Oil Shale, 2016, Vol. 33, No. 3, pp. 272–289
doi: 10.3176/oil.2016.3.06
ISSN 0208-189X

ECONOMIC SUSTAINABILITY OF ESTONIAN SHALE OIL INDUSTRY UNTIL 2030

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Abstract. *The objective of this paper is to elucidate the sustainability of Estonian shale oil industry until the year 2030 in terms of the full cycle breakeven cost of oil. The full cycle cost is rapidly increasing due to increasing necessary capital expenditure, increased national taxation and the European Union (EU) carbon (C) emissions abatement policies. There is a fair amount of uncertainty about all three components, which makes scenario analysis an appropriate tool to estimate the survivability of Estonian shale oil industry scenarios in the next 15 years.*

Past economic performance alone is not a proper guide for future in case of Estonian oil shale industry. However, heavy investments have been made in the industry since 2011 and several hundred million euros are being invested or planned to invest in the replacement of old capacity and raising new oil production capacity.

Analysis shows that, indeed, in certain scenarios the shale oil breakeven price is at the highest end of global crude oil production projects, thus raising questions of the industry's survivability in case of multiyear sustained global oil prices below 90 USD/bbl. Conclusions of the study are relevant to analyzing the full cycle costs of other promising global shale oil projects.

Keywords: *national energy policy, industrial policy, resource taxation, shale oil, mining regulations.*

1. Introduction

Since the 2000s there has been a substantial global effort to have a diversified supply of liquid fuels from nonconventional sources [1]. Oil shale represents a large energetic resource with the resource estimate of 2.8 trillion barrels of crude oil, the US Green River formation with 1.5 trillion barrels of crude oil signifying its equivalent [2]. This potential has been exploited globally on a relatively small scale with the exception of Estonia where oil shale means the country's major energy supply. Historically the main utiliza-

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tion of oil shale in Estonia since the 1960s has been in power generation, but for several years there has been a significant development of new technology in the direction of shale oil (SO) production. Other global shale oil producers are currently China and Brazil. Estonia's experience is much appreciated globally in tapping large oil shale reserves in Jordan, the U.S., Morocco, Ukraine and elsewhere. Thus, Estonian case is relevant in terms of understanding the economics of and limitations on the use of these reserves because there is a lack of empirical data on shale oil commerciality [3].

Nationally oil shale represents a major industry for Estonia with three companies and an aggregate turnover of over 1 billion EUR, a high contribution to the state budget, employment of more than 7000, and as an indispensable element in national power supply. Due to the rise of oil prices in 2004–08, there is a strong drive to increase oil shale utilization in oil production and decrease in power generation in the coming years, but that drive has been recently stymied by concerns over national taxation, the European Union (EU) CO_2 abatement policies and the sharp fall in oil prices since mid-2014. Given that there is a fair amount of uncertainty regarding cost components such as capital cost, CO_2 cost and taxation, it appears that scenario analysis is the most appropriate tool to examine the full cycle cost of shale oil. No such analysis has been performed or published so far.

The objective of this study is to find out the sustainability of Estonian shale oil industry until the year 2030 in terms of the full cycle breakeven cost of oil and consider it in relationship with other global crude oil projects. The author used data of Estonian oil shale company Viru Keemia Grupp AS (VKG) as an example to investigate his firsthand knowledge and VKG's position as an oil producer having the newest facilities (mines, oil processing units, etc.).

The current study is organized as follows. Chapter 2 discusses the full cycle cost of oil. Chapter 3 considers the current situation of Estonian oil shale industry and risks involved. Chapter 4 presents a model for assessing the full cycle breakeven cost of oil in different scenarios. Chapter 5 examines implications of the model and Chapter 6 draws conclusions.

2. Full cycle cost of oil

While shale oil is a somewhat unique product mainly used as a heavy fuel oil or bunker fuel, it should also be said that most global crude oils from particular deposits are similarly unique with the individual American Petroleum Institute (API) gravity, sulphur content and molecular characteristics. In cooperation with international partners, VKG has developed technical and economical solutions to refine shale oil to diesel fuel, but plans to build a refinery in 2013 were put on hold. Ultimately, shale oil is a particular kind of crude oil competing on the market with the latter for market place as a product and investment opportunity. The direct pricing mechanism for SO is based on heavy fuel oil with a 1% sulphur content, which is priced at Rotterdam. Thus the same economic analysis applies to shale oil as to other conventional and unconventional crude oils.

The full cycle conventional oil project cost might be represented as follows:

1. Property Acquisition Costs: The cost of acquiring unproved property is an on-going part of the business.
2. Exploration Costs: The company must cover the cost of geological and geophysical work (G&G), licensing rounds, signature bonuses and the costs of drilling exploration wells.
3. Development Costs: The company must cover the costs of acquiring, constructing and installing production facilities and drilling development wells.
4. Production Costs: These are the costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells.
5. Transportation Costs: The company must cover the cost of transporting its product to market.
6. Production Taxes: An international oil company (IOC) must pay production taxes or royalties to the host state.
7. Return on Capital: An IOC must at least cover its cost of capital over the medium term. Otherwise it is destroying value for its shareholders.

Specific to Estonia is that geological exploration for the greatest part of the Estonian oil shale deposit was carried out in 1960–86. Currently there is no need to acquire land for deposit exploration and development because oil shale and most of the land are owned by the state and the land lease rate is quite low. However, applying for mining and relevant environmental permits is a rather expensive and lengthy process. In case of Estonian oil shale the related costs might be represented as follows:

1. mining permit costs: costs related to applying for an oil shale mining permit;
2. deposit development costs: costs related to opening a new oil shale mine;
3. technology development costs: costs related to developing and implementing an innovative technology or adapting it to a particular situation to achieve a continuous commercial production of SO and related products (heat, steam, power, chemicals);
4. production costs: costs of materials, equipment, manpower, services, capital and interests, and other consumables utilized in the production process;
5. production taxes: environmental charges and other taxes incurred during production;
6. return on capital.

Over the long term, the oil and gas industry must incur certain costs in order to find, develop and produce oil and gas. This full set of costs the industry needs to incur in order to sustain or grow production is known as full cycle costs. If crude oil or natural gas prices are generally persisting above these full cycle costs, the industry has an incentive to sustain investment and activity in the sector. However, if the margin between full cycle costs and prices is squeezed for prolonged periods, the industry finds, before too long, that investment is not sustainable and capital spending, production and reserve replacement will begin to fall off as a result [4]. This will eventually lead to production decline and shutdown. Figure 1 gives an overview of major global oil capacity projects compiled by Citi Research.

While it would be rational to consider that most companies would want to develop projects in the 1st and 2nd quartiles with low breakeven prices and presumably profitability, the reality in the last years has been that there have just been no cheap projects left globally and companies need to develop also more expensive projects to replace their reserves and production capacities in the medium term [6]. This has led to a substantial exploration and production capital cost inflation in recent years as illustrated by Figure 2.

Another breakeven cost curve is shown in Figure 3. Among projects added within the past two years, none had a breakeven price below 70 USD/bbl and most had breakeven prices within the 80–100 USD/bbl band. The latter group includes higher-cost US shale oil and deepwater projects as well as the majority of Canadian oil sands projects. The US Goldman Sachs Group [7] clearly states: ”The oil price required for the western

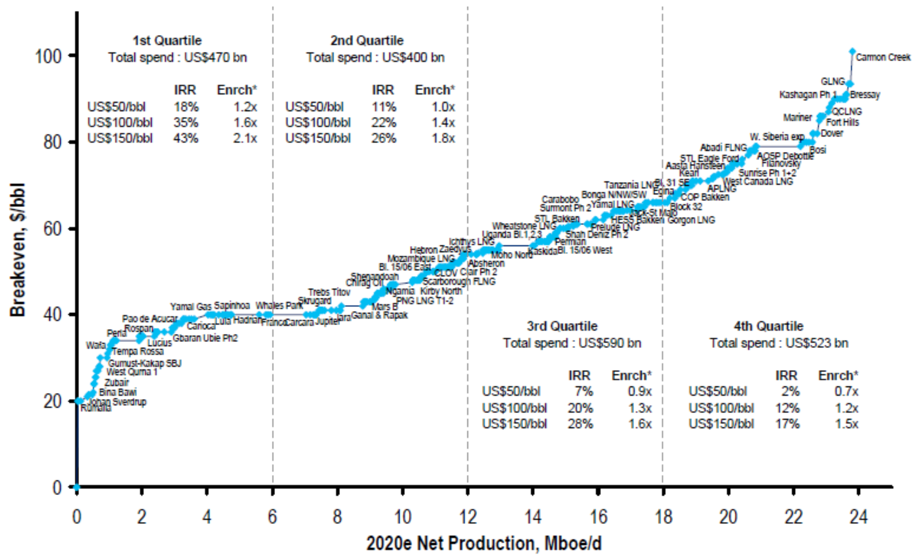

Fig. 1. New investment cost curve by quartiles of breakeven price [5]. (Abbreviations used: IRR – internal rate of return, bbl – barrels, bn – billion, Mboe – millions barrels of oil equivalent.)

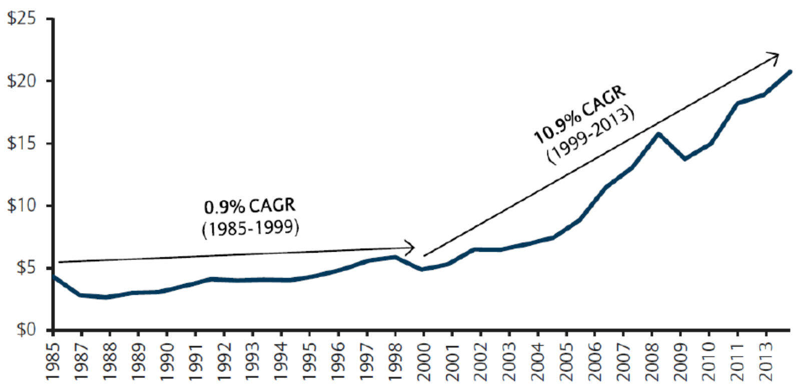

Fig. 2. Exploration and production capital cost in 1985–2013 [7]. (Abbreviation used: CAGR – compound annual growth rate.)

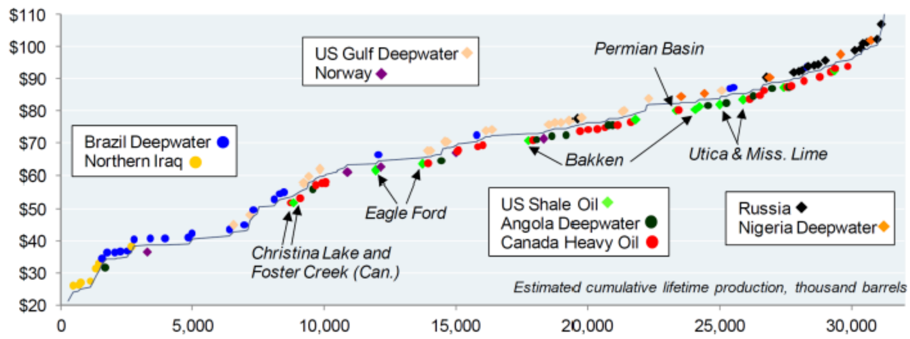

Fig. 3. Breakeven cost curve of new oil projects including fiscal costs [7].

oil Majors to be free cash flow neutral after capex (capital expenditure) and dividends is much higher than is implied by the major new projects On our estimates it has increased from c $80/bl in 2008–11 to over $120/bl currently, as a result of higher decline rates, increasing maintenance capex and higher costs.“ The past few years have provided ample global examples of major oil projects if breakeven cost was not achievable or had a high degree of uncertainty, projects were delayed or abandoned entirely [6].

The substantial fall of oil prices in the second half of 2014 and levelling at 60–65 USD/bbl has led to an about 25% reduction or 100 billion USD in new capital expenditure or project delays into new oil upstream capacity, particularly in Canadian oil sands projects, according to a consultancy Rystad Energy [8]. Breakeven prices presented in Figures 1 and 3 do not represent short-term price fluctuations, but rather long-term, 10+ years price levels need to break even. It is relevant to note that breakeven prices are not constant in time even for particular oil plays. Recent examples are reduction of breakeven costs in US shale oil plays through increased productivity of wells, higher selectivity in drilling and other methods [9].

The profitability measure used in full cycle breakeven cost assessment is universally Return on Investment (ROI), which is calculated Net Profit as percentage of Long-term Investments (Long-term Liabilities plus Stockholder's Equity). ROI displays the yield which the company generates on Long-term Investments.

Essentially similar is Return on Capital Employed (ROCE), which is the relationship of Earnings Before Interest and Tax (EBIT) to Capital Employed where Capital Employed is Total Assets minus Current Liabilities. Both concepts benefit, compared to Return on Assets or Return on Equity, from inclusion of long-term liabilities into the equation. For these and the reason of available data the concept ROI has been employed in the current analysis.

3. Estonian oil shale industry

3.1. Current situation

Estonian oil shale industry today, with the mining output and processing of approximately 15 million t of oil shale, consists of three enterprises. The largest is the 100% Estonian government owned Eesti Energia AS (EE) that utilizes 11 million t of oil shale for power generation, producing 10 TWh of electricity, and 1.7 million t for oil production, producing 200 000 t of oil. EE's turnover was 822 million EUR in 2013 [10]. The second largest is the private company Viru Keemia Grupp AS (VKG) that processes and produces 370 000 t of oil and whose turnover was 220 million EUR in the year 2013 [11]. Third is the private enterprise Kiviõli Keemiatööstus OÜ (KKT) that processes 0.6 million t of oil shale, producing 60 000 t of oil. The turnover of KKT was 35 million EUR [12]. As of early 2014, the total production of Estonian oil industry was around 30 000 barrels per day.

Most of the mines and production units in the industry are the heritage from the Soviet period, though, with many renovations and technology improvements in the last 15 years. The oil industry in Estonia almost went bankrupt and was on the verge of shutdown in 1997–98 due to the collapse of world oil prices, but ever since the increase of prices has seen a steady investment in the replacement of aging capacity and launching new capacity. The most active investor has been VKG that completed a new oil shale processing unit Petroter in 2010 and another in 2014, opened a new oil shale mine in Ojamaa in 2013 and is currently constructing a third Petroter unit. Thus 59% of the oil will be produced from new units by the year 2016. The new Petroter unit will require further investments in a new single oil shale processing unit for power generation to utilize pyrolysis gases, investments in emission gases purification, oil shale ash depositing and other measures to the amount of 20 million EUR.

Slightly behind in investments is EE that in 2015 brought into production a new 300 MWe circulating fluidized bed power generation unit and a new oil production unit named Enefit 280, which is able to process 2 million t of oil shale and produce 5000 barrels of shale oil per day. EE has ambitious plans to replace within 10 years most of the current oil shale power generation units with oil production units, which also produce power from cogeneration and waste gases. KKT has plans to build four new small generator units, but strategically to use up all of its oil shale mining capacity of 1.9 million t from the current level of 0.6 million t. In total, the industry employs directly around 7000 people of the 82 500 labour force in Ida-Virumaa region, is a major government revenue source with close to 300 million EUR tax and dividend revenue and a substantial national industrial sector [13].

3.2. Risk factors of Estonian shale oil industry

Despite the high crude oil prices in 2010–early 2014, Estonia's oil shale sector faces many industry and EU specific risks.

3.2.1. EU climate policy

The Council of the European Union (Council) has set the objective to reduce in the European Union (EU) greenhouse gas (GHG) emissions by the year 2050 by 80–95% compared to 1990 levels, driven by the efforts of developed countries to reduce their GHG emissions to a similar degree. The Council's key tool is the European Union Emissions Trading System (EU ETS), which was launched in 2005. The EU ETS is now in its third phase, running from 2013 to 2020. Today, emission allowances (EUAs) are sold at auction, no free allocation of EUAs takes place.

However, Estonia is making use of a derogation (under Article 10c of the revised EU ETS Directive), which allows allocation of an annually decreasing number of free allowances to the country's operating power plants and oil shale companies during the transitional period until 2019. From 2020 onwards there will be no free allocation of EUAs any longer and also the amount of EUAs subject to auctioning by EU governments will be annually decreasing by 1.74%. This will likely increase the price of EUA. By 2030, GHG emissions in the EU shall be reduced by 40% below 1990 levels.

Since 2009, due to economic depression confusing renewable energy push and other poorly planned elements, the EUA price has been much lower than anticipated by the European Commission (Commission). Thus, following the Commission's proposals and the voting in the European Parliament (Parliament), there will be intervention on the back-loading of 900 million EUAs in 2013–2016 to increase the EAU price in the short term. It is believed that this will increase the expected EUA price after 2015 from 12 to 15 EUR/t [14]. The reference scenario foresees that the price of CO_2 will be 35 EUR/t in 2030 and 100 EUR/t in 2050 [15].

Thus, there is a push to establish an economically reasonable price of EUA. At the same time, the EU climate policy will inevitably be continuously dependent on global policies and the EU's ability to bear the related costs. Hence, some uncertainty about the future CO_2 prices will remain.

3.2.2. National taxation

Estonia has a complicated system of environmental charges and fines with a relatively high level of costs to industry [16]. Part of the charges is related to environmental impacts such as SOx, NOx and particles emissions to air, disposal of oil shale processing water, disposal of mining water, depositing of mining residue (limestone), oil shale processing waste (semi-coke) and oil shale ash. The other part is resource charges (mining royalty), which are calculated on the basis of each ton of oil shale reserve used. Table 1 provides environmental charges rates and cost per ton of shale oil produced based on VKG's data at 2013 rates, and environmental charges rates and cost per ton of shale oil proposed by the Ministry of the Environment for the year 2015.

The Estonian government (the government) established mining royalty rates and mining water disposal charges for 2015, but these were declared invalid by the Estonian Supreme Court on 16.12.2013 (case 3-4-1-27-13) as unconstitutional. Thus, the current rates and charges are those established by the government earlier for 2013 and there was foreseen a 5% annual increase of rates until 2015. The rates for the post-2015 period included a 2.5% annual increase until 2020 and from then onwards a 5% annual increase until 2025. The new government agreed on setting ad valorem mining royalties but as of early 2015, there were no public figures available yet.

This study reveals that shale oil production accounts for 87% of VKG's environmental charges costs because oil products of its subsidiary, VKG Oil, make up just this much of the total revenue of VKG's oil shale production value chain (oil, power, heat).

Table 1. Environmental charges rates and cost per ton of shale oil in Estonia in 2013 and 2015, EUR/t

Type of environmental charge	2013 charges rates	2013 cost per t of shale oil	ME proposed 2015 charges rates	ME proposed 2015 cost per t of shale oil
Mining royalty	1.39	14.6	2.4*	21.0
Charge for mining waste disposal	1.09	3.1	1.09	3.1
Charge for mining water disposal	49.7***	0.76	76.69*	1.1
Charge for oil shale ash depositing	2.07	7.0	2.98	10.2
Charge for SO_2 emission to atmosphere**	86.08	4.7	145.46	6.8
Charge for NO_2 emission to atmosphere**	101.10		122.32	
Charge for particles emission to atmosphere	86.5		146	
Total		30.2		42.2

* – rates declared invalid by the Supreme Court;
** – coefficient 1.5 if emitted by oil shale companies in Kiviõli and Kohtla-Järve cities;
*** – EUR/1000 m^3;
ME – Ministry of the Environment.

In international resource taxation comparison all taxes borne by producer related to production are compared to earnings of a mining operation, thus arriving at total tax rate [17], average government take [18] or average effective tax rate [19]. Estonian taxation or environmental charges per ton of mined oil shale are inflexible, being thus very different from ad valorem royalties. Regarding mining waste, mining water, oil shale ash and most atmospheric emissions (with the exception of SO_2), there are currently no good technical or economic solutions to reduce the quantities generated. Thus, all environmental charges are fixed on the basis of the cost per unit of kerogen oil produced.

Carried out by order of the Estonian Association of Mining Enterprises, Ernst & Young Baltic AS showed in its study that while the international total mining tax rate (TTR) in 2010 was 39%, as found by PricewaterhouseCoopers (PWC) [17], then Estonia's corresponding rate for oil shale processing in 2011 was 62% and, given the aggressive increase of the rate, would have reached 83% by 2015 [16]. In 2014, the TTR for VKG was around 68% at the oil price of 105 USD/bbl. For Canadian Alberta oil sands, the average government take in 2010 was 67%, with a high degree of certainty [18]. It is important to note that also conventional oil projects are highly diverse, ranging from mature onshore fields to deep offshore wells in adverse climatic conditions and from minor fields with short economic production life to major fields producing constant flows for decades. Also, all projects have dynamic breakeven cost over their lifetime. given actual production and cost uncertainties over the lifetime of a project. Added to this are highly variable government fiscal regimes ranging from simple royalty system to production sharing, concessions and other contractual arrangements such as investment uplift or loss carryforward [20]. Thus, calculating the government take requires a deep understanding of the subject and is just as dynamic as full cycle breakeven prices.

Globally, royalty rates are generally set from 5 to 25%, but most are nearer 10 to 15% of production [21]. Global TTR in upstream oil production according to four studies quoted by Agalliu [18] varies from 18.5 to 98%, but the average stands around 50%. Government take in the U.S. is from 47 to 56%. A higher take is possible in areas of lower production cost or production fields with long production life and carried capital expenses such as some Arabian and North Sea fields.

An additional cost for the producer, VKG, arises from the fact that due to the fixed allocation of oil shale resource, the company has to purchase 0.8 million t of oil shale from another producer, Eesti Energia. The latter, however, sells oil shale at a very high price, 30 EUR/t, considering that the production cost at the new Ojamaa mine is 19 EUR/t. This means an extra cost of approximately 10 million EUR per year for VKG. With the reduction of oil price in late 2014, the processing capacity that required purchasing oil shale has been laid aside, which in turn resulted in the loss of 200 jobs.

Johnston [22] observes: “More realistic risks include such things as creeping nationalization through expanding taxes, progressive labor legislation, or price controls.” The investigator also states: “Policy shifts constitute the most prevalent and immediate risks that confront industry. These include changes in government a fluctuating tax laws. In some countries, the rate of change is excessive. Democracies, for example, have a habit of making changes that affect business community nearly as often as elections are held.”

The risk related to taxation is oil shale sector governance competence. Currently the oil shale sector taxation is governed and regulated by the Ministry of the Environment, in whose analyses, however, total state revenues and benefits in the long term have not been taken into account. The National Audit Office (NAO) has suggested that analysis of oil shale utilization in terms of state revenue should be continuously performed, considering that by 2016 oil production should significantly increase compared to 2014. According to NAO, to reach the goals set in the oil shale sector, the new National Development Plan of the Energy Sector and the National Development Plan for Utilization of Oil Shale should lay down the principles of taxation of oil shale utilization and bases for changing the taxes [23].

3.2.3. National and EU regulations

Besides the EU’s charge for CO_2 emission and national taxation, both the EU and national institutions have set additional regulatory requirements for the industry, such as maximum allowed SO_2 emission levels, requirements laid down in environmental permits, and waste depositing requirements, which all means further capital cost. While SO_2 emission and waste depositing requirements are well known for a short term, there is a possibility that the requirement for emitting SO_2 of very high purity only will be established, incurring a potential capital cost on the industry to the amount of 100–150 million EUR per year.

3.2.4. Oil pricing

Having been volatile during the period of 2001–10, oil prices reached a certain plateau and stabilized at 100 USD/bbl in 2010–14. If oil prices increase at inflation rate and in lack of major supply or demand shocks, there seems to be strategically some balance between increase in demand by emerging economies and increase of supply from non-conventional oil sources [1]. However, if there are major macroeconomic shocks, there could be a sharp downward adjustment as witnessed in 2008–09. In 2015, such a shock triggered by the slowdown of Chinese economy and increased oil supply was present.

A highly relevant factor is that in order to satisfy bank loan terms shale oil producers need to sell part of their production at forward prices, often not capturing revenues from high market price or having defense from short-term price declines. For example, EE stated in its 2012 annual report that the average price without forward contracts for 2012 was 480 EUR/t (99.2 USD/bbl), but with forward contracts 411 EUR/t and for the year 2013, 67% of production was covered by forward contracts [24].

3.2.5. Shale oil product risk

There is a substantial difference in pricing between crude oil and heavy fuel oil with 1% sulphur content, which is the actual shale oil pricing reference. This difference is called crack spread and it varied in the period of 31.01.2013–31.01.2014 from 71.8 to 163 USD/t. This means that when Brent crude oil price was 790 USD/t, then that of heavy fuel oil was 626 USD/t, thus the perception that high oil prices necessarily result in higher revenues for shale oil producers is not always true. Indeed, the correlation between the two values for the above-mentioned period was calculated by the author to be 0.767.

Another product risk arises from the EU Directive on the sulphur content in marine fuels (Directive 1999/32/EC), which aims at reducing SOx emissions from maritime transport by limiting the sulphur content of marine fuels in environmentally protected areas, such as the Baltic Sea and the North Sea, from the current 1% to 0.1% from January 2015 and that of all marine fuels to 0.5%, according to Annex VI of the International Convention for the Prevention of Pollution from Ships. The effect of the Directive on the use of shale oil is difficult to assess, but it will certainly decrease SO's competitiveness as a marine fuel and/or require further investments, considering its current 0.8% sulphur content.

3.2.6. Currency exchange rate

Pricing of oil and heavy oils is carried out in US dollars, but related costs are calculated in euros. Since mid-2014, due to quantitative easing in European monetary policy concurrent with monetary tightening in the U.S., EUR/USD rate decreased from 1.36 to 1.1 by early 2015. This means that in the middle of 2014, 100 USD/bbl was equivalent to 73.5 EUR/bbl but in early 2015, with the exchange rate of 1.1 EUR/USD, 64 USD/bbl was equivalent to 58 EUR/bbl instead of 47 EUR/bbl, i.e. the amount it would have been at the EUR/USD exchange rate of 1.36. However, close to parity is historically low exchange rate and the average for the 2005–15 period was around 1.25.

4. Analysis and results

4.1. Analysis model

Analysis of different quantifiable risks was carried out on the basis of VKG's actual financial data, which were calibrated with the 2010–13 actual annual public financial data of the company and shale oil price calculations made by Siirde [25]. The current analysis model also employed nonpublic information regarding the free allocation of EUAs, and emissions. The author participated in the design of and data preparation for Ernst & Young Baltic AS 2014 study "Macroeconomic effects of oil shale sector policies", one of the key scenarios of which included similar assumptions of capital expenditure.

4.2. Scenarios until 2030

Table 2 presents scenario assumptions and names. National taxation rate means total tax rate. The assumption of a high or very high TTR suggests its linear, 3 or 5% rise per annum by 2020, independent of oil prices. Moderate TTR would assume its accommodation to oil price. The assumption for CO_2 price would signify its linear rise to 20 EUR/t by 2020 and staying at that level. In case of the high CO_2 price scenario the price is assumed to increase linearly to 50 EUR/t by 2030.

Table 2. Scenario assumptions and names

	National taxation and charges		
CO_2 price	TTR moderate, 65%	TTR high, 80%	TTR very high, 100%
50 EUR/t	Development50	Green Policy50	Resource nationalism50
20 EUR/t	Development20	Green Policy20	Resource nationalism20

The scenarios would all take effect gradually and realize by 2030. Due to the low reliability of long-term price predictions it is not practical to foresee any changes after 2030, also in view of the fact that the current legally binding EU energy and CO_2 abatement policies will be in place until 2030.

A key element regarding capital expenditure is the necessity to replace the aging oil and power production units and other infrastructure with efficient and ecological equipment, thus increasing capital cost. All scenarios foresee the same investments in production, meaning equal capital costs. Currently investments are being made in the construction of Petroter II and III units, upgrading of power generation units and building of a new lime production unit. Future investments will include those in the retrofitting of obsolete Kiviter oil production units, construction of new defenolation equipment, new boilers, novel integrated desulphurization (NID) units for flue gases purification and a new storage tank system, upgrading of the power grid, establishing of a new ash deposit, etc. In 2017, a new, Petroter IV unit is planned to construct to replace part of the Kiviter capacity, which means that by 2020, about 66% of oil will be produced from new, more efficient Petroter units. A further major investment, to the amount of approximately 150 million EUR, will be made in 2023–26 in the construction of a new underground mine in Sonda.

4.3. Results

Results of the modeling of four scenarios are presented in Table 3 and shown in Figure 4. It should be noted that for commercial confidentiality reasons, not all details concerning VKG's business have been publicized. This is mostly because VKG is an integrated company consisting of eight different production units and therefore, costs, investments and revenues of those units that are not related to shale oil production (transportation, electric grid, construction blocks production, etc.) have been excluded from the current analysis.

Even more relevant than the average breakeven cost of SO over a certain period of time are trends of different scenarios. If the trend is towards continuously increasing production cost of SO with no certainty about the increase of global crude oil price, it is apparently a loss-making perspective. Thus only a low CO_2 price and a moderate or low tax rate would allow the breakeven price that will not necessarily lead to an unsustainable outcome. The scenario of a continuously increasing CO_2 price or increasing taxation will increase the breakeven cost, being thus unsustainable.

Table 3. Average full cycle breakeven shale oil production cost in 2015–2030, USD/bbl

	National taxation and charges		
CO_2 price	Moderate TTR, 65%	High TTR, 80%	Very high TTR, 100%
50 EUR/t	86.7	87.4	91.4
20 EUR/t	84.3	85.6	87.7

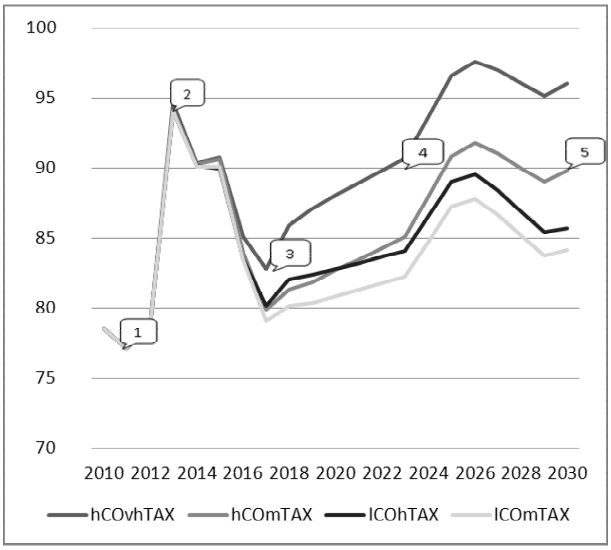

Fig. 4. Full cycle breakeven cost of VKG shale oil in 4 scenarios.

The numbers at the curves in Figure 4 refer to the following:
1 – higher production cost in 2010 due to the increased capital costs of construction of Petroter I unit (around 80 million EUR), with production launched gradually in 2011–12, as well as the increased cost of oil shale purchased from EE;
2 – the effect of a rapid increase in the price of purchased oil shale due to the increase of the oil shale selling price of EE and the higher cost of own-produced oil shale; the effect of high capital expenditure on the operation of the new mine, and of other investments without the increase of production in 2013; the effect of the rise of environmental charges;
3 – the effect of launching Petroter II and III units and other investments in production, leading to a decrease in full cycle breakeven cost; reduced total investment and reduced maintenance per new production unit;
4 – the effect of investment in the new Sonda mine (around 150 million EUR), the higher oil shale cost due to the longer transportation distance (20 km on rail compared to the 12 km on the conveyor belt);
5 – the effect of a higher CO_2 price coupled with a higher CO_2 deficit (the need to purchase more units from the market); higher maintenance cost of aging Petroter units.

One has to draw attention to the effect the inflexible system of allocation of the annual mining quota has on VKG, making the company purchase oil shale from EE at prices above 30 EUR/t, while for EE, the cost of mining oil shale from old mines is 13 EUR/t and from the new Ojamaa mine, 19 EUR/t. On condition that VKG uses up all of its own oil shale resource of 4.9 million t instead of the current quota of 2.8 million t, the company would save 21 million EUR annually and the breakeven price of oil would be reduced from 105 to 97 USD/bbl. In the reduced oil price environment in late 2014–early 2015, VKG had to shut down the capacity for which oil shale for processing had to be bought from EE. This, coupled with the reduced labour force of 200, decreased investments and also significantly reduced workers compensation costs. However, as at the time of writing this paper, VKG's Annual Report 2015 data were not available yet, which would have enabled the author to assess the impact of the reduced oil price on the company as a whole, then only a rough estimation of this impact is presented here (see Table 4). Though, it should be mentioned that 2015 saw a major investment in the construction of Petroter III unit, which was launched and started to yield revenue in the 2nd half of 2015. However, running on a very low capital expenditure in 2016–19 would be possible only with the relatively new equipment and only for a few years, after which the maintenance costs will inevitably rise. Obviously, in crisis mode, there will be no return on investment and all costs will be minimized, leading eventually to the closure of Kiviter processing units. However, the reduction of costs in response to market conditions will unavoidably realize with a certain delay.

Table 4. Rough estimation of the effect of crisis-mode oil cost reduction on breakeven cost

	2015	2016	2017	2018	2019
Breakeven oil cost, USD/bbl	66	52	52	53	54

It is possible to say that future oil prices will increase sufficiently enough to upset any cost increases in SO breakeven price, given concerns over the future supply and increasing non-OECD demand. However, it can also be claimed that increasing unconventional OECD demand, fiscally driven OPEC supply [26] and demand decrease with macroeconomic setbacks [27] will decrease the price. That happened in late 2014. Indeed, there are no credible long-term oil price projections, but a large number of past long-term ones that have ended up being erroneous (see Fig. 5).

Analysis by Yergin [29] correctly shows that market prices change substantially only in combination of both supply- and demand-driven factors. Given the large multitude of both factors in different directions, any argument over the necessarily lower or higher real long-term oil prices are highly speculative.

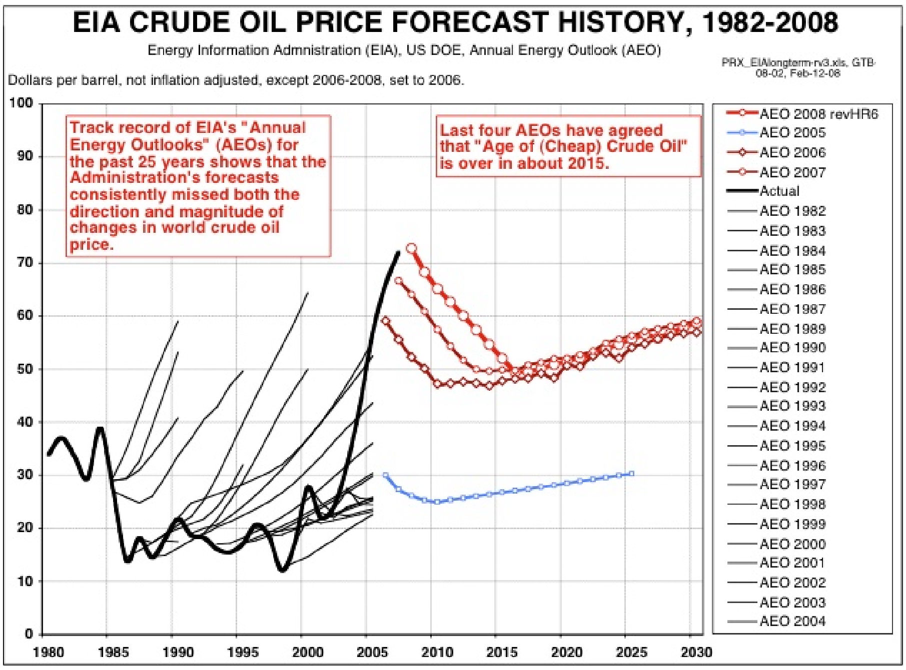

Fig. 5. US Energy Information Agency (EIA) oil price forecasts 1982–2008 [28].

5. Conclusions

Utilization of mineral resources is economically dependent on deposit location, resource quality, mining technology and cost, processing technology and cost, and national regulatory and fiscal regime issues. In case of Estonian oil shale the location, resource quality and mining and processing technology are favourable, as well as the skills level of the personnel may be considered excellent due to experience acquired during the continuous development of the resource for 100 years. However, the requirements of EU and national regulations, as well as the national fiscal regime have created a situation where shale oil production is not economically sustainable without high or increasing oil prices.

The current study shows that the full cycle breakeven cost of Estonian shale oil for producer employing new facilities is in the range of 100–110 USD/bbl for the period of 2015–30. Estonian shale oil producers, with the total capacity of 30 000 barrels per day, are nondiversified minor businesses at high risk regarding oil prices and other industry-related factors. Further analysis of the prospects of the industry for survival during the short- or medium-term period of oil price below 90 USD/bbl will be required.

However, considering the significant unavoidable capital expenditure to replace capacity, and the EU CO_2 policy, which can only mildly be influenced by the Estonian government, it is obvious that Estonia needs to review its oil shale sector's regulatory and taxation system to enable the industry to sustain in the long term.

The current study demonstrated the economic feasibility of shale oil development in Estonia. A key to the industry's economic sustainability is a friendly and long-term stable regulatory environment to allow large-scale investments to be made to earn a competitive return on them.

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Presented by E. Reinsalu
Received May 28, 2015