeria bitumen. The unit cost of processed bitumen adopting steam assisted gravity drainage (SAGD), in situ combustion (ISC) and cyclic steam stimulation (CSS) process technology is 40.59, 25.00 and 44.14 Canadian dollars respectively. The unit cost in Canada using the same process technology is 57.27, 25.00 and 61.33 Canadian dollars respectively. The unit cost in Nigeria is substantively lesser than in Canada. A trade off is thereafter done using life cycle costing so as to select the best process technology for the Nigeria oil/tar sands. The net present value/internal rate of return is found to be B$3,062/36.35% for steam assisted gravity drainage, B$1,570/24.51% for cyclic steam stimulation and B$3,503/39.64% for in situ combustion. Though in situ combustion returned the highest net present value and internal rate of return, it proved not to be the best option for Nigeria due to environmental concern and response time to production. The best viable option for the Nigeria tar sand was then deemed to be steam assisted gravity drainage.

An integrated oil strategy coupled with cogeneration using MSAR was also seen to considerably amplify the benefits accruable from bitumen exploration; therefore, an investment in bitumen exploration in Nigeria is a wise economic decision.

KEY WORDS

Bitumen and power generation

Extraction technology

Investment advantages

Integrated oil sand strategy

Quantitative/Qualitative research work

Recovery model

Life cycle costing model

Financial figures of merit

Net present value

Life cycle costing simulation

Cyclic steam stimulation

Cost benefit ratio

In situ combustion

Comparative analysis

Multiphase superfine atomised residue

Unconformity

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Break-even point

Internal rate of return

Unit cost

VAPEX

SAGD

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List of Acronyms

AEUB	Alberta energy utility board
App. Ǿ	Approximate porosity
B/C	Benefit cost ratio
B$	Billion Dollar
CA$	Canadian Dollar
CAPP	Canadian association of petroleum producers
CDN	Canadian Dollar
CES	Clean energy system
CHOP	Cold heavy oil production
CSEG	Canadian society of exploration Geophysicist
CSS	Cyclic steam stimulation
DPK	Dual purpose kerosene
EIA	Environmental impact assessment
Fm(s)	Formation(s)
GCU	Geological consultancy unit
GHG	Green house gas
GJ	Giga joule
GOR	Gas oil ratio
IRR	Internal rate of return
ISC	In situ combustion
Kwh	Kilowatt hour
LCC	Life cycle costing
LPG	Liquefied petroleum gas

MSAR	Multiphase superfine atomised residue
MSMD	Ministry of solid minerals development
MW	Megawatt
N/A	Not applicable
NNPC	Nigerian national petroleum corporation
NPV	Net present value
ODSG	Ondo State Government
OOIP	Original oil in place
PMS	Premium motor spirit
PPMC	Petroleum product marketing company
PTAC	Petroleum technology alliance Canada
QFI	Quadrise fuels International
SAGD	Steam assisted gravity drainage
SAGP	Steam assisted gravity pressure
SOR	Steam oil ratio
VAPEX	Vapour extraction
Wt %	Weight percent
WTI	West Texas index

CHAPTER ONE

1.1 OVERVIEW

Bitumen was discovered in Nigeria in the early 18th century. The interest of the colonial masters in Nigeria was to explore this all important mineral. However, the discovery of oil in the early 1960's in commercial quantity brought to a close the exploration of bitumen in Nigeria.

Crude oil exploration, though the major foreign exchange earner of the country has been with its attendant problems often resulting in huge lose of revenue to government. Canada does not have crude oil but rather oil and tar sands and heavy oil and has put these into good usage. It is therefore necessary for Nigeria to look inward and provide a complement for crude oil exploration. Bitumen as found in Nigeria is a grade of crude oil and occurs in large commercial quantities with both chemical and physical characteristics similar to those of Athabasca in Canada

Against this background therefore, it will be possible to transfer process technologies as used in Athabasca to Nigeria so as to increase the income earning capacity of the country.

The history of bitumen in Nigeria dated as far back as 1903. Between 1908 and 1912 the Nigeria Bitumen Corporation, one of the first companies to explore the Nigeria bitumen ore deposit drilled 15 wells in the Lekki lagoon with oil struck in November1909. (Phia Steyn, "XIV International Economic Congress, Helsinki, 2006, Session 11"). In the early 80's, the Geology Department of Obafemi Awolowo, Ile-Ife (known then as The University of Ife) made some deductions (both scientific and economic) as to the availability in commercial quantity of bitumen in the country.

Adelu & Fayose (1991), Omatsola & Adegoke (1981), Billman (1976), Rayment (1965) did many research work on the geology of the bitumen ore deposit in Nigeria and categorised the oil sand as Araromi Shale formation, Abeokuta formation, Nkporo shale, lower cretaceous, upper cretaceous, lower senonian, Afowo formation, albian sand and Ise formation etc with prediction that there are minor dissimilarities between the Nigeria bitumen and Athabasca oil sands.

Over the years, every attempt by the country to develop the ore deposit has been unsuccessful. On February 17 2003, the Federal government of Nigeria put in place an Implementation Committee for the bitumen exploration. The work of the Committee yielded no positive outcome.

On 16 June, 2003, the Vanguard newspaper reported that the Bitumen Project Implementation Committee (BPIC) headed by Professor Ihonvbere threatened to withdraw the license granted two companies (Nissan Limited and BEECON Consortium) due to non-performance.

The occurrence of Athabasca bitumen which is also referred to as tar sand is found in the McMurray formation. The formation occurs in the lower cretaceous in an area of unconformity around Devonian carbonate rocks showing signs of denudation on the surface. In most cases, the sand is unconsolidated showing grain size transiting between fines to coarse quartz sand varying in thickness. The sand exhibits the following characteristics; net pay zones, twenty to forty meters, porosity, thirty to forty percent and weight percent between ten and eighteen percent (AUEB 2003)

1.2 PROBLEM STATEMENT

Bitumen has been discovered in Nigeria since 1903. Over the years, this resource has remained untapped even though it is ranked second largest in the world. The Nigeria economy is a monolithic one; that is oil exports contribute twenty percent to her gross domestic product; ninety-five percent to foreign exchange earnings and when budgets are drawn provides sixty-five percent of the revenue. There is therefore the need for the country to complement oil exploration with the huge bitumen deposit that is available.

The question then arises: What is the preferred process technology for exploring Nigeria's bitumen resources and what is its economic viability?

An investigation into the Canadian experience (vis-à-vis quality of tar sand and technology used with cost implication) will be used as a baseline to develop the preferred approach for monetising Nigeria's bitumen deposit. The Canadian experience with reference to various process technologies will serve as a benchmark for the understanding and transfer of process technology for the exploration of the Nigeria tar sand deposit. An appraisal of the techno-economics of these technologies will assist in adapting one to the Nigerian environment.

1.3 RESEARCH OBJECTIVES

This research work,

1. Investigates the similarities and differences between the Nigeria bitumen deposit and Athabasca sand in Canada and the possibility of adapting the technology used in developing the deposits to the Nigerian environment.

2. Investigates the economic viability of the exploration of this resource with available technologies with a project life cycle of ten years setting 2008 as the base year.

3. Provides recommendations to the country (Nigeria) and would-be investors on the possibility of the exploration of bitumen to complement oil exploration in Nigeria.

1.4 OVERVIEW OF DISSERTATION

This research work will be structured in the format below:

- Chapter 1(Introduction) discusses the dissertation via a background and the problem statement. The objectives of the research that led to the specific research/problem statement will be presented.
- Chapter 2 (Literature review) will examined valid literature for availability of bitumen/oil and tar sands in commercial quantity and its geology in Nigeria, the geology and quality of the Athabasca tar sand and available technology for the exploration and development of bitumen.
- Chapter 3 (Empirical Investigation) will undertake a comparative analysis of Athabasca and Nigeria tar sand and the cost analysis of the process technology- PVB, PVC, NPV, B/C and IRR using whole life cycle costing software and analysis and the PTAC technology recovery model.
- Result of findings in chapter three will be documented in chapter four.
- In chapter five, the findings will be discussed and interpreted to pinpoint the credence they give to the dissertation and with a view to drawing inferences and conclusion.
- Finally, in chapter six, conclusion relating to the stated research statement will be presented and recommendation for further research will be made.

2.0 LITERATURE REVIEW

2.1 NIGERIA OIL AND TAR SANDS DEPOSIT

Two companies, The Nigeria Properties Limited and the Nigeria and West Africa Syndicate Limited could be credited with the development of the oil industries in the country. The two companies started exploring for bitumen, petroleum and coal in 1903 with two concessions covering a 400 square miles territory in the Lekki lagoon of South Western Nigeria.

Bernard A. Collins (1903-4 and 1904-5) and A.H Harrison (1904-5) in their geological investigation reported the following:

"Notwithstanding the shallow depth at which the deposits occur and the tropical heat of the territory, the bituminous deposits so far located are in a plastic condition; this seems to show that there is still a flow of liquid from the original source and gives the expectation that oil exists in considerable quantity" (The Times, 8 November 1905, page 15a)

This report attracted John Simon Bergheim, a British businessman who founded the Nigeria Bitumen Corporation in November 1905 with the sole aim to acquire the concessions of the two companies mentioned above. The Nigeria Bitumen operations shifted quickly from bitumen to oil under their Manager who happens to be a practical oil operator. In 1906, the company acquired the property and concession of the Northern Nigeria Exploration Syndicate (Limited) adjacent that of the Nigeria Bitumen Corporation. Bergheim wanting to please the board reported that 500 tonnes of bitumen had been transported to Britain while the company was at this stage still looking for a buyer and market.

Under the supervision of one Mr Van Sickle, the Nigeria bitumen drilled 15 wells in their Lekki lagoon between 1908 and 1912. It struck oil in November 1909. The company could not explore their finds profitably as it had to contend with water intrusion problems around Makun well. (XIV International Economic Congress, Helsinki 2006, Session 11)

The death of Bergheim in 1912 caused the Nigeria Bitumen Corporation to be liquidated in 1914. Further interest in the exploration of bitumen in the country was stalled due to World War II. Between 1904 and 1970 surface occurrence were explored with about 40 wells, boreholes and exploration wells. Efforts by the following companies at different periods were very significant: -

- Between 1908 and 1914, Nigeria Bitumen Corporation
- Between 1936 and 1960, Shell D'Arcy
- Between 1936 and 1966, Tennessee Nigeria Incorporated.

In the late 70's and early 80's, the geological consultancy unit (GCU) of Obafemi Awolowo University, Ile-Ife (formerly University of Ife) carried out a comprehensive study on an area of the deposit measuring seventeen square kilometres and deduced that the deposit has economic value with favourable geology for both exploration and exploitation.

2.1.1 ATTEMPTS AT DEVELOPING THE NIGERIAN OIL AND TAR SANDS DEPOSIT.

Attempts at developing the Nigeria bitumen dated as far back as 1905 with the Mineral Survey of Southern Nigeria. About sixteen (16) shallow boreholes were drilled in the tar sand belt. Some of the wells near Mafowokun and Eregu valley, struck bituminous sections ranging from 4m to 9m with overburden thickness generally less than 7 meters. Next to this attempt was the one carried out by Nigeria Bitumen Corporation (1907 to 1914). The Company drilled fifteen (15) boreholes near Sumoge, Oso, Mofere, Oke Oyibo and Oniparaga east of the area investigated by Mineral Survey group. (Phia Steyn (2006))

Some of the boreholes encountered bitumen impregnated sand with the thickness of about 286.6 metres as well as large quantity of sulphur. Eleven of the borehole struck basement complex. One of the boreholes at Agbabu (NBC-7) encountered black heavy oil with the well being sub-artesian is still there till date.

Between 1937 and 1958, Shell D'Archy which left at the outbreak of World War II came back as Shell BP and drilled six (6) wells. Three of them (Araromi – 1, Gbekebo – 1 and Benin – West 1) were very promising. Gulf Oil Corporation of Pittsburgh, USA, in 1954 examined some bituminous sample from Aiye and Irele. Crockett and Wescott who authored the report of the company concluded that the oil sands were suitable for road surfacing and asphaltic mixes.

Other attempts were those by Mobil Exploration (Nigeria) between 1959 and 1968. Wells drilled include Bodashe-1, Ilepaw-1, Oyo-1 and Afowo-1, the only well with hydrocarbon trace. Tennessee Nigeria Incorporated attempts in 1966 were also not successful due to low volume yield of the OML acquired North-East of the Lekki Lagoon (OML 474).

Between 1974 and 1980, the Geological Consultancy Unit, Obafemi Awolowo University Ile-Ife, known then as the University of Ife, in collaboration with TESCO of Hungary drilled a number of boreholes to understudy the Nigeria bitumen. Their work is still the most detailed and extensive to date. They concluded that the bitumen impregnated sand could be continuous in the subsurface and could be used in road construction and petrochemical industries. Based on their lab result, they also predicted the use of hot water process for the recovery of about 31 billion barrels of bitumen in place.

Based on the 1976 report, the GCU drilled four additional deep boreholes for confirmation, consequent upon which it was commissioned by the Ondo Sate government to carry out a detailed study of a 17 square kilometre area north of Agbabu. Thirty Eight of the forty four boreholes drilled in a modified grid pattern recorded bituminous sections with net thickness between 4m and 33m.

"The Nigerian National Petroleum Corporation (NNPC) acquired one hundred and fifty (150) line kilometres of 2-D seismic data comprising three E – W running strike lines and two NE-SW diagonal dip lines" in 1978. The outcome of the lines in terms of processing and interpretation is not known. Most recently, between October 2002 and July 2005 a total of sixteen (16) core-holes were drilled in different locations, which show the prominence of high tar sands and bituminous deposit (http://msmd.gov.ng/Bitumen%20Bid%20Memo.pdf)

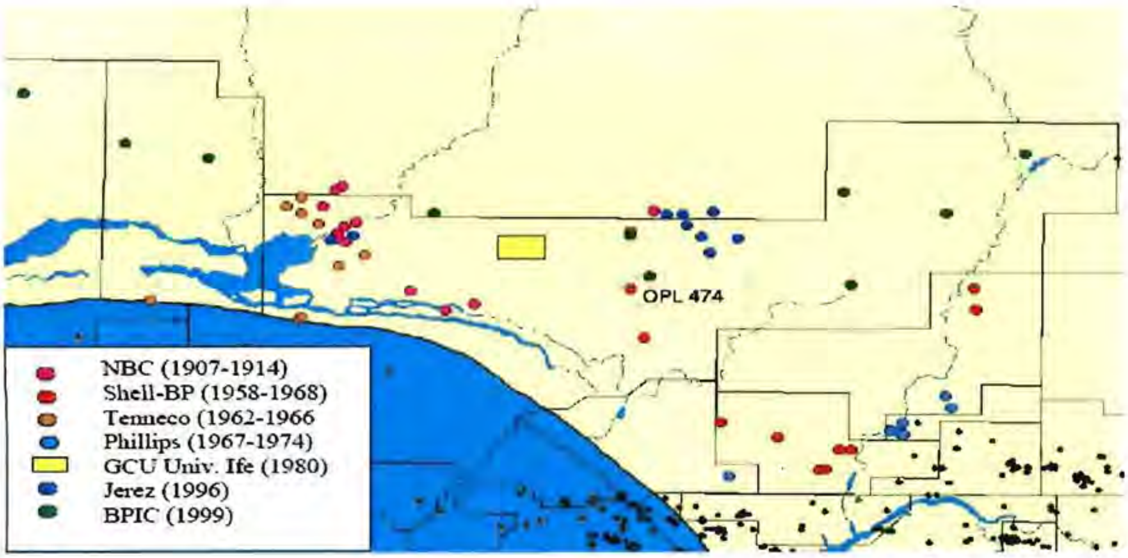

Figure 1: Historical well and borehole data in the vicinity of block 474 courtesy of Ministry of solid mineral development, March, 2006

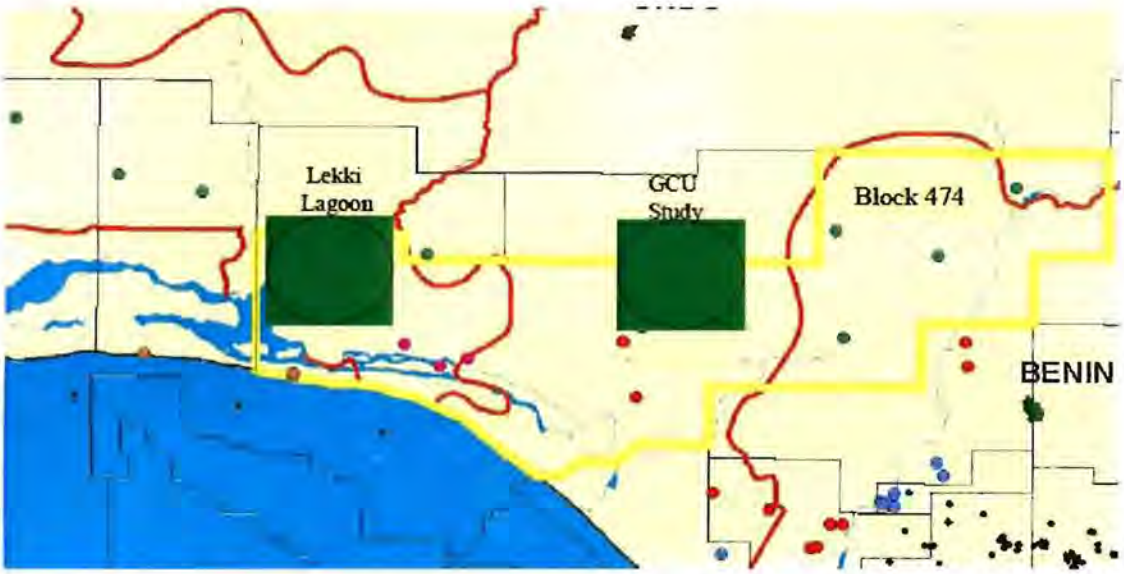

Figure 2: Two focal Areas of well control in and around BLOCK 474 (Ministry of solid minerals 2006)

2.1.2 OCCURRENCE

Bitumen occurs as extra heavy crude. The remains of organisms like foraminifera, algae, corals, e.t.c are naturally buried in the soil. The remains change to light crude at certain depth. In the crust, rise by capillarity could cause the light crude to migrate upward and in doing so is fed upon by bacteria in aquifers. The process removes the lighter components of the crude and leaves the heavier parts behind. As the crude migrates further up, the heavier crude is turned to bitumen. This event could take million of years. (Professor E.A Fayose (2004))

2.1.3 DISTRIBUTIONN AND CLASSIFICATION

Oil is classified according to its API (American Petroleum Institute) number. Based on the API number, oil is divided into three categories.

- $5^0 - 11^0$ as bitumen
- $12^0 - 25^0$ as heavy crude
- $>26^0$ as light crude.

Bitumen is found in Ondo, Lagos, Ogun, Edo and Enugu States. In these areas, five types of hydrocarbon occurrence are known within the tar sand belt in these States. The occurrences are: "Outcrops, Rich sands, Lean sands, Shale and Deep seated heavy crude" (Professor E.A Fayose 2004: Bitumen in Ondo State)

"The term "tar sand" is only applicable to the first three types of occurrence that have bitumen content above 10%wt. They are composed basically of sand, bitumen, water and some mineral accessories. The tar sands with 5-10%wt of bitumen are designated as good or medium grade" (Professor E.A Fayose 2004: Bitumen in Ondo State)

2.1.4 GEOLOGY

Bitumen is found in the eastern end of the Benin basin (coastal sedimentary basin). The basin covers the five West African countries coastline (Ghana, Ivory Coast, Togo, Benin republic and Western Nigeria. "The basin which is formed during the early block faulting formed part of the geological events which led to the opening of the Atlantic Ocean. Sediments were eroded from the elevated area and deposited in the depressions of grabens in which the most stratigraphical sequences are preserved". (http://ondostategovernment.net/pdf/Bitumen.pdf).

Omatsola and Adegoke (1981) classified the formation into three categories from top to bottom (Araromi, Afowo and Ise formations). "The maximum thickness encountered in Ise -1 well was 609 meters. Similar sections are also revealed near Ode-Remo along the Lagos - Ibadan express way and along the Ose River" (Professor E.A Fayose 2004). Palynomorph content revealed the formation age as Neocomian.

According to Adelu and Fayose (1991), Afowo formation succeeds the Ise formation which in most places has fine to medium grained sandstones in its matrix. In between the beds are siltstones and shale of relative thickness. The shale which increases from bottom to top is found to be rich in fossils. The formation is otherwise known as the transition formation and reaches a maximum thickness of 430 meters. "In some areas, the Afowo formation is seen to overlie the basement directly and has been found to be bituminous in both surface and subsurface sections. The age of this unit is Mastrichitian and is exposed east of Ifon". (http://ondostategovernment.com/)

At the top of the Abeokuta group is Afowo formation. The stratum is arranged with sand and lignite at the top, followed by siltstone and mixture of shale and bitumen and sand at the base. Both the sands and clay are bituminous in many places.

Generalized Lithology	Formation	Age		Thickness (feet)	Comments
	Benin Fm., Coastal Plains Sands	Tertiary	Pleistocene - Oligocene	0 – 1600	coastal-plain clastics
	Oshosun – Ilaro – Ameki Fms.	Tertiary	Eocene	200 – 1000	fluvial and marine sands and clays
	Ewekoro Fm.	Tertiary	Paleocene	400 – 1000	marine shale, limestone
	Araromi Fm. Abeokuta Fm.	Cretaceous	Maastrichtian	500 – 1000	coastal sand, shale; marine shale
	Afowo Fm. Turonian Sst. Albian Sst.	Cretaceous	Campanian - Aptian	0 – 800	marine sandstone, shale, limestone
	Ise Fm.	Cretaceous	Barremian - Neocomian	0 – 6000+	continental and lacustrine rift-basin fill
	crystalline basement (undifferentiated)	Cambrian - Precambrian			metamorphic and igneous complex

Figure 3: Generalised stratigrapic column of the Nigerian bitumen deposit (Ministry of Solid Minerals Development 2004)

Table 1 – Stratigraphy of Cretaceous – Paleocene of Benin Basin (Professor E.A Fayose 2004)

RAYMENT 1965 *ADEGOKE 1969*	*BILLMAN* *1976*	OMATSOLA & ADEGOKE 1981		*AGE*
Araromi Shale (Informal)	Nkporo Shale (Lower Paleocene Upper Cretaceous Awgu Formation (Lower Senonian Turonian	Araromi Formation	ABEOKUTA GROUP	UPPER CRETACEOUS TO PALEOCENE
Abeokuta Formation	Abeokuta Formation (Turonian)	Afowo Formation		MID-LATE CRETACEOUS
	Albian Sands Older folded Sediments	Ise Formation		NEOCOMIAN

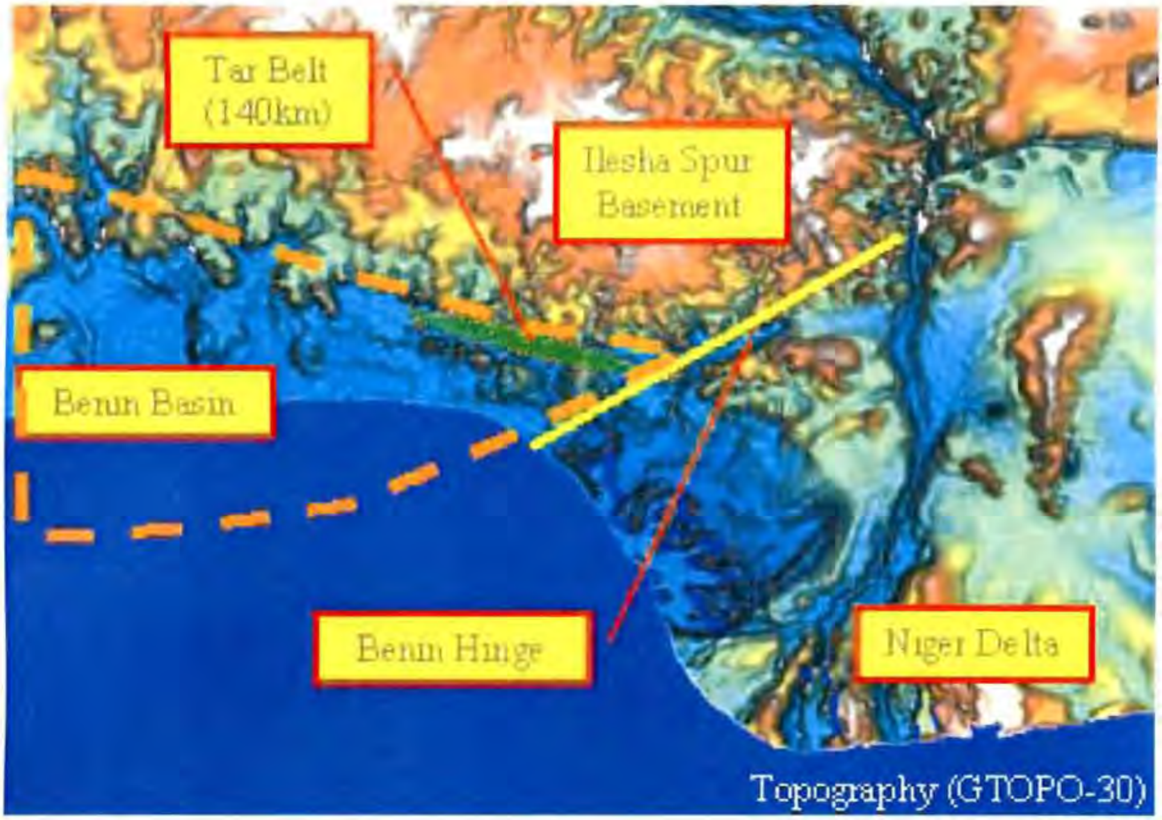

Figure 4: Key Structural elements of the bitumen formation in Nigeria (Ministry of Solid Minerals Development 2004)

The work by these authors is relevant to this dissertation and will be used in the comparative analysis section in chapter four.

2.1.5 RESERVES ESTIMATE

According to ERA (Environmental Right Action) report (November 2003), bitumen reserve in Nigeria is about fifteen million barrels. The bulk of this reserve which is in South-Western Nigeria covers an estimated area of about 189 km^2. The thickness of the zone is about twenty meters with very high mean hydrocarbon content. This reserve is estimated to be the second largest in the World.

Based on the work done by the GCU, Adegoke et al, (1976) put the reserve estimate to be about thirty-one billion metric tones and that for commercial exploration at five hundred and forty million metric tonnes. According to Coker (1976) "the bulk volume of the bituminous sand up to 50m depth extractable by open cast mining is about 25billion metric tonnes and 621 million barrels of bitumen in place". (http://ondostategovernment.com/) Using a recovery factor of 85% he calculated the volume of bitumen in situ to be of the order of 528 million barrels. Edjedawe (1978) calculated the hydrocarbon potential of the resources of the Okitipupa structure to be about one billion, five hundred million barrels (103.6 barrels/km^2)

The work by these authors seems hypothetical. However, the reserve estimate as reported by Coker (1976) is used in the techno-economic analysis in chapters three, four and five.

2.1.6 DEPOSIT CHARACTERISTICS

The basic characteristics of the type of bitumen encountered in Nigeria have been considered under the API gravity, crude viscosity, sulphur content, asphaltenes and carbon residue. (Professor E.A Fayose 2004: Bitumen in Ondo State)

There are large impressive outcrops around Idiobilayo with tar impregnated sand N45^0E within 900m distance from the village. The outcrops tar impregnated sand has variable thickness (3.5m to 4m) covered with about 7.5m - 8m thick overburden.

According to Prof. E.A Fayose (2004) "The area surrounded by Foriku to the north, Agbabu to the south, Aiyabi to the east and the railhead to the west is also very rich in bituminous deposits and contains thick bituminous sections. The sections have an average thickness ranging between 4m-32m with relatively thin overburden sections and consequently, good stripping potential" (http://www.ondostategovernment.net/)

2.2 GEOLOGY OF THE CANADIAN OIL SAND

There are four major bitumen bearing carbonate formation in Alberta, Canada, for which volume in place have been determined. These are Athabasca (Grosmont and Nsiku) and Peace River (Debolt and Shunda) (Alberta Energy and Utility Board 2006)

The Athabasca oil sand in Alberta, Canada, is classified into three major oil sands areas from highest to lowest volume of reserves-in-place, Athabasca, Cold Lake, and Peace River (AEUB 2003). According to M. Gingras & D. Rokosh et al. 2004, "The oil sands reserves occur primarily in the cretaceous upper and lower Manville (73%) formation, with lesser amounts in the Denovian Grosmont (19%) and Nisku (4%) formations, the Carboniferous Debolt (3%) and Shunda (1%), and Belloy (Trace)"

2.2.1 ATHABASCA OIL AND TAR SANDS.

The McMurray formation sits right on an "angular unconformity that truncates Devonian strata. To the east, the strata are mainly of limestone and calcareous shale of the waterway formation and younger carbonate rocks of the Woodbend group to the west". The thickness of the pay zones ranges from 20-40m with porosity of 30-40% and 10-18wt% of bitumen. (M.Gingras & D. Rokosh 2004: CSEG National Convention)

The McMurray formation occurs in incised valleys formed by fluvial processes and marine marginal transgression in the earlier cretaceous sea level rise. The formation displays continuous sedimentary environment from fluvial to estuarine and marine shore-face in that order from lower to top.

The three fold stratigraphic classification of the McMurray formation was first proposed by Carrigy (1959). He divided it into the lower, middle and upper units which remained till date. The division remained and could not be formalised because it is not map-able and also vary from place to place though they do have lithological expressions in some places.

The lower McMurray has medium-coarse-grained cross bedded deposits that contain ichnofossils. The bed is fluvial in nature. The middle McMurray contains brackish water trace assemblage which is a pointer to a heterolithic stratification interpreted as tidally influenced deposition. (Pemberton 1982)

The upper McMurray being variable contains open marine signal. The strata is shallow, low energy shore-faces deposit and small deltaic complex (Ranger and Calpin 2003)

2.2.2 COLD LAKE OIL SANDS

In the cold lake region, the Clearwater formation is the attention of all investors. The oil sands here are on average 2-3 times thicker than any other targets of interest in other formations. The Grand Rapids is better off because it has higher bitumen saturation. As one moves southwards from Athabasca, the lithology changes facies to "near-shore deltaic and foreshore/shoreface complex". The target of interest here includes "the stacked distributaries mouth bar sequence", stated by Taylor (1992) and the non-marine and fluvial and high-energy tidal sand flat deposits", stated by McCrimmon and Arnott (2002) (M.Gingras & D. Rokosh 2004 CSEG National Convention)

The Upper Grand Rapids to a larger extent is a classical example of a deposition in a brackish water environment close to the shore. This indicates that it is formed in a marine condition better than in the lower Grand Rapids and upper Clearwater. (Benyon and Pemberton 1982)

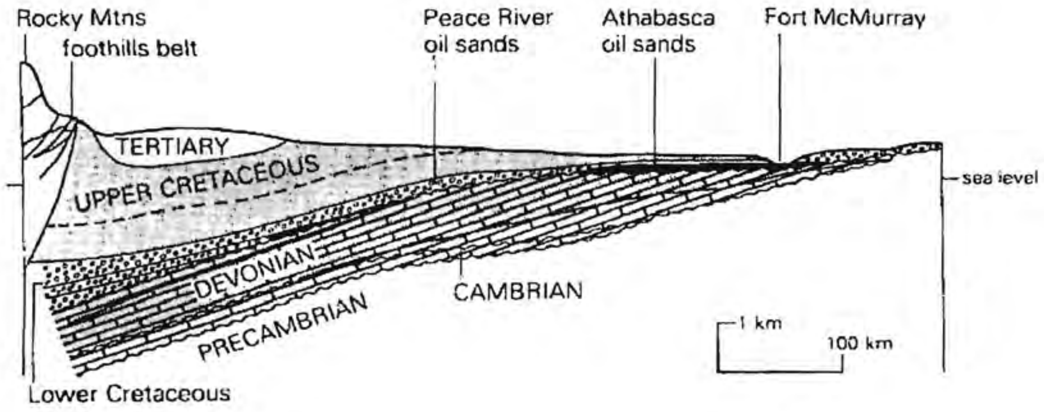

Figure 5: Cross section of Alberta Basin (F.K North 1985)

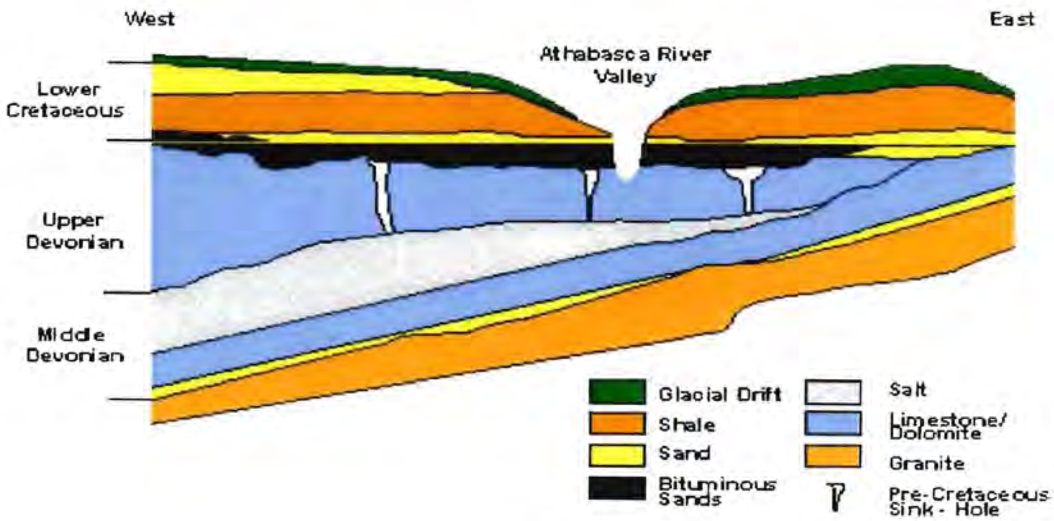

Figure 6: Simplified Cross-section through the Athabasca oil sand region (Carlgy and Krammers 1973)

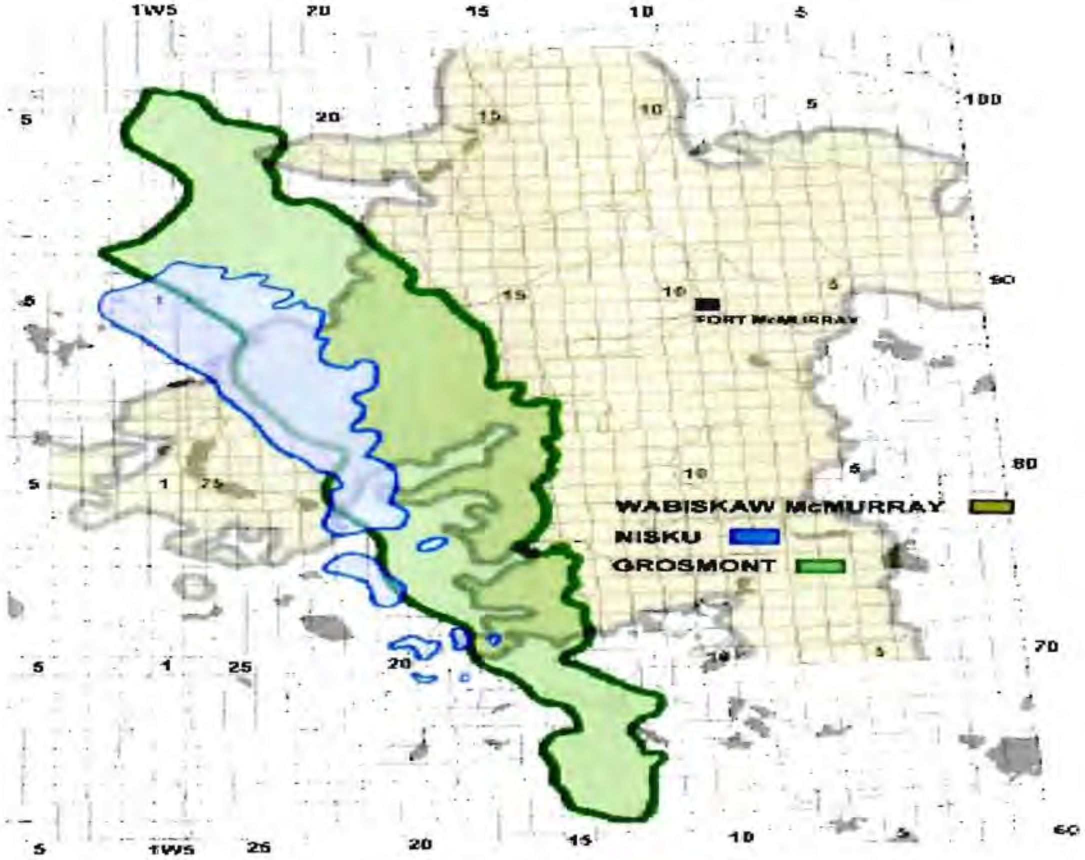

Figure 7: Athabasca bitumen deposit adapted from Alberta energy and utility board 1996 and 2006

The work by these authors is relevant as they form the basis for the comparative analysis in chapter four of this dissertation

2.3 BITUMEN EXPLORATION AND EXTRACTION TECHNOLOGIES

Various technologies have been proposed, developed and tested for the recovery of bitumen from oil and tar sands. There have also been modifications of some of these technologies. Pioneering these inventions are the United States, Canada and Venezuela. The drive to pioneer these inventions is connected to the fact that larger percentages of world bitumen deposit are found in these countries. Another drive is the fact that world economy and power are deeply rooted in petroleum products trade.

For the purpose of this research work however, these technologies vis-à-vis steam assisted gravity drainage (SAGD), cyclic steam stimulation (CSS), in situ hydrovisbreaking, imbibition flooding and hot water bitumen extraction are reviewed with the sole aim of process technology adaptation.

2.3.1 SAGD (STEAM ASSISTED GRAVITY DRAINAGE)

2.3.1.1 OVERVIEW OF THE TECHNOLOGY

The concept of SAGD was conceived by Dr Rogger Buttler around 1969 for Imperial Oil. The concept was first tested by Imperial Oil in a pilot project at Cold Lake. The test of the concept by AOSTRA in the early 80's showed its feasibility of being able to achieve 2,000bbls/day production rate from three well pairs.

The technology involves drilling of horizontal well pairs into the formation. Some set of well pairs will function as the injection well through which steam or liquid hydrocarbon access the formation and dissolve the bitumen in situ. The other set of well pairs act as the production well through which the dissolved bitumen is lifted to the surface.

According to T.N Nars (2004), SAGD proved to have very high recovery rate based on field tests. From conventional oil prospecting, drilling horizontal wells also proved to be cheaper. These two discoveries made SAGD economically attractive to any bitumen extracting and processing company.

2.3.1.2 CURRENT APPLICATIONS

Until the early 90's, drilling operations were done using traditional method. In the 21st century however, the high cost of crude has driven oil prospecting companies to employ unconventional means like SAGD to extract oil. Today, many SAGD projects are in place either fully operational or at test stage in Venezuela and Canada where most of the world largest deposit are found. The technology has increased the proven reserve in Alberta to 179 billion barrels.

2.3.1.3 DISADVANTAGES

Some disadvantages of the technology include

1) It uses large volumes of fresh water and high energy intensity to produce steam.

2) The reservoir should be thick and homogenous because it uses gravity drainage

2.3.1.4 ALTERNATIVE METHODS

According to Wikipedia, Alternative enhanced oil recovery mechanisms include VAPEX (for Vapour Extraction) and ISC (for In Situ Combustion). "VAPEX uses solvents instead of steam to displace oil and reduce its viscosity. ISC uses oxygen to generate heat that diminishes oil viscosity; alongside, carbon dioxide generated by heavy crude oil is displaced toward production wells". (http://en.wikipedia.org/)

Variation of SAGD includes SAGP and Expanded solvent-SAGD which utilise a mixture of steam and condensable or non-condensable gas. Documentary evidence of successful use of SAGD in Athabasca, Canada abounds.

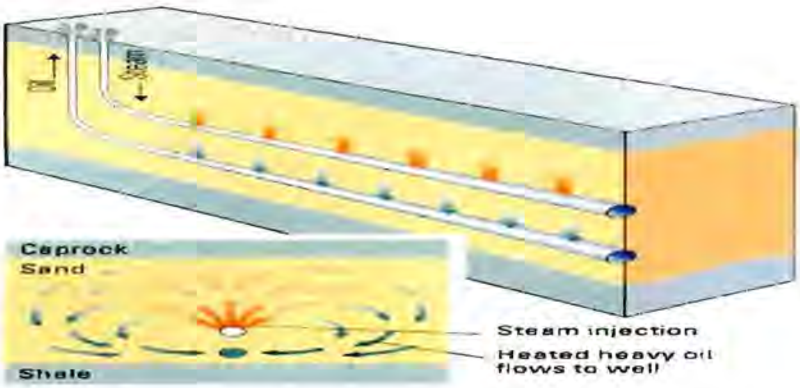

Figure 8: Concept of SAGD adapted from www.glossary.oilfield.slb.com

2.3.2 IMBIBITION FLOODING FOR BITUMEN EXTRACTION AND PROCESSING.

The process involves the drilling of boreholes through the overburden to the formation. A casing string is then run into the well-bore and cemented in place. At the pay zone, the casing is perforated in two places (upper and lower end). An annulus is created by the lowering of tubing into the well-bore through the casing string to terminate intermediate between the upper and lower perforations.

The well is then completed by packing, cementation and other means. Surface equipment like pumps, valves, tanks etc is provided and installed using convenient piping means.

2.3.2.1 MODE OF OPERATION.

A valve at the surface is opened to allow liquid hydrocarbon into the formation through the annulus by means of gravity. If the permeability of the formation is low, fracturing has to be done and the injection of the hydrocarbon has to be along the line of fracture. A period of soak is allowed whereby the liquid hydrocarbon imbibes the formation and dissolves the bitumen in place. The mixture of liquid hydrocarbon and bitumen collects at the lower end of the formation by gravity. This is then pumped to the surface after the end of soak period using surface pump or pump placed in the borehole. The cycle is repeated until the entire pay zone has been sequentially contacted

2.3.2.2 MODIFICATION

Bore holes may be drilled in pattern and having each well undergo sequential extraction until communication is established among the wells. Thereafter, one set of wells may be used as injection wells and the offset wells as production wells. Another modification may yet be the addition of surfactant to the liquid hydrocarbon to increase the active surface properties of the aqueous fluid to increase its solubility, disperse, wet or emulsify the bitumen and hence increase the recovery rate. (http://www.patentstorm.us/patents/3978926.html)

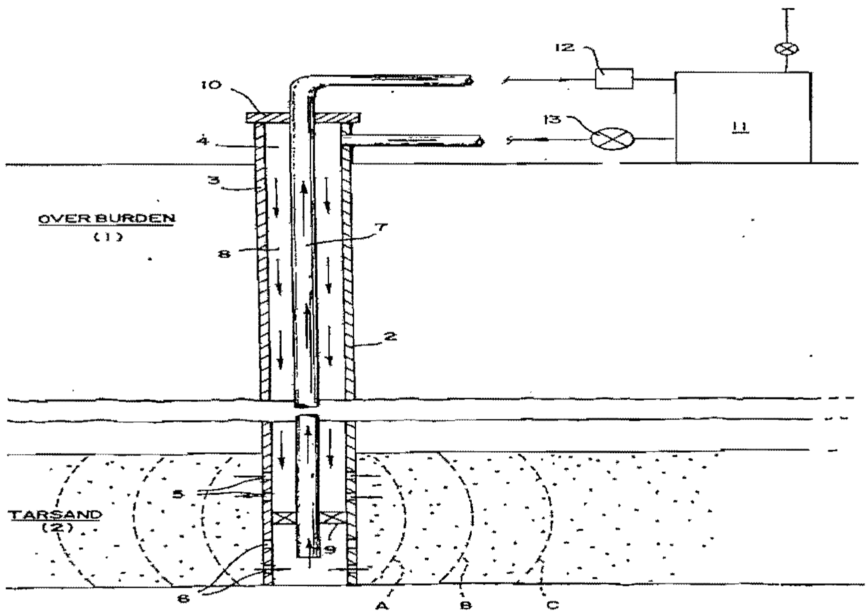

Figure 9: Imbibition flooding process using a single well adapted from Joseph C. Allen (1975) available online from www.patentstorm.us

2.3.3 HOT WATER BITUMEN EXTRACTION

Developed by John S. Rendall for SOL-EX Corporation Albuquerque, New Mexico, the process involves "using hot water extraction process to extract bitumen oil from tar sand ore combining solvent and hot water extraction with air inclusion. The tar sand ore is first conditioned in hot water and then extracted with water immiscible hydrocarbon to form a mixture which settles in phases. The mixture is then processed to give bitumen oils and recycled process components" (US Patent 3978926)

2.3.3.1 DESCRIPTION OF THE PROCESS

The invention is a process that combines both solvent extraction and hot water extraction without air floatation.

Tar sands ore is first crushed in a conditioning step to a maximum ore size suitable for further conditioning by utilising rotating mechanical augers to break down the tar-sands ore conglomerate, producing conditional small particles, referred to as tar-sands by attrition while mixing in hot water and excluding air. The conditioned tar-sands and water slurry is then screened to remove oversized inert rocks. The bitumen oils are then extracted by water immiscible hydrocarbon solvent. The solvent is recovered from the bitumen extract by distillation.

A fines removal step which comprises centrifugation then precedes the solvent recovery step and allow for an intermediate asphalt product where this is desired. The refining process could be either hydrovisbreaking with or without catalytic addition, or treatments utilising a fluidized catalytic cracker sub-critical or supercritical solvent extraction techniques. The asphaltenes residue extracted from the bitumen could be burnt to produce power and heat for the facility. The spent sand with water and fines from the mixer-settler stages are washed and dehydrated for disposal while water containing fines is clarified with the addition of flocculants, the solid materials are precipitated while the liquids are recovered and recycled. **(United States Patent Number 4,875, 998)**

The apparatus for this bitumen extraction technology includes a tar-sands crushing device and a log washer conditioner which act by dislodging bitumen oils from the solid particles of the slurry. The apparatus utilises two cylindro-conical soak vessels, each of which is paired with a sand separation vessel with a mechanical rake to remove and agitate the sand.

The spent solids are washed using two counter-current sand washers (inclined screw conveyors) with provision for injecting up-flow of wash water. Fines in the water phase are settled out of suspension in a thickener-settler with the aid of flocculants. Spent solids and fines are dehydrated using dehydrator with inclined screw conveyor and centrifuge. Solvent washed sand is recovered, separated and recycled using distillation columns and condensers.

2.3.3.2 ADVANTAGES OF THE TECHNOLOGY

Some of the advantages of this extraction process are highlighted below

1. Bitumen oils are extracted in a commercially and economically viable manner.
2. High percentage of the bitumen oils contained in the tar-sands oils is extracted.
3. Synthetic crude oils are produced which are substantially pure and free from fines and asphaltenes residue.
4. The ratio of water consumed to bitumen oils produced is very low.
5. Low grade tar-sands ore can be effectively processed.
6. The process steps are generally low temperature and atmospheric pressure operations utilising conventional equipment available in large capacity units.

2.3.3.3 DISADVANTAGES OF THE TECHNOLOGY

The following disadvantages are evident (U.S Patent no 4,875,998)

1. The process requires numerous pieces of specialised equipment

2. The process is not highly energy efficient.

3. The process is adapted for a particular type of tar-sands found at Santa Rosa, New Mexico.

2.3.4 IN SITU HYDROVISBREAKING

This invention and technology relates to a process/method for simultaneously upgrading and recovering heavy crude oils and natural bitumen from subsurface/underground reservoirs. The process utilises either a continuous operation with one or more injection and production boreholes which may include either horizontal boreholes or a cyclic operation whereby both injection and production occur in the same boreholes. (US Patent Gregoli et al. (Patent Number 6,016,867))

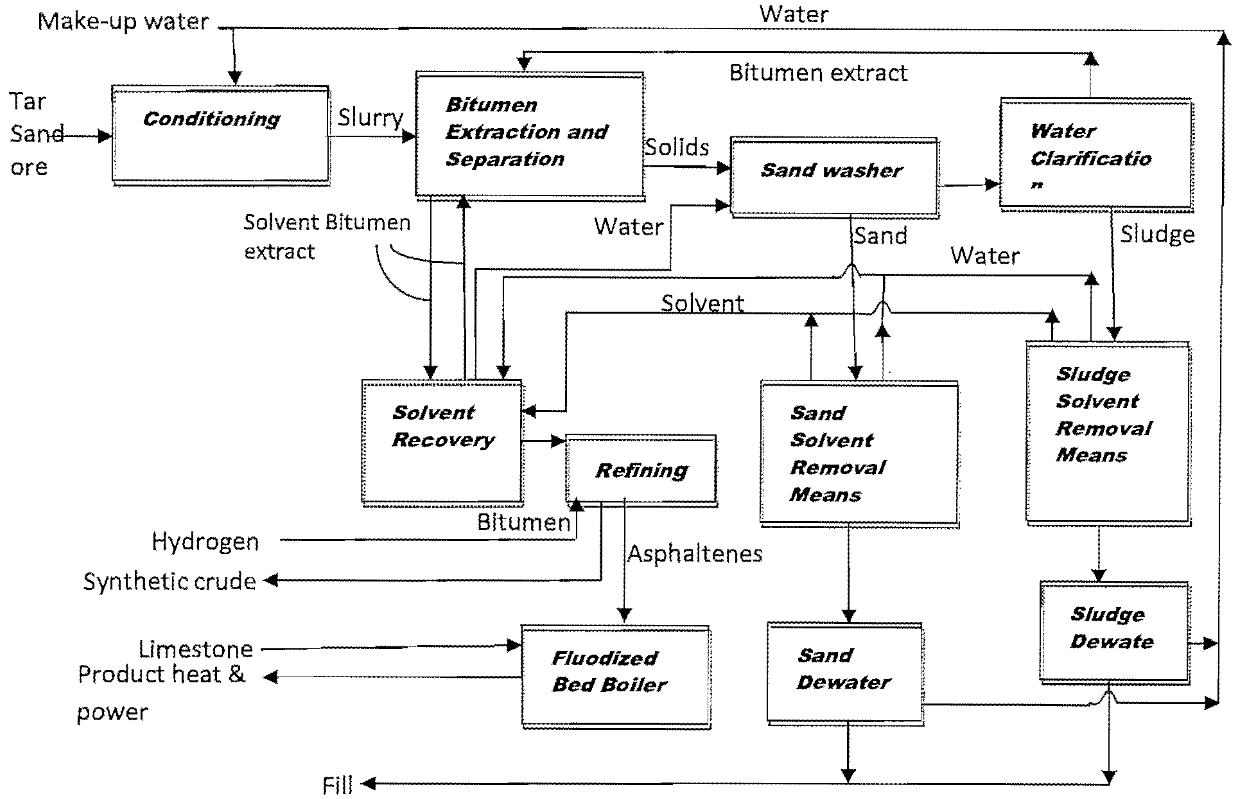

Figure 10: Simplified flow diagram of Hot water bitumen extraction process adapted from US patent number 4,875,998 October 1989 available from www.patentstorm.com

A mixture of reducing and oxidizing gases and steam are fed to downhole combustion devices located in the injection boreholes. Combustion of the oxidizing-reducing gases mixture results in the formation/production of superheated steam and hot reducing gases for injection into the formation to convert and upgrade the bitumen into lighter hydrocarbons. Communication between the injection and production boreholes in the continuous operation and fluid mobility in the cyclic operation is induced by fracturing or other related method.

In the continuous mode, the injected steam and reducing gases drive the upgraded and virgin hydrocarbons towards the production boreholes for recovery. In the cyclic mode, wellhead pressure is reduced after a period of injection causing injected fluids, upgraded and virgin hydrocarbons in the vicinity of the production boreholes to be produced. Injection and production are then repeated for another cycle. In both operations, the produced hydrocarbons are collected at the surface for further processing.

2.3.4.1 OBJECTIVE OF THE INVENTION.

The technology was developed with the following objectives.

(a) To provide a method to upgrade and recover heavy crude and bitumen in situ

(b) No combustion of the virgin crude and or heavy oil or bitumen takes place in the formation

(c) Utilisation of downhole combustion unit to generate a thermally efficient process for the injection of superheated steam and the reducing gases adjacent to the subsurface formation thereby reducing the heat loss inherent in conventional methods of subsurface injection of hot fluids.

(d) Removal of much of the capital intensive conversion and upgrade facilities required in conventional processing of heavy hydrocarbon by upgrading the hydrocarbon in situ

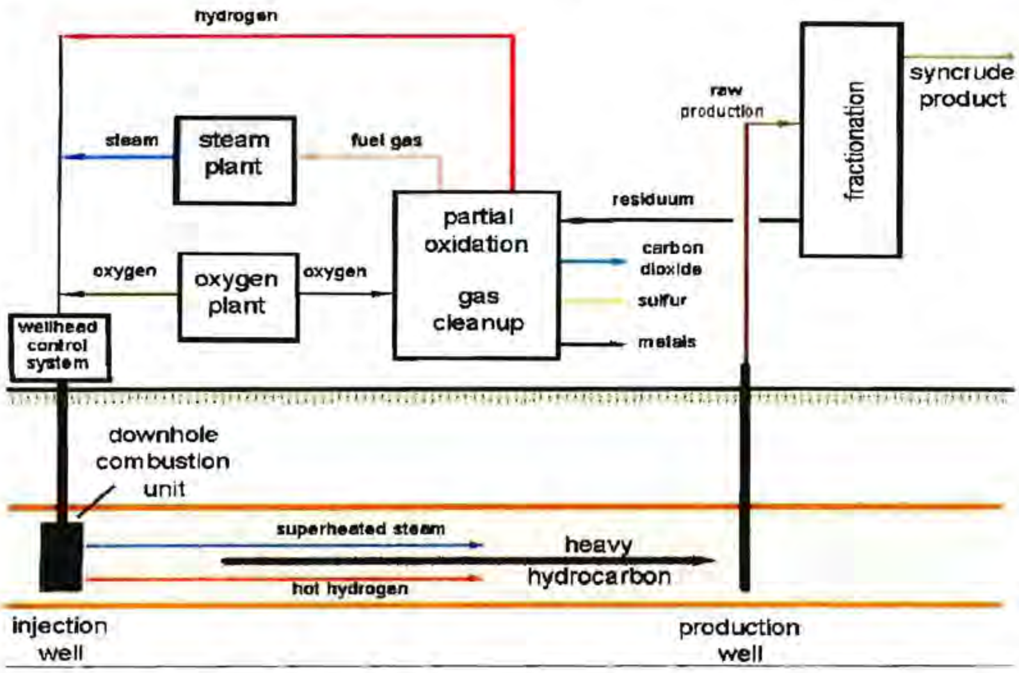

Figure 11: Process schematic for Insitu Hydrovisbreaking courtesy of Petroleum Equities Inc. 1999-2003

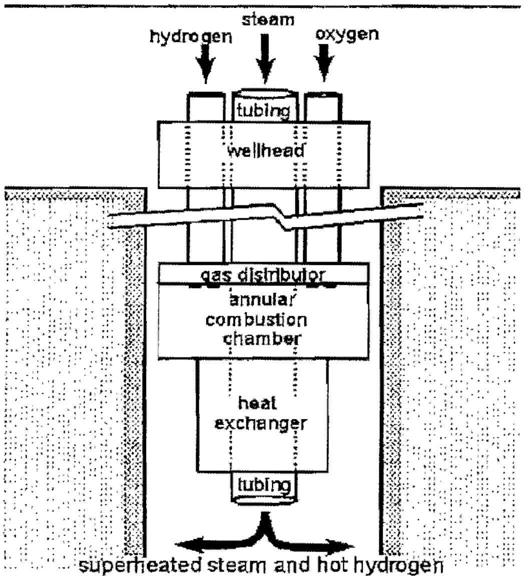

Figure 12: Down-hole Combustion Unit adapted from Petroleum Equities Inc. 1999-2003

2.3.5 CYCLIC STEAM STIMULATION (CSS).

The method involves the thinning of reservoir oil so that it will move more easily from the injection to the production wells. It could also be used as a single well procedure. The process occurs in phases. (Alberta Energy research Institute 2004)

2.3.5.1 MODE OF OPERATION.

Measured amount of steam is injected into some wells converted or drilled for that purpose. The wells are then *shut in* and allowed to stand for some time to allow for SOAKING. On the expiration of the soaking period, the injection wells are back in operation as production wells.The cycle of heat and produce or 'huff and puff' may continue until production becomes marginal due to decline reservoir pressure and increased water production.When this happens, a continuous steam injection flooding may be initiated so that some injection wells are converted to production wells or other wells are drilled for the sole purpose of steam injection.The process utilises high temperature – high pressure steam/oil mixture to fracture the oil sand in situ. "The pressure of the steam fractures the oil sand, while the heat of the steam melts the bitumen. As the steam soaks into the deposit, the heated bitumen flows to a producing well and is pumped to the surface. This process can be repeated several times in a formation, and it can take between 120 days and two years to complete a steam stimulation cycle" (http://www.oilsandsdiscovery.com/oil_sands_story/pdfs/insitu.pdf)

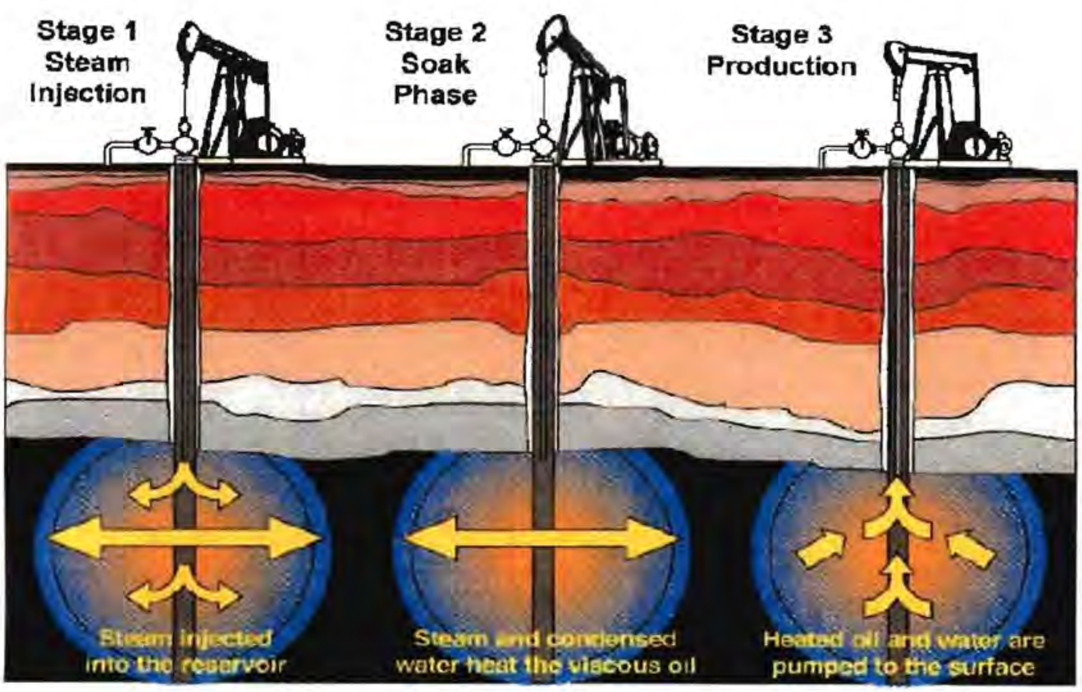

Figure 13: Cyclic steam stimulation process (Alberta Energy Research Institute, Calgary. October, 2004)

The authors above neglected the financial aspect of the technologies for bitumen extraction and focused on the technical solution. Unfortunately, a piece of technology is priced based on its viability, IRR, NPV and cash flow when in use.

The differences in feed will ultimately influence the choice of technology, for example the thickness and depth of the reservoir, the viscosity and the porosity of the oil sand as well as the chemical properties. These in turn affect the ultimate recovery and in effect the economics. For example SAGD is favoured by a thick homogenous reservoir, ISC and CSS will be more successful in shallow reservoir with relatively loose oil sand. This is captured in chapters 3 and 4 of this dissertation.

According to Singh Surindar, DU Plesis M.P, Isaacs E. E and Keer Rich (1998), SAGD holds the most promising prospect for bitumen recovery due to its lowest supply cost and high recovery rate ($56/bbl at 60-70% recovery rate with UTF (Underground test facility) and $29/bbl with surface access). "For a VAPEX processes for a reservoir- and solvent-specific operation; the `best' supply cost will be $42 per cubic meter. The ultimate recovery is similar to SAGD. They also reported that, Cold Production has almost the same supply cost as the best VAPEX process ($42.30 per cubic meter). The ultimate recovery is around 10 percent"

"The most established *in situ* technology, CSS (Cyclic Steam Stimulation), has a supply cost of $54 per cubic metres. The ultimate recovery is around 17 percent". In situ technologies are CSS, Hydrovisbreaking and Hot Water Imbibitions flooding. "The newer surface mining processes according to them will have a supply cost of $82 per cubic meter" with an ultimate recovery of about than 90 percent (Singh Surindar, DU Plesis M.P, Isaacs E.E and Keer Rich)

The work by these authors is relevant to this dissertation. Unfortunately, these costs were given without an economic model. However further analysis of the Nigeria bitumen ore deposit is required in order to establish the best process and recovery technology for the deposit vis-à-vis the chemical, physical and thermal properties of the ore. The supply costs as pointed out above are tested in the economic model in chapter four.

According to Dr Oluropo Rufus Ayodele (August 2006), bitumen and heavy oil as shown above can be recovered through any thermal-based recovery technique like SAGD, steam flooding, and CSS techniques. These techniques, although a bit specialized, are much cheaper than implementing surface mining operation. Some multinational oil companies in Nigeria, like ExxonMobil, Shell, Chevron and ConocoPhillips are already operating in situ techniques in Canada, Venezuela and some other locations around the world. He also reported that because the costs are cheaper, these companies can easily implement such operations in Nigeria and so transfer the technical know-how to the country through their other operating subsidiaries around the world. Such in situ operations will also present few barriers to indigenous investors who want to get into heavy oil and bitumen exploration and production activities.

While the work by this author is true as to the ease of technology transfer by these companies to the country (as most of them are already operating in the country), it is unlikely that all the in situ (thermal recovery methods) will be cheaper than surface mining taking into account all the cost elements involved in the operation. This is captured in chapter four and five of this dissertation.

2.4 INVESTMENT ADVANTAGES IN BITUMEN EXPLORATION AND DEVELOPMENT IN NIGERIA

The country alongside ECOWAS sub-region has a large market (about 15,000/20,000 metric tonnes per annum). The market has the capacity to grow as the present government has promised to open up the rural areas in order to decongest the cities. In order to make investment in bitumen attractive to developers, the federal government has offered many incentives in the form of waivers on tax and has also allowed foreign companies to buy into domestic companies. (Nigeria Investment Promotion Committee report, June 2004).

Other investment advantages will be in the form of technology transfer. Most of the technologies for exploration and development of bitumen ore are foreign to the country. This will ultimately benefit the country. The federal government has also promised tax reduction for equipment imported into the country for the purpose of bitumen exploration.

Other form of investment advantage is in the other sectors, vis-à-vis power and transport sectors. These sectors of the country are so poor that it has become issues of serious concern to all. The potential of the development of bitumen ore to positively affect these sectors is not in doubt. Power is one of the core requirements for bitumen exploration and development. Access to the deposit must be created. Also asphalt that is one of the main by-products of bitumen is presently being imported by the country due to the fact that the Kaduna refinery that was supposed to produce bitumen/asphalt has been out of order since 1986.

2.5 BITUMEN AND POWER GENERATION

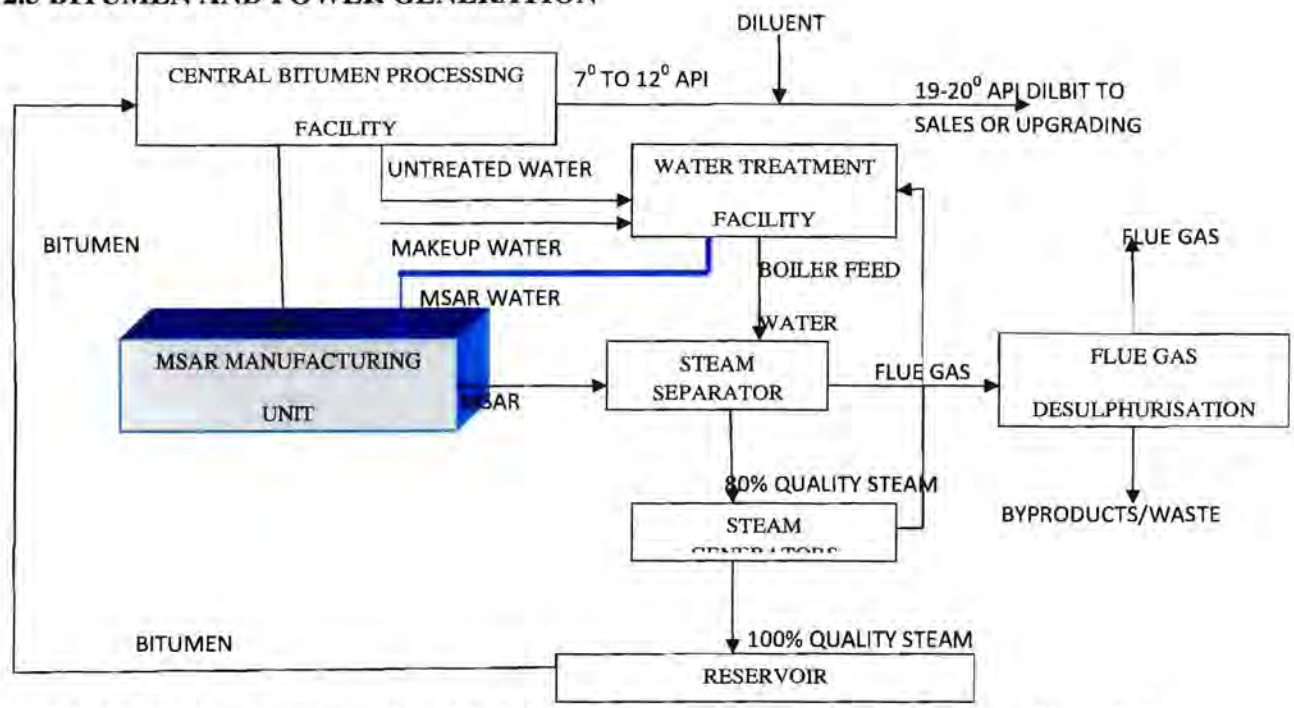

Fig 14: SAGD flow diagram with an MSAR manufacturing plant (CHOA conference Nov., 2004)

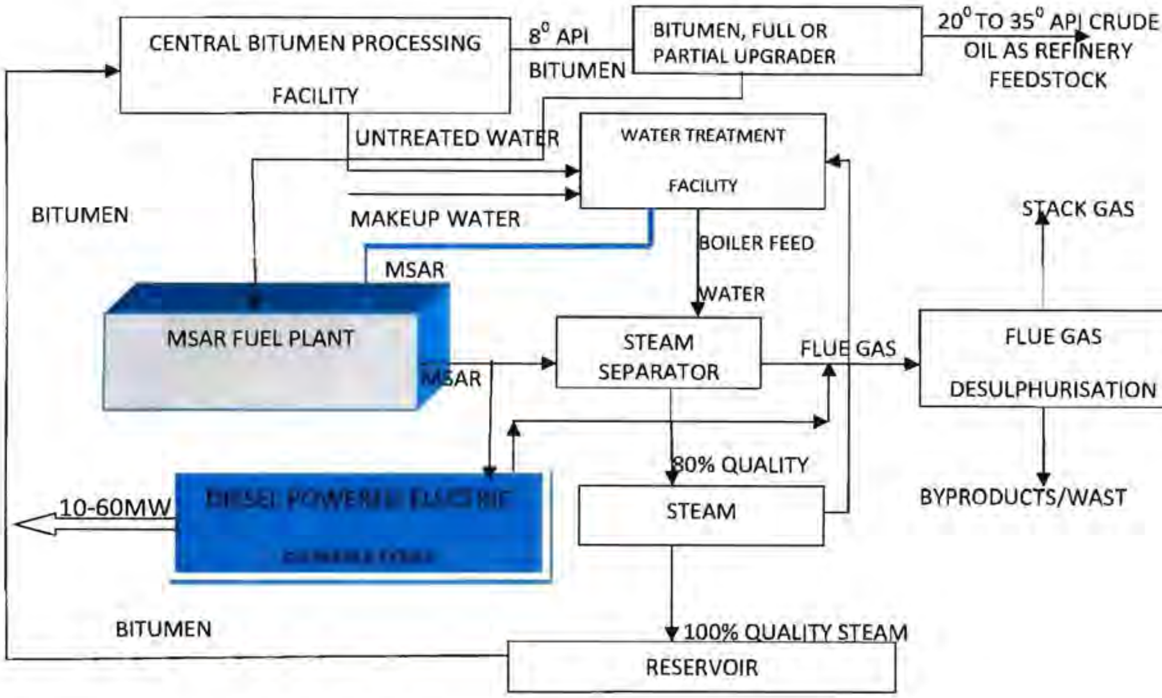

Figure 15: SAGD Project with power generation (AIHA Synergy Luncheon, March 2005)

The two flow diagrams above were presented by Quadrise Canada Fuel Systems Inc.(QFI) to substantiate the use of bitumen as fuel to generate steam and power for bitumen extraction, processing and upgrading.

QFI operates utilising technology owned by Akzo Nobel Sweden/Netherlands; the world's leader in surface chemistry. Use of Akzo Nobel's expertise ensures QFI are able to produce cost competitive and stable emulsified fuels suited to varying parameters of transportation, storage and application from virtually any residue or heavy crude feedstock.

QFI operates in a co-operative alliance format with Akzo Nobel, Netherlands, with regular exchange of commercial and marketing information and joint development of specific projects for MSAR production.

MSAR (Multiphase Superfine Atomised Residue) is a liquid fuel to replace natural gas in bitumen extraction process. It contains "very fine oil droplets in water suspension with low apparent viscosity. Many wide range of hydrocarbon feedstock (-10^0 to 14^0 API gravity) can be used. The fuel has combustion characteristics of 99.99% carbon burnout and short combustion residence time similar to that of natural gas". However, it has to be stored at ambient temperature. (www.quadrisecanada.com)

According to CHOA 2004, test results on MSAR revealed the following:

- Simple manufacturing of bitumen into MSAR and verified operational ease of burning MSAR

- Confirmed clean burn and 99.99% carbon burnout with radiant heat transfer 20% greater than natural gas
- Stable flame with minimum warm air and low pressure atomisation – steam not necessary
- Minimal re-heating of MSAR is required. MSAR offers reduced thermal NO_x vs. burning bitumen or residue.
- Savings of C$30million/year can be made using MSAR made from bitumen for plant consuming 30mmcf/d. (Quadrise2004, www.deercreekenergy.com)

Table 2: MSAR v/s Natural gas and Bitumen adapted from Quadrise Canada Fuel Systems Inc. 2004)

	MSAR vs. Natural gas	MSAR vs. Bitumen
1	MSAR cost can be substantially less than current natural gas price	Incomplete bitumen burnout, lower thermal efficiency boiler cleanouts, redundant boilers
2	Allows for long-term fixed fuel pricing	No steam atomisation required for MSAR
3	Fuel savings can motivate projects to proceed or enhanced economics	Bitumen preheating to 175°C
4	Insufficient natural gas supply for SAGD or power generation applications in future	Bitumen production not reduced by steam atomisation and pre-heating requirements
5	Preserve natural gas supply for domestic use	MSAR produces lower NO_x and particulates emission. Easier to handle and stored.

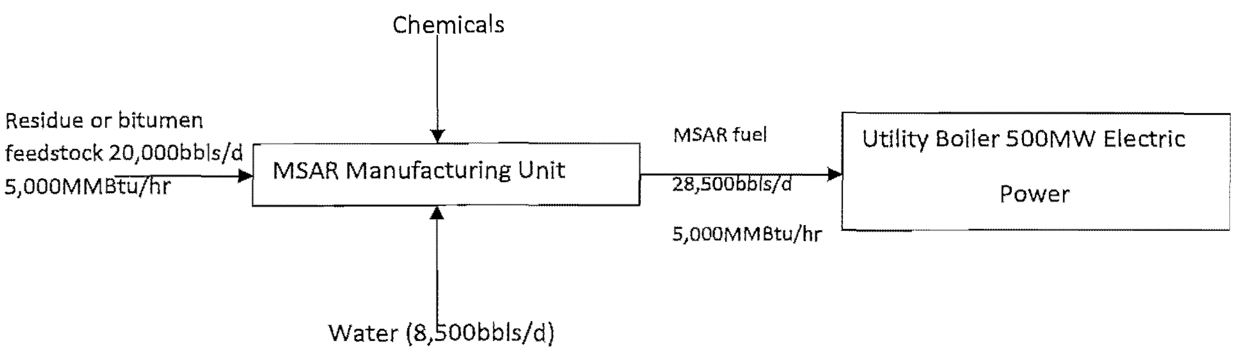

Figure 16: MSAR base model (AIHA Synergy Luncheon 2005)

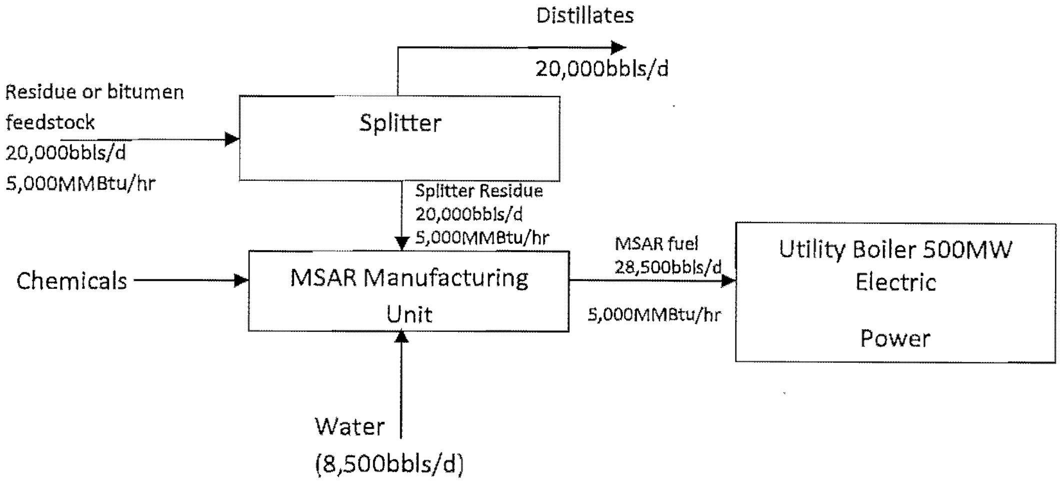

Figure 17: MSAR Splitter Model (CHOA Conference Quadrise 2004)

2.5.1 INDUSTRIAL APPLICATIONS

Industrial application of MSAR includes steam generation for boilers and furnaces in "alumina refineries, chemical plants and pulp mills; power for boilers and diesel engines in Independent power projects and Utility power generation; heat in kilns for alumina, lime, cement, pulp and paper plants".

CES (Clean Energy Systems) has "successfully tested its oxy fuel combustor on a combination of oil/water emulsion and natural gas. MSAR emulsion was co-combusted with natural gas to produce a steam/CO_2 product gas that was then used to drive a turbine to produce power. The first time that MSAR has been used to produce electricity, CES reported that the tests demonstrated, MSAR, when used in an oxy fuel combustion process, "has superior combustion characteristics as a low-cost liquid fuel."(Energy Resource Feb., 2007)

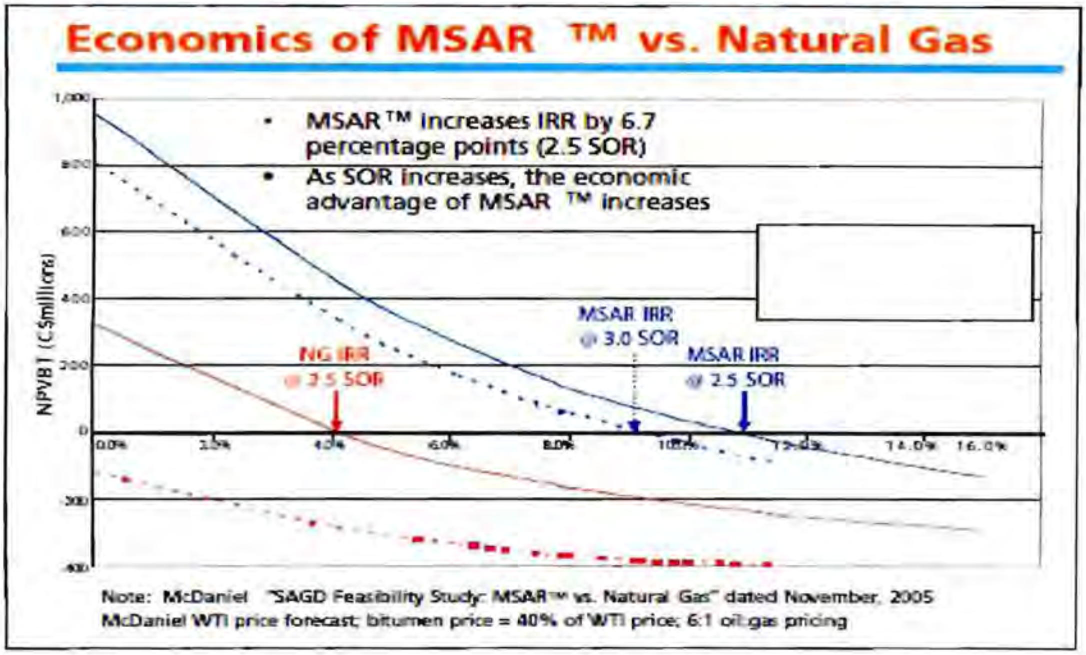

Figure 18: Economics of MSAR/Natural gas: Oil Sands Review.com September, 2006

The chart above shows that at higher SOR (steam to oil ratio), the economic advantage of MSAR is noticeable. The internal rate of return (IRR) could increase by as much as 6.7% at 2.5 SOR.

The economic advantage of MSAR over natural gas and heavy oil in the recovery of bitumen as enumerated by the authors above seems enormous based on field tests conducted so far. The use of MSAR is built into the economic model in chapter four.

2.6 INTEGRATED OIL SAND STRATEGY

This is a situation where a producer refines his/her own heavy crude. According to Collin Cook (2002), SAGD recovers more bitumen in place (OOIP) than any other in situ method. "The efficiency of the process versus CSS is in the lower steam/oil ratio and low pressure steam injection for SAGD. With steam/oil ratio being the cost drivers then SAGD is expected to have significant better production costs than CSS"

With the promising outlook of SAGD technology, the supply of synthetic crude to the world oil market could double within the next eight years. The mix in heavy crude is also getting heavier as the decline in conventional heavy crude is offset by heavier bitumen production.

Petro-Canada made some assumptions on the supply and demand of heavy crudes to the world market, and reported that despite the fact that refiners are having increasing ability to run heavy crude," the balance suggest that heavy crudes will have to penetrate new markets if the level of production promised by SAGD is to be brought on stream" This could lead to a bigger difference between the price of light and synthetic crude. Based on the foregoing therefore, "an integrated solution, which guarantees the producer's bitumen production an economic home removes a significant degree of risk and price volatility" (Colin Cook 2002)

The trend in the pricing of heavy oil over the years has been unstable and this may not change. According to Colin Cook 2002, "When heavy oil production exceeds demand, the light/heavy differential widens which is to say the price of bitumen falls. This forces the highest cost producer to shut in until the market stabilises"

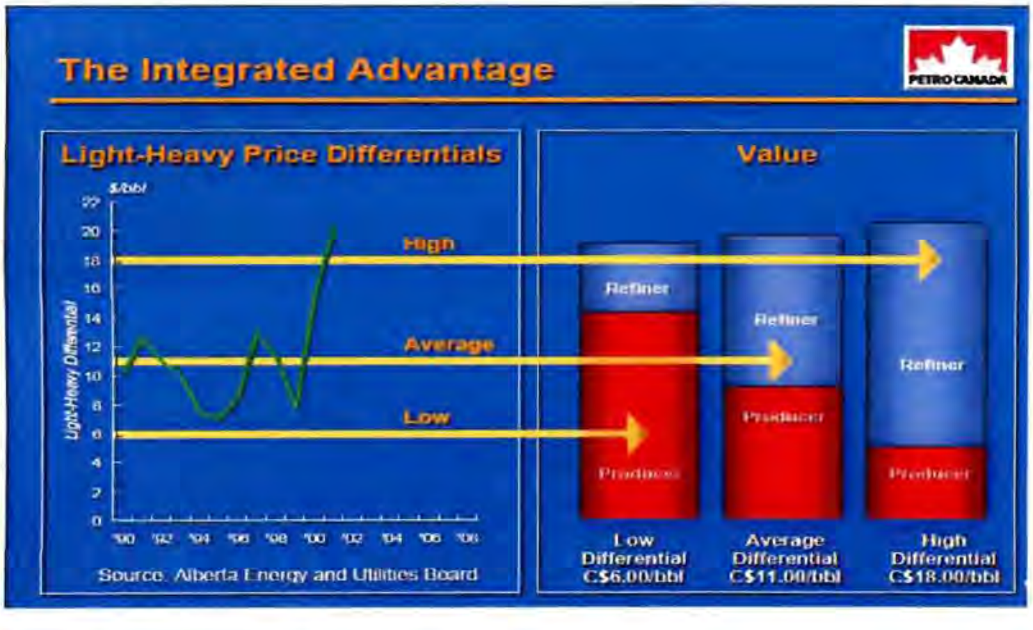

Figure 19: Source: C. Cook 2002: Integrated Oil Sand Strategy

Based on the chart above, what is accruable to the bitumen producer falls with higher light/heavy price difference while the refiners make more money. The converse of this scenario is also true. The result of an integrated oil sand development is a more stable earnings and cash flow performance.

The above scenario captured by the author is a key factor in suggesting an Integrated Oil Sand Strategy for the development of the Nigeria tar sand. It is more beneficial to produce ones own syncrude and refine same. The Asphalt unit of the Kaduna refinery has been out of service since 1986. An integrated oil sand strategy will provide the country the needed asphalt for her road constructions. This work by Colin Cook will be built into the economic model in chapter four of this dissertation

2.7 BITUMEN RECOVERY AND ECONOMIC EVALUATION MODELS

Some recovery models available today includes the eclipse finite difference simulation model developed by Schlumberger (www.slb.com/sis), the Lindrian equation (www.osumcorp.com/elements/usersfiles/..../CICP 2009-67 Papers.pdf), the artificial neutral network model (ANN) quoted in the Journal of Environmental Engineering and Science (http://rparticle.web-p.cisti.nrc.ca/) and the petroleum technology alliance technology Canada recovery model (PTAC) (www.ptac.org), etc. These models allow the researcher to predict the production rate/volume of bitumen/hydrocarbon, the recovery means and the best strategies for reservoir management from a given reservoir. Economic evaluation tools include but not limited to life cycle costing, differential/simplex equation methods etc

This chapter reviewed available literature on the availability of bitumen in Nigeria, the geology of the Athabasca oil sand deposit and the proven technologies available for bitumen recovery.

In the next chapter, a comparative analysis of the Nigeria and Athabasca oil and tar sands deposit will be undertaken by means of case study. This will also take into account all the cost elements using one of the recovery models and an economic analysis tool.

CHAPTER 3: RESEARCH METHODOLOGY

3.0 RESEACH PURPOSE.

According to Yin (1994), research is categorised into three main groups; exploratory, explanatory and descriptive. The purpose of exploratory research according to Denscombe (2000) is to gather as much information as possible througph the use of different sources. Yin (1994) added that it should also state a purpose and the criteria to judge the exploration successful. Yin (1994) said explanatory research explains the causal relationship between cause and effect. He further added that the aim of exploratory research is to develop a theory in order to explain the empirical generalisation developed at the descriptive stage. Descriptive research on the other hand, according to Foster (1998) is performed when studying a problem area with already existing theories or information. The goal of which is to develop a careful description of the different patterns suspected in the exploratory research.

Based on the above, this research is defined as being mainly descriptive, however it will be exploratory and to some extent explanatory.

3.1 RESEARCH APPROACH

Denscombe (2000) suggested that research follows two general approaches, quantitative and qualitative approaches. Foster (1998) explains that qualitative approach emphasises "processes and meanings that are not rigorously examined or measured in terms of quantity, intensity, amount or frequency" (www.design.ntnu.no) It is based on words. On the other hand, according to Bryman (2001), quantitative approach measures data, units, intensity, frequencies amounts and quantities. It deals with discrete data. Exploratory approach, according to Eriksson and Wiedersheim-Paul (2001) analyse cause-effect relationships. It explains what causes produce what symptoms. Miles and Huberman (1994) stated that it concerns the activities of making complex issues understandable exposing the interconnectivity of component parts with theory.

This dissertation is exploratory and quantitative in parts and somewhat explanatory in some parts.

3.2 DATA COLLECTION.

According to Yin (1994), there are six sources of data for research. These sources are interviews, documentation, archival records, direct observations, participants' observations and physical artefacts. For this dissertation however, archival records, documentations (scientific journals, open literature) are applicable.

3.3 CASE STUDY

Yin (1994) states that a case study is suitable to answer how and why questions and focuses on contemporary events and does not require control over behavioural events. In addition, Eriksson and Wiedersheim-Paul (2001) highlight that a case study involves the investigation of few entities but many variables, which gives an in-depth situation picture. Because this research question starts with an inherent "why", a multiple case study is the most appropriate research strategy for this dissertation.

A comparative analysis of the Athabasca (Grosmont and Nsiku) and Nigeria bitumen (elemental and chromatographic, physio-chemical and liquid properties, the techno-economics of bitumen) is carried out. The techno-economics data of bitumen as explored in Athabasca (Grosmont formation), Canada were obtained (vis-à-vis unit production, operating and refining costs as a function of the technology employed). The physio-chemical, elemental, chromatographic and liquid products properties of the Athabasca tar sands (Grosmont formation) were sourced from literature and engineering journals. This was done so as to juxtapose these properties and form the basis for prediction of the best extraction technology for the Nigeria tar sand.

These properties are also part of the parameters fed into the recovery model (especially the porosity, steam oil ratio (SOR)) e.t.c.

3.4 THE PTAC TECHNOLOGY RECOVERY MODEL

The PTAC technology recovery (Petroleum Technology Alliance Canada) model was developed for bitumen in carbonate formation and conventional oil reservoirs. The model allows the researcher to understand the trade-offs between recovery, energy, green house gases, water and costs that are implied in the choice of the recovery technology. The aim of the model is to maximise the total resource recovery, reduce overall energy intensity, green house gas emission intensity, reduce water intensity and above all reduce operating cost.

The model also allows for the process of applying recovery technologies one after the other in the same reservoir. The model is able to calculate the performance of the process technology and the status of the reservoir after the application of each of the technology. However, for the purpose of this dissertation, only the first process is considered.

The model was appraised by Lent Flint Phd, P.Eng of Lenef Consulting in February 2007 during a GHG emission reduction initiative in Denea and at ARCn during a technology information session. Two follow-up workshops were also held www.ptac.org/links/dl/BitumenRecoveryTechnology.pdf

Kambiz on April 30, 2007 appraised the model as an innovative approach that allows both Engineers and Researchers to better understand the trade off inherent in the choice of any recovery technology www.heavyoilinfo.com. He further reported that the model is based on the assumption that a reservoir will undergo multiple recovery mechanisms. That PTAC recovery model as an innovative idea is geared towards optimising recovery when primary oil recovery is no longer economical.

Bruce Peachey and Marc Godin also presented the model in February 2007 at a workshop at Encana Amphithearter in Calgary, Alberta as a follow-up to the workshops referred to above. The model was applauded as an innovation towards GHG reduction initiative.

The choice of the software for the techno-economic analysis for this dissertation was informed by the fact that it allows for an on the spot comparison of economic implication of the choice of a particular process technology in relation to another. An incorporation of green house gas emission requirement based on the Kyoto Accord into the model is also worthy of note. This is particularly interesting as Nigeria has been a signatory to the Kyoto accord since 1995 as part of the non-annex 1 economies. This means that the country was not committed to take action. However, the accord was adopted by the country in 1997 and ratified in 2004 (www.newswatchngr.com, www.KAS.com).

Parameters (steam generator, water source, electrical energy source and the reservoir type) are fed into the model and the unit cost is obtained as a function of that process technology.

The unit cost is thereafter used in the life cycle costing model.

3.4.1 MODEL KEY ASSUMPTIONS (adapted from www.ptac.org/)

The following assumptions were built into the model.

a) For the use of natural gas, the cost was taken to be CA$7.00 per GJ per energy content of fuel

b) For the use of bitumen as fuel, the cost was taken to be CA$3.88 per GJ per energy content of fuel [West Texas index (WTI)] = US$60 per barrel; bitumen = 40% WTI, US$ = 1.1 CA$ based on CAPP information.

c) For the use of heavy oil as fuel, the cost was taken to be CA$7.02 per GJ per energy content of fuel. (WTI = US$60 per barrel; bitumen = 40% WTI, US$ = 1.1 CA$)

d) If the electricity from the Alberta grid is used, the cost was taken to be CA$0.05 per kwhr.

e) Energy loss from the use of direct contact steam generator (DCSG) was taken to be 20%

f) If surface or ground water is used, the cost is CA$3.15 per m^3 and if it is saline aquifer the cost is CA$0.12 per m^3

g) Cost of purchase and emission of carbon dioxide was taken to be CA$15.00 per tonne each.

h) The cost of diesel was taken to be CA$25.43 per GJ ($1.00 per litre; 35GJ per m^3)

i) Recovery factors for SAGD, CSS, and ISC were taken to be 50%, 30% and 80% respectively

j) Makeup water requirement for CSS and SAGD as % of injected water volume was 20% (10% loss to formation and 10% to purging and disposal)

k) Natural gas used on lease (except for steam) was assumed to be 1.31GJ per m^3 of oil/bitumen produced (100% of gas oil ratio (GOR), 35GJ per m^3

l) Electrical energy required was taken to be 1.40 GJ per m^3 oil/bitumen produced (1,200 m^3 air per m^3 oil at 2MPa pressure

m) The cost of the user-defined-fuel (MSAR) was taken to be CA$5.50 per GJ (WTI = US$60 per barrel; bitumen = 40% WTI, US$ = 1.1 CA$)

The type of fuel used for bitumen recovery has a contributory effect on the GHG quality. The choice of this fuel is critical. In paragraph 2.5, MSAR was proposed as an alternative fuel for the Nigeria case. Its properties are outlined in paragraph 4.3.1 and table 7. The model provides for alternative fuel type by giving room for a user defined fuel (assumptions a-c)

On site cogeneration electricity is used for the Nigeria case as proposed in paragraph 2.5 and 2.5.1 while electricity from Alberta National grid is used for Grosmont. On site cogeneration also called combined heat and power (CHP) is a form of energy recycling process. Therefore assumption d differs. Assumption e is the same for both cases.

Assumption f differs as the cost of water differs between the two countries. See paragraph 4.3.1 and table 8, while assumptions g, h, i, j, k and l are the same for both cases.

Assumption m was adopted for the Nigeria case. It was suggested that the use of MSAR could reduce the operating cost of bitumen substantially increasing the IRR by as much as 6.7% at SOR of 2.5 and above. This will be verified in chapters 4 and 5.

3.5 TECHNO-ECONOMICS EVALUATION (FINANCIAL FIGURE OF MERITS)

A variety of figures of merits are used by energy policy analyst, investors, or developers to predict the cost effectiveness of a project. They often include capital cost, projected output, annual revenue, operating cost and deductions. For the purpose of this dissertation, however, these primary figures were identified.

3.5.1 NET PRESENT VALUE

Net present value is the all years' discounted after tax cash flow. Its usefulness is rooted in its recognition of the time value of money. Economic decisions in executing a project are made based on the value of the net present value. If the value is positive, then the decision to carry on with the project is a wise one. Mathematically,

$$NPV = \sum_{i=0}^{n} \frac{Bi}{(1+R)^{i}} - \sum_{i=0}^{n} \frac{Ci}{(1+R)^{i}}$$

NPV > 0, economic decision is appropriate.

Where B is the value of benefit (revenue); R is the discount rate, i is the time or period ranging from zero to n and C is cost.

3.5.2 INTERNAL RATE OF RETURN

It is defined as the discount rate at which the NPV is zero. The calculated IRR is examined to determine if it exceeds a minimally accepted return, called the hurdle rate. IRR becomes difficult to evaluate once one of the streams of discounted cost or benefit becomes negative giving rise to an n-order polynomial with composite root. No satisfactory way is available to avoid such polynomial ambiguity. In such circumstance, the use of NPV is recommended. Mathematically,

$$IRR = \left[\sum_{i-0}^{n} \frac{Bi}{(1+K)^{i}} - \sum_{i-0}^{n} \frac{Ci}{(1+K)^{i}} = 0\right] = 0$$

Where B is the value of benefit (revenue); R is the discount rate, i is the period ranging from zero to n and C is cost.

3.5.3 COST BENEFIT RATIO

This is the ratio of the present benefits (revenue) to present cost. It therefore means that a positive NPV will result in a B/C value that is greater than one, in which case the project is economical. Mathematically,

$$\text{B/C ratio} = \frac{\sum_{i=0}^{n} \frac{Bi}{(1+R)^{i}}}{\sum_{i=0}^{n} \frac{Ci}{(1+R)^{i}}}$$

B/C Ratio > 1, economic decision to carry on with the project is appropriate.

3.5.4 BREAK EVEN POINT

This is the point where the B/C ratio is one. It is also the point at which the NPV is zero.

3.5.5 ESCALATION

Escalation is regarded as changes in price levels occasioned by underlying economic conditions which could be external or internal. It reflects changes in price drivers such as productivity and technology as well as market conditions such as high demand, labour shortages, profit margin etc.

It may also be regarded as the provisioning in the cost estimate for equipment, materials and labour etc due to the continuing price changes over time. It is used to estimate the future cost of a project to bring the historical costs to the present.

Escalation could be predictive or historical. Predictive escalations are obtained from commercial forecasting services. It is expressed as the ration of the future value to the current value expressed as a decimal. Historical escalation on the other hand is the ratio of costs of an item or commodity at two different points in time (say year 2000 versus 2004) expressed as a percentage and if expressed as a decimal, it is the escalation index.

For the purpose of this dissertation, both predictive and historic escalation shall apply.

3.6 LIFE CYCLE COSTING

Life cycle costing estimates the revenue and expenses of a project or product over its expected life. Emphasis is placed on pricing products to cover all costs, not just production cost. The International

Electro-technical Commission Standard (IEC 60300) 2004 covers how life cycle costing is to be carried out.

According to Tiffany Bradford (2008), "Life Cycle Costing offers a different way to look at the overall cost of a product. It is closely related to Value Engineering" (www.accounting.siute101.com/) The beauty of life cycle costing is the fact that some cost elements of the project in its early life are captured before production phase where the bulk of the cost goes.

Some of the benefits are:-

(a) All costs associated with the project are visible

(b) It allows for business function relationships analysis

(c) Differences in early stage expenditures are highlighted allowing for accurate revenue prediction.

For the purpose of this dissertation, life cycle costing software version 1.9 (September 2006) by Paul Barringer (available from www.barringer1.com) was used to evaluate the cost elements of the recovery of bitumen from tar sand in Nigeria. The cost elements involved were fed into the model to calculate the NPV and the cash flow profile for three process technologies identified in the literature review. A trade off is thereafter done based on the results generated by the model.

3.6.1 MODEL ASSUMPTIONS

a) Project life cycle was taken to be 10years

b) A discounted rate of 12% was assumed consistent with the present rate in Nigeria.

c) A corporate tax rate of 23% was used in line with what is obtainable in the country.

d) The exchange rate was assumed to be CA$1.1 to US$1 and N120.00 to US$1

e) Maintenance and insurance costs were taken to be 2% of initial investment cost with an incremental factor of 12% per annum consistent with inflation rate in the country over the last five years. Operating cost increases also at the rate of 12% per annum. Maintenance cost starts at the beginning of the third year.

f) It is assumed that the refinery will be working at 80% installed capacity for 365 days a year.

g) It is assumed that 80% of the asphaltenes content of the Nigeria bitumen is recoverable

h) The Nigeria bitumen asphaltenes content is between 17.9% and 29.7% giving an average value of 23.8% which is used in the model.

i) It is assumed that the price of crude will fluctuate between \$60 and \$65 per barrel for which the average will be \$62.50 per barrel

j) Income will only accrue from power generation at the beginning of the third year due to the time required to produce MSAR

k) Adjustment factors were factored into the estimates (acquisition and operating costs) to account for costing differences.

3.6.2 FACTS USED IN THE LCC MODEL

a) The following petroleum products technical data/pricing were used consistent the current product price regime in the country. The conversion factor from barrels to tonne is adapted from http://www.nigerdeltacongress.com/marticles/mechanics_dynamics_feul.........

1) For premium motor spirit (PMS), 8.4998 barrels equals one metric tonne @ N65/litre

2) For liquefied petroleum gas (LPG), 11.6482 barrels equal one metric tonne @ N184, 000/tonne

3) For dual purpose kerosene (DPK), 7.765 barrels equals one metric tonne @ N75/litre

4) For automotive gas oil (AGO), 7.2296 barrels equals one metric tonne @ N100/litre

5) For automotive turbine kerosene (ATK), 7.765 barrels equal one metric tonne @ N100/litre

6) For Residual fuel oil, 6.208 barrels equals one metric tonne @ NN100/litre

3.7 SENSITIVITY ANALYSIS

Sensitivity analysis assists in gaining insight into variable(s) that is/are critical in the economic analysis model. The process involves changing the values of the input data in the model to see the effect on the output value. This could be done by way of model analyser using what- if – analysis table (data table format), multi-goal seeker or multi scenarios in excel work-sheet. Data fed into the economic evaluation model will be subjected to sensitivity analysis using one of the tools mentioned above.

CHAPTER SUMMARY

This explained the methodology used in this dissertation. The chapter presented and motivated how the data were collected in order to find answers to the research question so as to fulfil the purpose of this dissertation. In the next chapter, results of findings of this dissertation will be documented.

4.0 CHAPTER 4: RESULT OF FINDINGS

This chapter documents the results of the finding of this dissertation.

4.1 COMPARATIVE ANALYSIS OF THE NIGERIA AND ATHABASCA OIL AND TAR SANDS

Comparative analysis of the Athabasca and Nigeria tar sands was considered to look at their similarities and differences. The resin concentration and its effect on the quality of tar sand, the viscosities of the two sands and the consequence of this on recovery and energy usage, reservoir properties and their effects on recovery, process technology adaptation and the environment, the age and the environment of the formations were all considered. The relationship between the asphaltenes content, conradson/ramsbottom carbon residue and yield volume during hydro-cracking was also considered. The analysis also looked at the liquid product properties and thermal efficiency of the products from the two tar sand sources. The analysis is done under the following subheadings;

(a)The Geology

(b) Elemental and chromatographic analysis

(c) Thermal and liquid products properties.

4.1.1 GEOLOGY

4.1.1.1 ATHABASCA

During the literature review, the work done by some authors were consulted. The survey revealed the following:

Athabasca oil sand according to the AUEB (2003) is divided into three formations; the Athabasca, McMurray and Cold lake formations. The Athabasca deposit bed according to Penberton (1982) is fluvial in nature and contains brackish water assemblage. The heterolithic stratification was interpreted as tidally influenced deposition.

Carrigy (1959) wrote that the McMurray formation sits "on an angular unconformity that truncates the Devonian strata".

(http://www.cseg.ca/conventions/abstracts/2004/2004abstracts/122S0227-Gingras_M_heavy_oil_bitumen_oil_sands.pdf) He further stated that the formation occurs in incised valley formed by fluvial processes and marine marginal transgression in the earlier Cretaceous sea level rise.

The cold lake division according to Taylor (1990) includes stacked distributaries mouth bar sequences and McCrimmon and Arnortt (2002) said it also includes non-marine fluvial and highly energy tidal sand flats deposits. According to Pemberton (1992), "the Upper Grand Rapids represents largely brackish water near shore deposition overlying more conditions of lower Grand Rapids and upper clear water". (CSEG2004) Ranger and Calpin (2003) reported that the McMurray strata are shallow, low energy shore-faceies deposit and small deltaic complex.

4.1.1.2 NIGERIA

According to Raymant (1965) and Adegoke (1969), the Nigeria tar sand is divided into (two formations) Araromi informal formation and the Abeokuta formation. Bilman (1976) divided it into three formations; The Nkporo shale, Abeokuta formation and the Albian sand. Omatsola and Adegoke (1981) divided the formation into (Three) Araromi, Afowo and Ise formation. These formations occur in Upper cretaceous – Palaeocene to middle-late cretaceous to Neocomian.

The stratigraphic column by Energy Porfolios Manager (2004) for MSMD identifies three divisions of the Nigeria bitumen deposit; Araromi (Abeokuta formation), Afowo (Turonian/Albian sand) and the Ise formation in that order. The ages are Maastrichtian, Campanian-Aptian and Barremian- Neocomian respectively in the cretaceous period.

According to the report by the Ministry of Solid Minerals Development (MSMD), the occurrence of grey coloured clays in the sediments has been considered to be strictly formed in wet environment indicative of marine facies. Hallman (1964) related black shale as indicative of deep water deposits adjacent to hyper-saline water conditions for alteration of shale and limestone horizon.

The MSMD report also suggested the tectonic features were built up during the period of intense taphrogenic tectonism between Neocomian and Albian times. Sand: Shale ratio ranges from 80:20 in the lower cretaceous under fluvial to deltaic conditions. In the lower senonian, depositional environment conditions became more marine raging from littoral to neritic and giving rise to a sand/shale ratio of 10: 90.

4.1.2. ELEMENTAL AND CHROMATOGRAPHIC ANALYSIS.

To properly compare the Nigeria and Athabasca bitumen, a comparative analysis of samples from these sources is necessary. The analysis looked at the following properties of the ore as shown in the table below.

The data was sourced from available literature and from the Ministry of Solid Minerals Development, Abuja.

Table 3: Comparative Analysis of the Elemental and Chromatographic Analysis of the Nigeria and Athabasca Oil and Tar Sands adapted from Prof. E.A Fayose 2004: Bitumen in Ondo State and the Ministry of Solid Minerals Development, Abuja

Nigeria Sample A								
	% Whole Bitumen	% C	% H	%N	%O	% S	Mol. Wt	C/H Atomic Ratio
Benzene Insoluble	0	77.79	8.49	1.95	7.71	2.5	686	0.76
Resin I	34.2	88.89	9.94	0.62	3.72	1.41	644	0.71
Resin II	9.00	80.40	10.16	0.72	7.48	0.99	954	0.66
Aromatics	12.40	88.78	10.80	0.11	0.65	0.62	412	0.68
Saturates	22.20	85.96	12.55	0.04	0.55	0.00	352	0.56
Asphaltenes	23.20	84.62	8.59	1.25	3.19	1.08	4436	0.82
Whole Bitumen	0.00	86.02	10.43	0.65	1.76	1.32	667	0.69
Nigeria Sample B								
Benzene Insoluble	0	74.03	8.60	2.15	9.33	2.33	539	0.72
Resin I	33.20	81.85	9.86	0.65	4.59	1.24	560	0.69
Resin II	11.60	82.07	10.14	0.87	5.90	1.15	847	0.67
Aromatics	12.90	88.91	10.75	0.05	0.45	0.72	412	0.69
Saturates	22.33	86.40	12.86	0.04	0.72	0	363	0.56
Asphaltenes	21.30	85.14	8.68	1.29	2.70	1.17	6173	0.82
Whole Bitumen	0	86.67	10.44	0.67	1.78	1.11	640	0.69
Athabasca Sample								
Benzene Insoluble	0.00	74.81	8.35	1.25	7.36	5.89	N/A	0.75
Resin I	36.70	81.21	9.54	0.51	2.66	6.01	737	0.71
Resin II	5.50	79.70	9.79	0.87	4.61	4.80	946	0.68
Aromatics	19.30	85.11	10.20	0.00	0.17	4.39	347	0.70
Saturates	22.50	86.43	13.35	0.00	0.00	0.00	332	0.54
Asphaltenes	18.20	80.50	8.13	1.11	1.84	7.82	7171	0.83
Whole Bitumen	0.00	82.96	10.26	0.50	1.21	4.64	544	0.67

Chromatographic analysis of the Nigeria sample in terms of carbon/hydrogen atomic ratio and the elemental composition of bitumen and asphaltenes yielded average value for carbon to be 84.90, hydrogen to be 8.7, sulphur to be 4.2, oxygen and nitrogen 1.4. The asphaltenes content ranges between

21.30% and 23.20%. The ratios of the components are indications that about 60% of the tar sand contains naphthenic and aromatic hydrocarbon. These components are feedstock for large scale manufacturing of lubricating oils and reformats for the petrochemical industries (http://msmd.gov.ng/Bitumen%20Bid%20Memo.pdf)

Asphaltenes is the residue left behind after the hydrocarbon constituent of the ore has been removed. This residue is not a waste as this could be used to produce MSAR to generate power and also used in road construction.

It could also be noticed that the Nigeria tar sand contains a high concentration of resin. This would make the Nigeria bitumen more acidic and so some of the processing units would require specific design modification. The Nigeria bitumen contains more asphaltenes but lower in aromatic than Athabascan's. Also the Nigeria sample is higher in carbon, hydrogen and oxygen but obviously lower in Sulphur and other heavy metals. This quality gives the Nigeria bitumen edges over that of Athabasca since these impurities, as they are called, are undesirable in petroleum products.

4.1.3 PHYSIO-CHEMICAL, LIQUID PRODUCT AND THERMAL PROPERTIES.

Table 4: Comparative table of the Physio-Chemical, Liquid Product, and Thermal Properties of Athabasca and Nigeria Oil and Tar Sands (Adapted from Bitumen Bid Memo 2004; Ministry of Solid Mineral Development Abuja

	Physio-Chemical Properties		Liquid Product Properties Non- catalytic		Liquid Product Properties Catalytic	
	Nigeria	Canada	Nigeria	Canada	Nigeria	Canada
API	5-11	6-9	24	15	27	20
Viscosity at 100F CS	300,000	40,000	40	N/A	40	N/A
Sulphur, %Wt	1.0-2.5	4.0-5.5	0.61	4.50	0.40	2.30
Asphaltenes, % Wt	14-27	16-23	4.40	5.00	0.40	7.00
Conradson Carbon Residue (%CCR)	20	24	3.00	N/A	3.00	N/A
Sulphur in coke %Wt	N/A	N/A	1.00	2.50	0.80	2.50

Thermal Properties				
	Ramsbottom carbon wt%	Asphaltenes Wt%	Heat of Combustion BTU/BL	Heat of Combustion KJ/KG
Nigeria Sample A	10.20	23.20	18,200	42,300
Nigeria Sample B	9.30	21.30	18,200	42,300
Athabasca	12.10	18.20	17,900	41,700

As explained above the Nigeria bitumen has higher asphaltenes content, however table 4 clearly demonstrates that the high content does not give rise to higher ramsbottom/conradson carbon residue value as displayed above. When hydrocarbon containing substance burns in air, the substance leaves behind a residue called coke. The left over is measured as a weight percentage of the original substance (ore). This is an indication of higher yield of product volume during hydro-cracking. The liquid products also indicated low sulphur content. However, from the table, the Nigeria samples possess higher viscosity than the Athabasca sample. Viscosity is one property of bitumen that must be overcome in order to have a good yield. Therefore, more energy will be required to lower the viscosity of the Nigeria bitumen in the reservoir for it to flow to the surface and to maintain the required viscosity during piping to the refinery.

Heat of combustion is the amount of energy produced when one mole of the substance burns in air. As shown in the table above, the Nigeria samples have higher heat of combustion than the Athabasca sample (with 600KJ/KG) which is an indication that liquid products from the Nigeria oil sand will be more efficient fuel than those from Athabasca.

4.2 RESERVOIR PROPERTIES

Table: 5 "Calculated parameters for the Nigeria Oil and tar Sands" (Adapted from Professor E.A Fayose: Bitumen in Ondo State; Prospects and Promises)

Sample No	Bit. Sat'n (Wt %)	App. Ø (Wt %)	Pore Bit Sat'n (Wt %)	Pore Water Sat'n (Wt %)	Dry Weight (%)
1	10.75	28.58	82.58	17.42	11
2	11.26	27.64	89.61	10.39	11.41
3	10.95	27.21	89.07	10.93	11.05
4	10.96	27.51	87.27	12.73	11.14
5	11.06	27.9	87.47	12.78	11.25
6	11.06	28.02	87.75	12.25	11.34
7	12.71	31.37	86.94	13.06	12.96
8	14.22	34.39	86.68	13.32	14.54
9	11.11	27.66	86.68	11.34	12.27
10	12.12	29.66	90.85	9.15	12.38
11	8.18	29.33	77.08	22.82	8.38
12	5.93	22.24	60.91	39.09	6.17

The table above display the bitumen and pore-bitumen saturation necessary to predict the recovery rate of the Nigerian bitumen. The average pore bitumen saturation and approximate porosity are 85% and 27.98% respectively.

From the above, it is certain that the Nigeria and Athabasca oil sand have many common properties (Chemical and Physical) than dissimilarities. This is clearly indicated in the reservoir data used in the PTAC technology recovery model simulation below.

Table 6: Comparison of reservoir properties of the Nigeria and Athabasca (Grosmont formation) oil/tar sand

Properties	Nigeria	Athabasca (Grosmont formation
Porosity	27.98%	20%
Temperature	$26.50^{0}C$	$10^{0}C$
Oil saturation	85%	79%
Reservoir pressure	2.5 MPa	1.03 MPa

Having identified the similarities and differences between the Nigeria and Athabasca tar sand as shown above, it is therefore possible to transfer process technology from Canada to Nigeria albeit with little modification to accommodate some of the minor differences. These modifications are built into the recovery model in the form of user defined data.

4.3 BITUMEN PROCESS TECHNOLOGY RECOVERY MODEL

The recovery model was adapted from the PTAC recovery model by Petroleum Technology Alliance Canada (available from www.ptac.org/). The software is declared free for use although, for information purpose only. Most of the data used in the software according to the authors, followed from ten years of intensive research. The data below were fed into the model as user defined data based on information obtained from literature survey and from the model itself. Three process technologies (CSS, SAGD and ISC) were tested using the model to obtain the unit cost of processed bitumen as a function of the process technology. The input and output data are as shown in the tables below.

4.3.1 USER DEFINED IMPUT DATA

Table 7: User defined fuel (MSAR)

Parameters	Units	Default value for natural gas	Calculated value	Source
Energy content per volume	GJ/m^3	0.0374	0.04488	20%>Natural gas (www.quadrisecanada.com)
Density	Kg/m^3	900	900	MSMD, Bitumen bid memo (2004)
Water content in combustion gases	Kg H_2O/Kg Fuel	0.002	0.002	Calculation
CO_2 emission from combustion (per mass Fuel)	$KgCO_2$/Kg Fuel	2.75	1.54	44%< natural gas (www.quadrisecanada.com)
CO_2 emission from combustion (per energy cost)	$KgCO_2$/GJ of Fuel	49.63	27.44	44%< Natural gas (www.quadrisecanada.com)

In simulating the model for the Nigeria tar sand, user defined data are required. In calculating these data, the default values for natural gas are used. The parameters for fuel are as defined in the table above. Comparing MSAR and natural gas as discussed in paragraph 2.5, the values in column 4 in the table were obtained

Table 8: User defined electricity (On site cogeneration with MSAR) and water source.

Parameters	Units	Default value for natural gas	Calculated value	Source
CO2 emission	$KgCO_2/MWh$	250	140	44%< natural gas (www.quadrisecanada.com)
Cost	CA$ per KWh	0.05	0.05	National Electricity Board (PHCN) at ₦6.00 per KWh with exchange rate of N120 to US$1.00 (2008 value)
Water creates demand on fresh water source	Yes =1, No = 0	1	1	
Cost of water	CA$ per m^3		$2.29	Ministry of Water Resources, SN250.00/1000litres, exchange rate at N120.00 to US$1.00 (2008 value)

Table 9: Reservoir properties of the Nigeria tar sand available from (http://msmd.gov.ng/Bitumen%20Bid%20Memo.pdf)

Parameters	Unit	Value	Source
Average Depth	M	200	Bitumen Bid Memo 2006. MSMD2004.
Average Porosity	%	27.98	Bitumen Bid Memo 2006. MSMD2004.
Average Pressure	MPa	2.30	Bitumen Bid Memo 2006. MSMD2004.
Average temperature	°C	26.5	Bitumen Bid Memo 2006. MSMD2004
Average oil saturation	%Volume	85	Bitumen Bid Memo 2006. MSMD2004.

Table 7, 8 and 9 outlined the parameters necessary to simulate the recovery model. Worthy of note is the cost placed on carbon dioxide emission in accordance with the Kyoto accord.

4.4 OUTPUT DATA

Upon simulation the following data were generated for each of the three process technologies tested for the Nigeria tar sand. The results are as shown in the tables below.

Table 10: Steam assisted gravity drainage

SELECTION OF MODEL OPTION		PRESENTATION OF GHG AND RECOVERY SUMMARY		
Option name	Option Selection	Parameters	Units	Value
Reservoir Name	User Defined	Reservoir	N/A	User Defined
Process	SAGD	Process Name	N/A	SAGD
Steam generator	DCSG	Recovery	% OOIP	50%
Make up water source	User defined surface/underground	Cumulative Recovery	% OOIP	50%
		Total Energy Intensity	GJ/m^3 of oil/bit. Produced	7.13
Fuel	User defined (MSAR)	Total fresh water intensity	m^3 H_2O of oil/bit. Produced	0.25
Electricity Source	User defined on site cogeneration (MSAR)	Total GHG intensity	Kg CO_2 of oil/bit. Produced	187
		Total operating cost	$CA\$/m^3$ of oil/bit. Produced	$40.59

Table 11: Cyclic steam stimulation

SELECTION OF MODEL OPTION		PRESENTATION OF GHG AND RECOVERY SUMMARY		
Option name	Option Selection	Parameters	Units	Value
Reservoir Name	User Defined	Reservoir	N/A	User Defined
Process	CSS	Process Name	N/A	CSS
Steam generator	DCSG	Recovery	% OOIP	30%
Make up water source	User defined surface/underground	Cumulative Recovery	% OOIP	30%
		Total Energy Intensity	GJ/m^3 of oil/bit. Produced	7.44
Fuel	User defined (MSAR)	Total fresh water intensity	m^3 H_2O of oil/bit. produced	0.45
Electricity Source	User defined on site cogeneration (MSAR)	Total GHG intensity	Kg CO_2 of oil/bit. Produced	190
		Total operating cost	$CA\$/m^3$ of oil/bit. Produced	$44.14

Table 12: In situ combustion

SELECTION OF MODEL OPTION		PRESENTATION OF GHG AND RECOVERY SUMMARY		
Option name	Option Selection	Parameters	Units	Value
Reservoir Name	User Defined	Reservoir	N/A	User Defined
Process	ISC	Process Name	N/A	ISC
Steam generator	N/A	Recovery	% OOIP	80%
Make up water source	N/A	Cumulative Recovery	% OOIP	80%
		Total Energy Intensity	GJ/m^3 of oil/bit. produced	2.71
Fuel	N/A	Total fresh water intensity	m^3 H_2O of oil/bit. produced	N/A
Electricity Source	User defined on site cogeneration (MSAR)	Total GHG intensity	Kg CO_2 of oil/bit. Produced	65
		Total operating cost	$CA\$/m^3$ of oil/bit. Produced	$25.00

Running the same model for Athabasca tar sand deposit (Grosmont formation), Canada, the following result is obtained

Table13: Steam assisted gravity drainage

SELECTION OF MODEL OPTION		PRESENTATION OF GHG AND RECOVERY SUMMARY		
Option name	Option Selection	Parameters	Units	Value
Reservoir Name	Grosmont formation	Reservoir	N/A	User Defined
Process	SAGD	Process Name	N/A	SAGD
Steam generator	DCSG	Recovery	% OOIP	50%
Make up water source	Fresh surface/underground	Cumulative Recovery	% OOIP	50%
		Total Energy Intensity	GJ/m^3 of oil/bit. Produced	7.13
Fuel	Natural gas	Total fresh water intensity	m^3 H_2O of oil/bit. Produced	0.25
Electricity Source	Alberta Grid	Total GHG intensity	Kg CO_2 of oil/bit. Produced	340
		Total operating cost	CA$/$m^3$ of oil/bit. Produced	$57.27

Table 14: Cyclic steam stimulation

SELECTION OF MODEL OPTION		PRESENTATION OF GHG AND RECOVERY SUMMARY		
Option name	Option Selection	Parameters	Units	Value
Reservoir Name	Grosmont formation	Reservoir	N/A	User Defined
Process	CSS	Process Name	N/A	CSS
Steam generator	DCSG	Recovery	% OOIP	30%
Make up water source	Fresh surface/underground	Cumulative Recovery	% OOIP	30%
		Total Energy Intensity	GJ/m^3 of oil/bit. Produced	7.44
Fuel	Natural gas	Total fresh water intensity	m^3 H_2O of oil/bit. produced	0.44
Electricity Source	Alberta grid	Total GHG intensity	Kg CO_2 of oil/bit. Produced	346
		Total operating cost	CA$/$m^3$ of oil/bit. Produced	$61.33

Table 15: In situ combustion

SELECTION OF MODEL OPTION		PRESENTATION OF GHG AND RECOVERY SUMMARY		
Option name	Option Selection	Parameters	Units	Value
Reservoir Name	Grosmont formation	Reservoir	N/A	User Defined
Process	ISC	Process Name	N/A	ISC
Steam generator	N/A	Recovery	% OOIP	80%
Make up water source	N/A	Cumulative Recovery	% OOIP	80%
		Total Energy Intensity	GJ/m^3 of oil/bit. produced	2.71
Fuel	N/A	Total fresh water intensity	m^3 H_2O of oil/bit. produced	N/A
Electricity Source	Alberta grid	Total GHG intensity	Kg CO_2 of oil/bit. Produced	65
		Total operating cost	CA$/m^3$ of oil/bit. Produced	$25.00

According to Duke du Plesis (2004), current production cost (operating and supply costs) of the Alberta Oil sands, Athabasca, Canada is as shown below.

Table 16: Current Production Cost: Source: Duke du Plesis (2004): Alberta oil sands resources production, growth, products and market.

		Cost/bbls ($CDN, 2003)	
Process	Product	Operating Cost	Supply Cost
SAGD	Bitumen	8-14	11-17
CSS	Bitumen	8-14	13-19
CHOP	Bitumen	6-9	12-16
ISC	Bitumen	4-10	14-18

Applying escalation to the quoted costs above using the predictive and historic escalation indices by IHS/CERA for downstream capital cost index using 2003 as the base year, an adjustment factor of 1.62 is obtained. The adjusted supply cost as shown in table 14 was obtained using the average of the supply cost range.

4.5 SUMMARY

Using the conversion factor of 1 m^3 equals 6.28994 barrels and US$1.00 equals CA$1.10 (www.exchagerate.com) and taking the average for the supply costs, the operating costs for the process technologies chosen above are as shown in the table below.

Table 17: Summary table

Process	Calculated production cost	Calculated Supply Cost	Calculated operating cost (production + supply cost)
SAGD	US$5.86	US$20.62	US$26.48
CSS	US$6.38	US$23.56	US$29.94
ISC	US$3.61	US$20.89	US$24.50

4.6 LIFE CYCLE COSTING MODEL

The life cycle of the process technologies above were tested using Paul Barringer life cycle costing (LCC) software (www.barringer1.com). The unit costs calculated above were fed into the model with some other cost elements necessary for the simulation. These other cost elements were sourced from literature and journals (Oil and gas Journals and websites of companies like Nexen, Suncor, Imperial, PetroCanada etc with experience in tar sand processing technologies)

The LCC software by Paul Baringer was validated in May 1998 at the National Petrochemical and Refiners Association Meeting. The software is available free from Paul Barringer but with an initial registration online with Barringer and Associates Inc. The last revision was September 2006.

Using the reserve estimate by Coker (1976), the recovery rates as used in the PTAC recovery model and the life span of the project (10 years), the recovery volumes by each of the process technologies were calculate.

In calculating the initial investment (acquisition cost) for each of the process technologies, the work by Singh Surindar, Du Plessis M.P, Isaacs E. E & Kerr Rich (2005) was used as a baseline. The acquisition cost for MSAR was also obtained from Energy Resources (2007). The cost of acquiring refinery was obtained from the work by Colin Cook (2004) and the Kaduna refinery in Nigeria was set as a baseline.

This was done because the Kaduna refinery is the only one in the country capable of refining crude from bitumen and heavy oil and so serves as prototype. The technical parameters of the refinery are as shown below

Table 18: Yield data of the Kaduna refinery adapted from Ministry of solid Minerals Development (2004) <http://msmd.gov.ng/Bitumen%20Bid%20Memo.pdf>

Products	% Yield (a)	Yield in tons (b)	Value/ton (₦) (c)	Total value (₦) (d)	Total value ($) (e)
LPG	1.02	34.47	184,000	6,342,480	52,854
PMS	27.70	914.05	87,845	80,294,722.25	699,122.69
DPK	13.31	405.15	92,600	37,516,890	312,640.75
Gas Oil	19.22	609.79	114,950	70,090,762.50	584,089.69
Fuel Oil	17.22	593.06	123,466	73,222,745.96	610,189.55
Base Oil	1.42	47.85	80,100	3,832,785	31,939.88
Bitumen	3.42	116.13	52,050	6,044,566.50	50,731.39
Wax	0.11	3.58	51,200	183,296	1,527.47
Petrochem (est)	0.23	45.8	110,000	5,038,000	41983.33
Refinery fuels	14.32	489.91	88,836.48	43,521,879.92	362,682.33
Loss	2.02	63.61	45,000	10,333,444.50	86,112.04

Column (e) in the table above gives a total of $2,833,872.15. In one year this will amount to $1,034,363,688.80. At 80% working efficiency, the annual yield of the refinery will amount to $827,490,951. (Quoted values (columns c, d, & e) are for 2008/2009)

These technical parameters were used to calculate the income from refining. The maintenance cost was taken to be 2% of the initial acquisition cost. The cost starts at the beginning of the 3rd year of the project.

The income from power generation starts at the beginning of the third year. A total of 250MW is to be produced and increased to 600MW within 3years. The Project is to utilise 300MW and the other half of 300WM to be sold. The income is calculated from the following:

1Kwh costs ₦6. 00 and US$1.00 equals ₦120. 000.

There are also sales from asphaltenes. The Ministry of Solid Minerals reported that the asphaltenes content of the Nigeria Bitumen is between 17.9% and 29.7% and at a recoverable rate of 80%, (http://msmd.gov.ng/Bitumen%20Bid%20Memo.pdf) the income from asphaltenes is thus calculated. The result from the simulation is presented in table 20 below.

Table 19: Input data into the life cycle costing simulation

Process	Acquisition cost		
	MSAR (1.072)	Refining (1.45)	Process (1.95)
SAGD	13,000,000	2,600,000,000	140,000,000
ISC	13,000,000	2,600,000,000	175,000,000
CSS	13,000,000	2,600,000,000	175,000,000

Applying adjustment factors above, the acquisition cost is as shown in table 20 below.

Table 20: Adjusted acquisition costs

Process	Acquisition cost		
	MSAR (US$)	Refining (US$)	Process (US$)
SAGD	13,936,000	3,770,000,000	210,000,000
ISC	13,936,000	3,770,000,000	341,250,000
CSS	13,936,000	3,770,000,000	341,250,000

Table 21: Operating and Maintenance costs with projected income from the project

Process	Operating cost (US$)	Maintenance cost (US$)	Income		
			Refining (US$)	Asphalt (US$)	Power (US$)
SAGD	850,537,600	79,878,720	827,490,951	422,378,000	2,340,000,000
CSS	936,672,800	82,503,720	827,490,951	253,456,000	2,340,000,000
ISC	786,940,000	82,503,720	827,490,951	540,667,200	2,340,000,000

Table 22: Summary result of the life cycle costing simulation

Processing technology	NPV	IRR
SAGD	US$3,062,544,012	36.35%
CSS	US$1,570,907,781	24.51%
ISC	US$3,502,515,167	39.64%

This chapter looked at the similarities and differences between the Nigeria and Athabasca tar sands (with particular reference to the Grosmont formation) by way of comparative analysis. The process technologies as used in Canada were evaluated with a view to adapting them to the Nigeria situation. The chapter evaluated the recovery technologies with a view to obtaining the unit cost of applying them and their life cycle costing so as to make an economic decision as to investment in the Nigeria oil sand exploration and exploitation.

In the next chapter, detailed explanation of the findings and their implications will be given. Inferences from this will also be drawn in line with the problem statement and the objectives of this dissertation.

CHAPTER 5: DISCUSSION AND INTERPRETATION

This chapter documents the explanation and interpretation appertaining to the findings of the comparative analysis and the results of the simulation in the previous chapter.

5.1 COMPARATIVE ANALYSIS.

As shown in the previous chapter, there are many similarities between the Nigeria and Athabasca bitumen both in their geology and physical/chemical properties. As pointed out in paragraph 4.1.1, the Athabasca and Nigeria tar sands are both divided into three formations and they both occur in marine environment under fluvial to deltaic condition in the upper cretaceous to Palaeocene between Neocomian and Albian times. It was also reported that the two deposits (Athabasca and Nigeria) sit on an angular unconformity in an incised valley.

This may account for the close similarities in the reservoir properties of the two tar sands. Once established, it will be possible to transfer process technology between the two countries (Nigeria and Canada).

With the elemental and chromatographic analysis, it is established that the Nigeria tar sand is more asphalthenic (with lower aromatic and sulphur content) giving rise to more hydro-cracking volume than its Athabasca counterpart due to its low conradson/ramsbottom carbon residue value.

However, the two tar sands have generally, wet sand grains, similar textural parameter, oil saturation and generally, similar chemical properties. Therefore, any of the process technologies used in Athabasca is adaptable to Nigeria.

5.2 UNIT (OPERATING) COST

The unit cost of a product is the amount it costs to produce one unit of that product. Unit cost here therefore denotes how much it will cost to produce one barrel of bitumen oil from oil or tar sand. Using the data set out in tables 6, 7 and 8, the recovery technology simulation software yielded the results in tables 9, 10 and 11. The supply costs were obtained from the source indicated in table 12.

Comparing the unit cost obtained above with that of Athabasca tar sand (the Grosmont formation) using the same model, the Nigeria tar sand has lesser unit cost of production as shown in the table below.

Table 23: Comparison of unit operating cost of Athabasca and Nigeria bitumen

Process	Reservoir Type (With Unit Cost CA$/m^3)		Difference (CA$/m^3)
	Grosmont(Athabasca)	Nigeria	
SAGD	57.27	40.59	16.68
CSS	61.33	44.14	17.19
ICS	25.00	25.00	NIL

The difference in unit operating cost amount to CA$16.68 for SAGD and CA$17.19 for CSS. The lower operating cost recorded for the Nigeria deposit could be as a result of the lower sulphur and higher asphaltenes content of the Nigeria tar sand that could give rise to higher hydrocracking volumes. Also in paragraph 4.2 above, it was recorded that the Nigeria tar sand has higher porosity and oil saturation rate than its Athabascan counterpart (Grosmont formation). These properties will enhance eases of processing and higher volume yield. From the scenario above, it therefore means an investment in the Nigeria tar sand deposit is a wise decision. However, the followings have to be taken into account

- ✓ The use of MSAR as fuel for power and steam generation in Nigeria
- ✓ The steam generator has to be direct contact.
- ✓ Electricity source has to be cogeneration.
- ✓ Water source has to be surface /underground fresh water.

The cost can be lowered if saline aquifer is chosen as source of water because there will be no pull on the water source used by local indigenes.

According to Duke du Plesis (2004), operating cost for SAGD could be $4 -$8, CSS $4 - $8 and for ISC $4 - $10. Comparing the results obtained from the simulation, and within the limit of mathematical computation with Duke du Plesis's, the model could be validated.

Technology	Duke du Plesis's	Nigeria	Canada (Grosmont
SAGD	$8-$14	$5.86 (approx $6)	$8.28 (approx $8)
CSS	$8-$14	$6.38 (approx $6)	$8.87 (approx $9)
ISC	$4-$10	$3.61 (approx $4)	$3.61 (approx $4)

It was reported in chapter two during literature review that MSAR is an alternative fuel for bitumen recovery in place of natural gas and heavy oil. This was built into the model for the Nigeria case. As shown in the table above, the unit operating cost for the Nigeria oil sand is substantially lower than for Canada (Grosmont formation). With the use of MSAR, at SOR of 2.5, the internal rate of return could be increased by as much as 6.7% (paragraph 2.5.1)

5.3 LIFE CYCLE COSTING.

The life cycle costing of a project or piece of equipment as explained in paragraph 3.5 and 3.6 estimates the revenue and expenses over the useful life of the project or equipment upon which economic decisions are made. The input data for the LCC simulation are as shown in tables 19, 20 and 21. See also sections 3.6.1 – 2.

The project life span was put at 10 years. And based upon Coker (1976) and the recovery rate used in the recovery model, daily output was projected. The tax and discount rate were put at 23% and 12% respectively.

The output from the simulation returned the values shown in table 22. As stated in section 3.5 above, economic decisions are made based on life cycle costing. If at least two of the NPVs are positive within the period, then the project is viable. The decision is also supported by the sizable IRR (36.35% for SAGD, 39.64% for ISC and 24.51% for CSS).

In selecting the best process technology for the Nigeria tar sand deposit based on the results above, some issues need to be taken into consideration. Key among them is the environment and response time to production.

The Nigeria tar sand deposit is heterogeneous in nature and there is the likelihood that the very high temperature generated by in situ combustion would lead to rapid break down of bands of biogenic limestone and calcareous shaly beds resulting in containment. Very high temperature would also lead to decomposition of calcium carbonate into lime and carbon dioxide. This is unacceptable due to its contribution to GHG.

Secondly, the model excluded the cost of oxygen/hydrogen used in the burning of the tar sand in situ. This cost sometimes becomes exorbitant especially when the oil or tar sand is very viscous like the Nigeria case.

ISC like CSS requires a waiting time period between injection and production. Sometimes this may take between 120 days and two years. (Paragraph 2.3.5.1)

In view of these therefore, although ISC turned out to have the highest NPV and IRR, it may not be the best choice for the Nigeria tar sand.

The best viable option for the Nigeria tar sand deposit may then be SAGD (NPV B$3,062 with IRR of 36.35%).

5.4 SENSITIVITY ANALYSIS

As explained in paragraph 3.7, the input into the LCC model was subjected to sensitivity analysis (What-if) using data table (two variable format). The input data (refinery cost, technology acquisition cost, MSAR cost and operating cost) were varied between -10% and +10%. The response of the IRR to these variations was observed. The combination of MSAR and refining cost have the greatest response to IRR for each technology (-4% to +4%). The combination of technology acquisition and operating cost only responded by mere plus or minus 1%. Therefore, refining and MSAR costs will be the overriding cost elements. See appendix 1

5.5 SUMMARY

This chapter documented the meaning of the results generated in the previous chapter and the credence they gave to the problem statement and the objectives of this dissertation.

In the next chapter conclusions will be drawn based on the findings of this dissertation.

CHAPTER 6: CONCLUSION AND RECOMMENDATION

In the previous chapter, the meanings of the results were outlined and the credence they lent to this dissertation was given.

This chapter draws conclusion based on the findings of this research and recommendations are also given.

6.1 CONCLUSION

This dissertation sought to investigate the similarities and differences between the Nigeria and Athabasca oil and tar sands deposit and the possibility of the transfer of process technology from Canada to Nigeria. It also sought to investigate the economic viability of the exploration of bitumen found in Nigeria with available technology. Based upon the study, the following conclusions are drawn

- The Nigeria and Athabasca tar sand deposit exhibit similar reservoir properties and occur in the same type of environment: - Deltaic, fluvial marine deposit in an incised valley lay down in strata. They are also divided into three types of formations each.
- The age and occurrence of the formations are also similar.
- The Nigeria tar sand will yield higher volume during hydro-cracking and the liquid products will be more thermally efficient with lesser sulphur content.
- The two tar sands have similar physical and chemical properties. The differences are within the limit of process technology adaptation.
- Any of the process technologies used in Canada is adaptable to the Nigeria situation with little modification to accommodate the differences (viscosity, resin, asphaltenes, sulphur and heavy metal contents)
- The recovery model and life cycle costing showed the unit operating cost adopting SAGD to be CA$40.59; CSS CA$44.14 and ISC CA$25.00. The NPV/IRR are B$3,062/36.35%, B$1,570/24.51%, and B$3,503/39.64% respectively. Though ISC returned the highest NPV and IRR, its environmental implication and response time to production makes it unattractive. The best solution for Nigeria is therefore SAGD

6.2 RECOMMENDATION

Having determined the best viable option for exploring Nigeria tar sands, it is herewith recommended that an investment in the exploration of the Nigeria bitumen will be a wise economic decision upon which the following recommendations are made.

- A detailed social economic impact of the project coupled with Community engagement should be included in the EIA. Socio-economic impact and Community engagement should be seen as developmental tool and should be part of an EIA.(See Ajoguntan K.A (2008) submitted to North West University
- Relocation is favoured by the communities. Should the Government or any investor want to develop the deposit, the people should be relocated to a new settlement.
- Pilot projects should be set up to demonstrate the viability of the tar sand deposit. This has the potential to compliment the power generating capacity of Ondo State in particular and the country in general. It will also put in good shape some of the bad roads in the South Western part of the country.

6.3 RECOMMENDATION FOR FURTHER RESEARCH.

The Kaduna refinery was commissioned in 1980 to provide petroleum products for the Northern part of the country. At that time, the federal government entered a bilateral trade agreement with Venezuela for the supply of synthetic crude to the refinery. This explained why the refinery was built to have bitumen/asphalt as one of its product. The trade agreement has since collapsed and the bitumen unit of the refinery has been out of use. The government has resulted to importing bitumen from Ivory Coast. Therefore, a research into the capability of the Kaduna refinery to handle products from the Nigeria tar sand deposit should be carried out.

During the course of this dissertation, it was discovered that the use of saline aquifer as a source of process water could substantially reduce the overall production cost. Therefore, a research into the presence of Saline Aquifer within a close distance of the tar sand belt should be carried out.

Some of the financial figures entered into the financial model are based on history. Even though efforts were made to update these figures by way of escalation, it is hereby recommended that further work be carried out to verify the accuracy of these figures.

Input of data into the PTAC model was done with absolute care and efforts were made to minimise the effects of bloated assumptions on the output. It is however hereby recommended that the assumptions built into the model be experimentally verified.

Bitumen viscosity is a key variable in evaluating the Nigeria bitumen formation plays. The down dip formation reservoirs are prospective and merit further work such as the acquisition of additional geotechnical and geochemical data.

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APPENDICES

Appendix 1 Life cycle costing for SAGD

Appendix 2 Life cycle costing for in situ combustion

Appendix 3 Life cycle costing for cyclic steam stimulation

APPENDIX 1

Life cycle costing for SAGD

Life Cycle Cost Worksheet

<-Yellow Boxes Are For Data Input

Discount Rate (%)--> 12% | Project Life (35 yrs max)--> 10 | Tax Provision (%)--> 23%

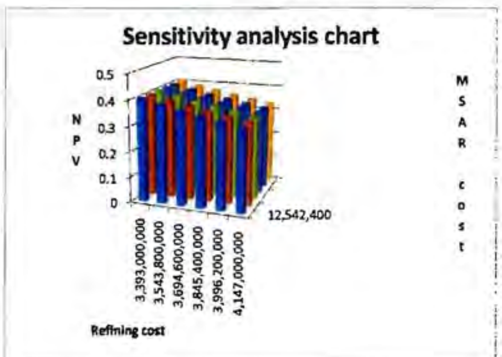
$3,062,544,012 <-Net Present Value | 36.35% <-Internal Rate Of Return

Capital Costs:	0	1	2	3	4	5	6	7	8	9	10
Capital Acquisition Costs	$210,000,000										
Acquisition Costs:											
Operating Costs (production & supply costs)		$850,537,600	$952,602,112	$1,066,914,365	$1,194,944,089	$1,338,337,380	$1,498,937,686	$1,678,810,409	$1,880,267,659	$2,105,899,778	$2,358,607,752
Insurance cost		$79,878,720	$89,464,166	$100,199,866	$112,223,850	$125,690,712	$140,773,598	$157,666,430	$176,586,401	$197,776,769	$221,509,982
Maintenance Costs (Contract, All inclusive)				$79,878,720	$89,464,166	$100,199,866	$112,223,850	$125,690,712	$140,773,598	$157,666,430	$176,586,401
Spare Parts & Logistics Costs											
Facilities & Construction Costs (MSAR)		$13,936,000									
Facilities & Construction Costs(Refining)		$3,770,000,000									
Technical Data Costs											
Documentation Costs											
Annual recuring costs											
Other periodic costs											
Disposal Costs											
Savings:											
Annual Savings (use positive #s)		$1,249,868,951	$1,249,868,951	$3,589,868,951	$3,589,868,951	$3,589,868,951	$3,589,868,951	$3,589,868,951	$3,589,868,951	$3,589,868,951	$3,589,868,951

NPV & IRR Calculations:	0	1	2	3	4	5	6	7	8	9	10
Capital equipment	$210,000,000										
Costs	$0	$4,714,352,320	$1,042,066,278	$1,246,992,952	$1,396,632,106	$1,564,227,959	$1,751,935,134	$1,962,167,551	$2,197,627,658	$2,461,342,977	$2,756,704,135
Savings		$1,249,868,951	$1,249,868,951	$3,589,868,951	$3,589,868,951	$3,589,868,951	$3,589,868,951	$3,589,868,951	$3,589,868,951	$3,589,868,951	$3,589,868,951
Straight Line Depreciation		$21,000,000	$21,000,000	$21,000,000	$21,000,000	$21,000,000	$21,000,000	$21,000,000	$21,000,000	$21,000,000	$21,000,000
Profit Before Taxes	$0	-$3,485,483,369	$186,802,673	$2,321,875,999	$2,172,236,845	$2,004,840,992	$1,816,933,817	$1,606,701,400	$1,371,241,293	$1,107,525,974	$812,184,616
Tax Provision @ 22.5% Of Profit Before Tax	$0	$784,233,758	-$42,030,601	-$522,422,100	-$488,753,290	-$451,044,223	-$408,810,109	-$361,507,615	-$308,529,291	-$249,193,344	-$182,737,084
Net Income can be profit or loss	$0	-$2,701,249,611	$144,772,071	$1,799,453,899	$1,683,483,555	$1,553,596,769	$1,408,123,708	$1,245,193,585	$1,062,712,002	$858,332,630	$629,427,732
Add Back Depreciation		$21,000,000	$21,000,000	$21,000,000	$21,000,000	$21,000,000	$21,000,000	$21,000,000	$21,000,000	$21,000,000	$21,000,000
Cash Flow (Net Income + Depreciation)	-$210,000,000	-$2,680,249,611	$165,772,071	$1,820,453,899	$1,704,483,555	$1,574,596,769	$1,429,123,708	$1,266,193,585	$1,083,712,002	$879,332,630	$650,427,732
Discount Factors @ 12%	1.0000	0.8929	0.7972	0.7118	0.6355	0.5674	0.5066	0.4523	0.4039	0.3606	0.3220
Present Value	-$210,000,000	-$2,393,080,010	$132,152,480	$1,295,763,128	$1,083,230,113	$893,468,494	$724,038,547	$572,761,674	$437,693,102	$317,096,162	$209,420,322
Net Present Value	$3,062,544,012										
Internal Rate Return	36.35%										

<-Requires at least one positive and one negative number in the present value row 32

Year-->	0	1	2	3	4	5	6	7	8	9	10



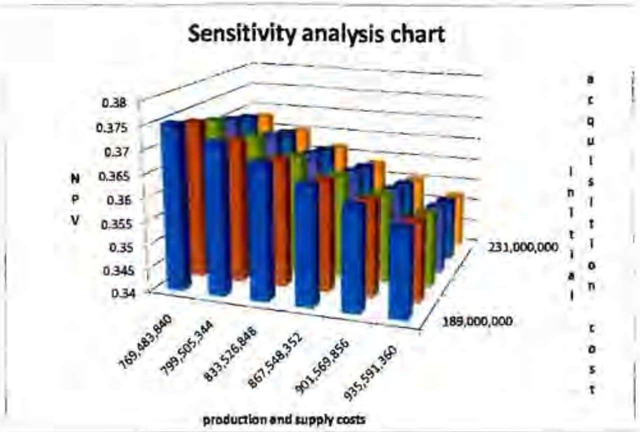
36.35%	3,393,000,000	3,543,800,000	3,694,600,000	3,845,400,000	3,996,200,000	4,147,000,000
12,542,400	0.40367752	0.386913915	0.371140189	0.356264044	0.34220452	0.328890306
13,099,840	0.403613605	0.386853844	0.371083599	0.356210615	0.342153972	0.328842392
13,657,280	0.403549704	0.386793787	0.371027021	0.356157197	0.342103434	0.328794487
14,214,720	0.403485819	0.386733744	0.370970455	0.356103791	0.342052907	0.328746591
14,772,160	0.403421948	0.386673714	0.370913902	0.356050395	0.342002389	0.328698704
15,329,600	0.403358093	0.386613697	0.370857361	0.355997011	0.341951882	0.328650827

	3,393,000,000	3,543,800,000	3,694,600,000	3,845,400,000	3,996,200,000	4,147,000,000
12,542,400	0.40367752	0.386913915	0.371140189	0.356264044	0.34220452	0.328890306
13,099,840	0.403613605	0.386853844	0.371083599	0.356210615	0.342153972	0.328842392
13,657,280	0.403549704	0.386793787	0.371027021	0.356157197	0.342103434	0.328794487
14,214,720	0.403485819	0.386733744	0.370970455	0.356103791	0.342052907	0.328746591
14,772,160	0.403421948	0.386673714	0.370913902	0.356050395	0.342002389	0.328698704
15,329,600	0.403358093	0.386613697	0.370857361	0.355997011	0.341951882	0.328650827

Sensitivity analysis (Data table format)

APPENDIX 1

Life cycle costing for SAGD



Sensitivity analysis (Data table format)

	769,483,840	799,505,344	833,526,848	867,548,352	901,569,856	935,591,360
189,000,000	0.37516928	0.3720825	0.36862801	0.36521885	0.36185404	0.35853265
197,000,000	0.3737908	0.3707238	0.36729121	0.36390341	0.36055945	0.3572584
205,800,000	0.37228658	0.36924105	0.36583222	0.36246761	0.35914628	0.35586732
214,200,000	0.3708624	0.36783707	0.36445062	0.36110784	0.35780783	0.35454968
222,000,000	0.36954999	0.36654318	0.36317724	0.35985449	0.35657402	0.35333495
231,000,000	0.36804753	0.36506181	0.36171922	0.35841927	0.35516106	0.35194374

36.35%	769,483,840	799,505,344	833,526,848	867,548,352	901,569,856	935,591,360
189,000,000	0.37516928	0.3720825	0.36862801	0.36521885	0.36185404	0.35853265
197,000,000	0.3737908	0.3707238	0.36729121	0.36390341	0.36055945	0.3572584
205,800,000	0.37228658	0.36924105	0.36583222	0.36246761	0.35914628	0.35586732
214,200,000	0.3708624	0.36783707	0.36445062	0.36110784	0.35780783	0.35454968
222,000,000	0.36954999	0.36654318	0.36317724	0.35985449	0.35657402	0.35333495
231,000,000	0.36804753	0.36506181	0.36171922	0.35841927	0.35516106	0.35194374

APPENDIX 2

Life cycle costing for ISC

Life Cycle Cost Worksheet

<--Yellow Boxes Are For Data Input

Discount Rate (%)--> 12% | *Project Life (35 yrs max)-->* 10 | *Tax Provision (%)-->* 23%

$3,502,515,167 <--Net Present Value | 39.64% <--Internal Rate Of Return

Capital Costs:	0	1	2	3	4	5	6	7	8	9	10
Capital Acquisition Costs	$341,250,000										
Acquisition Costs:											
Operating Costs (production &supply costs)		$786,940,000	$881,372,800	$987,137,536	$1,105,594,040	$1,370,936,610	$1,535,449,003	$1,719,702,884	$1,926,067,230	$2,157,195,297	$2,416,058,733
Insurance cost		$82,503,720	$92,404,166	$103,495,666	$115,911,786	$129,821,201	$145,399,745	$162,847,714	$182,389,440	$204,276,173	$228,789,313
Maintenance Costs (Contract, All inclusive)				$82,503,720	$92,404,166	$103,495,666	$115,911,786	$129,821,201	$145,399,745	$162,847,714	$182,389,440
Spare Parts & Logistics Costs											
Facilities & Construction Costs (MSAR)		$13,936,000									
Facilities & Construction Costs (Refining)		$3,770,000,000									
Technical Data Costs											
Documentation Costs											
Annual recuring costs											
Other periodic costs											
Disposal Costs											
Savings:											
Annual Savings (use positive #s)		$1,368,158,151	$1,368,158,151	$3,708,158,151	$3,708,158,151	$3,708,158,151	$3,708,158,151	$3,708,158,151	$3,708,158,151	$3,708,158,151	$3,708,158,151

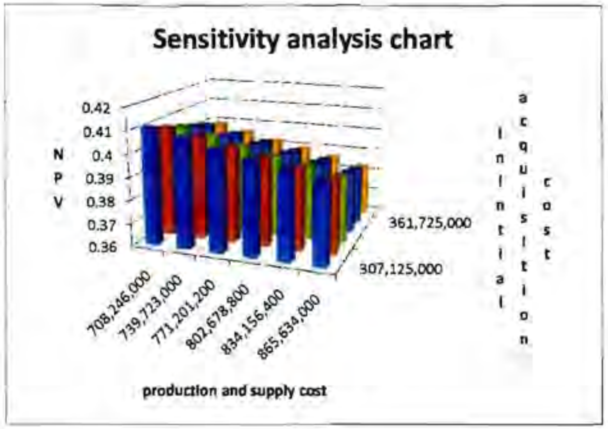
NPV & IRR Calculations:	0	1	2	3	4	5	6	7	8	9	10
Capital equipment	$341,250,000										
Costs	$0	$4,653,379,720	$973,776,966	$1,173,136,922	$1,313,909,993	$1,604,253,477	$1,796,760,534	$2,012,371,798	$2,253,856,414	$2,524,319,184	$2,827,237,486
Savings		$1,368,158,151	$1,368,158,151	$3,708,158,151	$3,708,158,151	$3,708,158,151	$3,708,158,151	$3,708,158,151	$3,708,158,151	$3,708,158,151	$3,708,158,151
Straight Line Depreciation		$34,125,000	$34,125,000	$34,125,000	$34,125,000	$34,125,000	$34,125,000	$34,125,000	$34,125,000	$34,125,000	$34,125,000
Profit Before Taxes	$0	-$3,319,346,569	$360,256,185	$2,500,896,229	$2,360,123,158	$2,069,779,674	$1,877,272,617	$1,661,661,353	$1,420,176,737	$1,149,713,967	$846,795,665
Tax Provision @ 23% Of Profit Before Tax	$0	$763,449,711	-$82,858,922	-$575,206,133	-$542,828,326	-$476,049,325	-$431,772,702	-$382,182,111	-$326,640,649	-$264,434,212	-$194,763,003
Net Income can be profit or loss	$0	-$2,555,896,858	$277,397,262	$1,925,690,096	$1,817,294,832	$1,593,730,349	$1,445,499,915	$1,279,479,241	$1,093,536,087	$885,279,755	$652,032,662
Add Back Depreciation		$34,125,000	$34,125,000	$34,125,000	$34,125,000	$34,125,000	$34,125,000	$34,125,000	$34,125,000	$34,125,000	$34,125,000
Cash Flow (Net Income + Depreciation)	-$341,250,000	-$2,521,771,858	$311,522,262	$1,959,815,096	$1,851,419,832	$1,627,855,349	$1,479,624,915	$1,313,604,241	$1,127,661,087	$919,404,755	$686,157,662
Discount Factors @ 12%	1.0000	0.8929	0.7972	0.7118	0.6355	0.5674	0.5066	0.4523	0.4039	0.3606	0.3220
Present Value	-$341,250,000	-$2,251,582,016	$248,343,640	$1,394,957,675	$1,176,610,774	$923,688,842	$749,624,030	$594,207,848	$455,443,400	$331,546,572	$220,924,403
Net Present Value	$3,502,515,167										
Internal Rate Return	39.64%	<--Requires at least one positive and one negative number in the present value row 32									
Year-->	0	1	2	3	4	5	6	7	8	9	10

APPENDIX 2

Life cycle costing for ISC

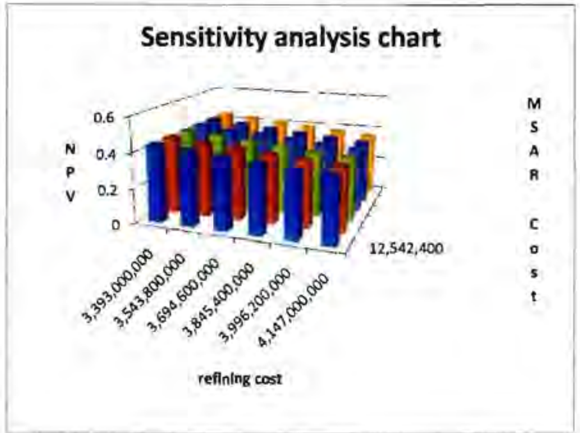
Sensitivity analysis (Data table format)

	708,246,000	739,723,000	771,201,200	802,678,800	834,156,400	865,634,000
307,125,000	0.410931606	0.407537992	0.404184742	0.40087128	0.397596789	0.394360538
320,775,000	0.408382707	0.405026584	0.401710008	0.398432422	0.395193034	0.391991134
334,425,000	0.405867292	0.402547835	0.399267133	0.396024649	0.392819613	0.389651337
348,075,000	0.403384561	0.400100972	0.39685537	0.39364724	0.390475831	0.387340474
361,725,000	0.400933742	0.39768525	0.394474001	0.391299499	0.388161014	0.385057896
375,375,000	0.39851409	0.395299949	0.39212233	0.388980754	0.385874513	0.382802973



39.64%	708,246,000	739,723,000	771,201,200	802,678,800	834,156,400	865,634,000
307,125,000	0.410931606	0.407537992	0.404184742	0.40087128	0.397596789	0.394360538
320,775,000	0.408382707	0.405026584	0.401710008	0.398432422	0.395193034	0.391991134
334,425,000	0.405867292	0.402547835	0.399267133	0.396024649	0.392819613	0.389651337
348,075,000	0.403384561	0.400100972	0.39685537	0.39364724	0.390475831	0.387340474
361,725,000	0.400933742	0.39768525	0.394474001	0.391299499	0.388161014	0.385057896
375,375,000	0.39851409	0.395299949	0.39212233	0.388980754	0.385874513	0.382802973

	3,393,000,000	3,543,800,000	3,694,600,000	3,845,400,000	3,996,200,000	4,147,000,000
12,542,400	0.438132329	0.420783542	0.404421464	0.3889594	0.374320519	0.36043651
13,099,840	0.438066265	0.420721298	0.4043627	0.388903816	0.374267846	0.360386509
13,657,280	0.438000216	0.420659068	0.404303949	0.388848242	0.374215183	0.360336519
14,214,720	0.437934182	0.420596851	0.40424521	0.38879268	0.37416253	0.360286538
14,772,160	0.437868162	0.420534648	0.404186483	0.388737129	0.374109888	0.360236566
15,329,600	0.437802157	0.420472459	0.404127769	0.388681589	0.374057256	0.360186604



39.64%	3,393,000,000	3,543,800,000	3,694,600,000	3,845,400,000	3,996,200,000	4,147,000,000
12,542,400	0.438132329	0.420783542	0.404421464	0.3889594	0.374320519	0.36043651
13,099,840	0.438066265	0.420721298	0.4043627	0.388903816	0.374267846	0.360386509
13,657,280	0.438000216	0.420659068	0.404303949	0.388848242	0.374215183	0.360336519
14,214,720	0.437934182	0.420596851	0.40424521	0.38879268	0.37416253	0.360286538
14,772,160	0.437868162	0.420534648	0.404186483	0.388737129	0.374109888	0.360236566
15,329,600	0.437802157	0.420472459	0.404127769	0.388681589	0.374057256	0.360186604

APPENDIX 3

Life cycle costing for CSS

Life Cycle Cost Worksheet

Discount Rate (%)--> 12% | $1,570,907,781 <--Net Present Value

Project Life (35 yrs max)--> 10 | 24.51% <--Internal Rate Of Return

<--Yellow Boxes Are For Data Input

Tax Provision (%)--> 23%

Capital Costs:	0	1	2	3	4	5	6	7	8	9	10
Capital Acquisition Costs	$341,250,000										
Acquisition Costs:											
Operating Costs (production & supply costs)		$936,672,800	$1,049,073,536	$1,174,962,360	$1,315,957,844	$1,473,872,785	$1,650,737,519	$1,848,826,021	$2,070,685,144	$2,319,167,361	$2,597,467,444
Insurance cost		$82,503,720	$92,404,166	$103,492,666	$115,911,786	$129,821,201	$145,399,745	$162,847,714	$182,389,440	$204,276,173	$228,789,313
Maintenance Costs (Contract, All inclusive)				$82,503,720	$92,404,166	$103,492,666	$115,911,786	$129,821,201	$145,399,745	$162,847,714	$182,389,440
Spare Parts & Logistics Costs											
Facilities & Construction Costs (MSAR)		$13,936,000									
Facilities & Construction Costs (Refining)		$3,770,000,000									
Technical Data Costs											
Documentation Costs											
Annual recuring costs											
Other periodic costs											
Disposal Costs											
Savings:											
Annual Savings (use positive #s)		$1,080,846,951	$1,080,846,951	$3,420,846,951	$3,420,846,951	$3,420,846,951	$3,420,846,951	$3,420,846,951	$3,420,846,951	$3,420,846,951	$3,420,846,951

NPV & IRR Calculations:	0	1	2	3	4	5	6	7	8	9	10
Capital equipment	$341,250,000										
Costs	$0	$4,803,112,520	$1,141,477,702	$1,360,958,747	$1,524,273,796	$1,707,186,652	$1,912,049,050	$2,141,494,936	$2,398,474,328	$2,686,291,248	$3,008,646,198
Savings		$1,080,846,951	$1,080,846,951	$3,420,846,951	$3,420,846,951	$3,420,846,951	$3,420,846,951	$3,420,846,951	$3,420,846,951	$3,420,846,951	$3,420,846,951
Straight Line Depreciation		$34,125,000	$34,125,000	$34,125,000	$34,125,000	$34,125,000	$34,125,000	$34,125,000	$34,125,000	$34,125,000	$34,125,000
Profit Before Taxes	$0	-$3,756,390,569	-$94,755,751	$2,025,763,204	$1,862,448,155	$1,679,535,299	$1,474,672,901	$1,245,227,015	$988,247,623	$700,430,703	$378,075,753
Tax Provision @ 23% Of Profit Before Tax	$0	$863,969,831	$21,793,823	-$465,925,537	-$428,363,076	-$386,293,119	-$339,174,767	-$286,402,213	-$227,296,953	-$161,099,062	-$86,957,423
Net Income can be profit or loss	$0	-$2,892,420,738	-$72,961,929	$1,559,837,667	$1,434,085,079	$1,293,242,180	$1,135,498,134	$958,824,801	$760,950,669	$539,331,641	$291,118,330
Add Back Depreciation		$34,125,000	$34,125,000	$34,125,000	$34,125,000	$34,125,000	$34,125,000	$34,125,000	$34,125,000	$34,125,000	$34,125,000
Cash Flow (Net Income + Depreciation)	-$341,250,000	-$2,858,295,738	-$38,836,929	$1,593,962,667	$1,468,210,079	$1,327,367,180	$1,169,623,134	$992,949,801	$795,075,669	$573,456,641	$325,243,330
Discount Factors @ 12%	1.0000	0.8929	0.7972	0.7118	0.6355	0.5674	0.5066	0.4523	0.4039	0.3606	0.3220
Present Value	-$341,250,000	-$2,552,049,766	-$30,960,562	$1,134,551,142	$933,074,048	$753,183,786	$592,567,480	$449,160,064	$321,117,728	$206,794,214	$104,719,648
Net Present Value	$1,570,907,781										
Internal Rate Return	24.51%	<--Requires at least one positive and one negative number in the present value row 32									
Year-->	0	1	2	3	4	5	6	7	8	9	10

APPENDIX 3

Life cycle costing for CSS

Sensitivity analysis (Data table format) for CSS

24.51%	843,005,520	880,472,432	917,939,344	955,406,256	992,873,168	1,030,340,080
307,125,000	0.256127957	0.25321236	0.25033305	0.24748929	0.24468035	0.241905521
320,775,000	0.254532975	0.25164209	0.24878693	0.24596675	0.24318085	0.240428547
334,452,000	0.252951085	0.25008454	0.24725316	0.24445621	0.24169302	0.23896292
348,075,000	0.251391308	0.2485486	0.2457405	0.24296632	0.24022538	0.23751703
361,725,000	0.249844032	0.24702481	0.24423966	0.24148791	0.2387689	0.236081996
375,375,000	0.248312083	0.24551595	0.24275337	0.24002369	0.23732626	0.23466046

	843,005,520	880,472,432	917,939,344	955,406,256	992,873,168	1,030,340,080
307,125,000	0.256127957	0.25321236	0.25033305	0.24748929	0.24468035	0.241905521
320,775,000	0.254532975	0.25164209	0.24878693	0.24596675	0.24318085	0.240428547
334,452,000	0.252951085	0.25008454	0.24725316	0.24445621	0.24169302	0.23896292
348,075,000	0.251391308	0.2485486	0.2457405	0.24296632	0.24022538	0.23751703
361,725,000	0.249844032	0.24702481	0.24423966	0.24148791	0.2387689	0.236081996
375,375,000	0.248312083	0.24551595	0.24275337	0.24002369	0.23732626	0.23466046

24.51%	3,393,000,000	3,543,800,000	3,694,600,000	3,845,400,000	3,996,200,000	4,147,000,000
12,542,400	0.275082623	0.262670903	0.250880816	0.23966254	0.228971551	0.218767936
13,099,840	0.275035531	0.262626208	0.250838323	0.239622075	0.228932959	0.218731077
13,657,280	0.274988449	0.262581521	0.250795838	0.239581617	0.228894373	0.218694223
14,214,720	0.274941375	0.262536843	0.25075336	0.239541167	0.228855794	0.218657376
14,772,160	0.274894311	0.262492174	0.250710891	0.239500724	0.228817222	0.218620535
15,329,600	0.274847257	0.262447513	0.250668429	0.239460288	0.228778656	0.2185837

	3,393,000,000	3,543,800,000	3,694,600,000	3,845,400,000	3,996,200,000	4,147,000,000
12,542,400	0.275082623	0.262670903	0.250880816	0.23966254	0.228971551	0.218767936
13,099,840	0.275035531	0.262626208	0.250838323	0.239622075	0.228932959	0.218731077
13,657,280	0.274988449	0.262581521	0.250795838	0.239581617	0.228894373	0.218694223
14,214,720	0.274941375	0.262536843	0.25075336	0.239541167	0.228855794	0.218657376
14,772,160	0.274894311	0.262492174	0.250710891	0.239500724	0.228817222	0.218620535
15,329,600	0.274847257	0.262447513	0.250668429	0.239460288	0.228778656	0.2185837