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Accelerating the three dimensions of E&P clockspeed – A novel strategy for optimizing utility in the Oil & Gas industry

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ABSTRACT

As the global Oil & Gas Industry enters its third, late lifecycle stage (outlined in the introduction of this study), new strategies and conceptual tools are needed to postpone – or reverse – the decline of the E&P industry. The problem is this: the late lifecycle is principally heralded by limited supply due to finite hydrocarbon reserves, while energy demand soars as world population and the global economy continue to grow. This study therefore proposes a framework through which an E&P company can critically assess its capability in accelerating lag-time between exploration and production. In the first part of this paper (Sections 1–3), the need for a phase-shift toward faster clockspeeds for the Oil & Gas industry is argued to be an important step to close the energy supply gap. In the second part of this paper (Sections 4–6), the strategy concept of clockspeed acceleration is further elaborated and optimization methods for the three principal dimensions of E&P clockspeed acceleration are discussed. The three *Clockspeed Accelerators*™ are: workflow speed, improvement rate of Uncertainty Mitigation and accrual speed of portfolio value. The third part of this paper (Sections 7–11) presents the empirical analysis of E&P clockspeed performance for two peer groups (IOC supermajors and public private partnership NOCs) comprising six companies each. The acceleration of E&P clockspeed can help to optimize production levels of conventional and unconventional oil, and includes diversification strategies that replace non-renewables with renewables. In summary, E&P Clockspeed Accelerators provide the gearshift instruments that enable the energy industry to better meet the required demand/supply ratios. The results of this study translate into the following deliverables for practical use by Oil & Gas professionals:

- insight into the concept of clockspeed in E&P industry setting,
- use of *Clockspeed Accelerators*™ as gearshift lever tools for monitoring and directing E&P clockspeed,
- a template for benchmarking and scaling the cardinal axes of E&P *Clockspeed Accelerators*™ for companies in time-series analysis and cross-sectional analysis,
- insight in the critical drivers of E&P clockspeed acceleration based on the companies studied,
- a set of recommendations to support and speed up the optimization of the individual *Clockspeed Accelerators*™ for Oil & Gas companies.

1. Introduction

The Oil & Gas industry has succeeded in carefully matching its supply capacity with the demand from the global consumer markets for well over a century. Reaching the appropriate production levels has always required the rapid deployment of new and current technologies to find – and develop for production – more hydrocarbon reserves. But in the 21st century, production optimization technology will become even more critical as the easy oil is gone and demand keeps rising. Oil & Gas cater for 63% of the world's primary energy demand [1]. The remainder is supplied for by coal, nuclear and renewable sources.

The International Energy Agency [2] has estimated the cumulative investment, required worldwide for developing new Oil & Gas supplies over the period 2005–2030, at nearly 8.5 trillion USD. In fact, new technology and new process solutions need to be developed faster and more urgently than cash can generate – the IEA costing rises to 20 trillion USD if including the investment required for developing new electrical power stations, new coal supplies and new bio-fuels. Additionally, the field development lifecycles in the Oil & Gas industry are so long that any investments over the next decade locks in the technology that may remain in use for up to 50 years.

Traditionally, the utility or benefit that the Oil & Gas business expects to derive from investing in the innovation of new products or services tends to let this industry decide they conduct E&P oper-

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ations using proven concepts and proven technology. The need for operational reliability, security of production, and avoidance of downtime over many years of the production lifecycle, all impair the Oil & Gas industry to innovate faster. But we have now arrived at a stage where new solutions are needed ever faster to produce more oil and to replace produced volumes by new discoveries. As the easy oil fields continue to phase out, new fields require more challenging development solutions. This means that the attitude of the E&P industry toward innovation must change, toward stimulating the accelerated development of new technology and toward the faster deployment of such new technology.

To substantiate the increasing demand on technology, the lifecycle of the global petroleum development is best subdivided into three phases (Fig. 1):

- *Early exploration phase (1930–1970):* discovery volumes increased year by year, while annual production capacity grew steadily from less than a billion barrels in 1930 to over 17 billion barrels in 1970. Some of the larger volumetric discoveries from the early exploration phase can still continue to feed 21st century oil production, provided new technology continues to enhance their recovery rates (see later). This is the early lifecycle stage of the Oil & Gas industry.
- *Development plateau phase (1970–2000):* discovery volumes, after peaking in 1964, kept sliding back and could no longer replace annual production since 1990. Overall, between 1970 and 2000 as much oil was produced as discovered, with time-averaged annual production just above 20 billion barrels. Since 1990, a cross-over has occurred between the annualized discovery bell curve and the shifted production bell curve in a point (Fig. 2), marking a situation where the annualized global production volumes began to outpace the discovery of new volumes. This is the mid lifecycle stage.
- *Unconventionals and alternatives phase (2000 till 2050):* in order to meet the short-term projections for oil demand, industry must continue to boost annual production – from 30 billion barrels in 2007 to over 31 billion barrels by 2010. New discoveries of (conventional) oil volumes will not be sufficient to turn up the production decline curve. To meet demand, so-called unconventional oils (e.g., tar sands and gas hydrates) need to be developed. Conventional oil reserves are likely to be fully depleted by about 2050. Meanwhile, global demand for hydrocarbons continues to rise, and price levels may reach the so-called Break Point (see later). This is the advent of the late lifecycle stage.

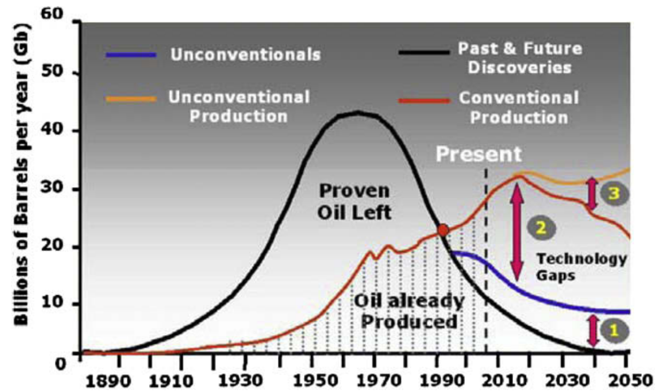

Fig. 2. Technology gaps: oil production of both complex and deeper (offshore) fields requires the development and application of advanced technologies. New reserves need to be added by using (1) new technology to discover new prospects and to allow these reserves to be reported as proven. (2) Production from conventional oil is under duress as remaining reserves are in challenging reservoirs; new technology is needed to maintain production volumes. (3) Production from unconventional reserves also requires deployment of new technology.

Oil production of both complex and deeper (offshore) fields require the development and application of advanced technologies and processes, and the phasing in of new engineers and new leaders. Creative scientists and innovative engineers are needed that can inspire the next generation of petroleum professionals [3]. New reserves need to be added by their efforts using a variety of technological solutions (Fig. 2). These include: (1) new technology deployment to mature reserves such as to be reported as proven; (2) as production from conventional oil is under duress because remaining reserves are in challenging reservoirs, new technology is needed to maintain production and enhance recovery from the remaining proven conventional reserves; and (3) production from

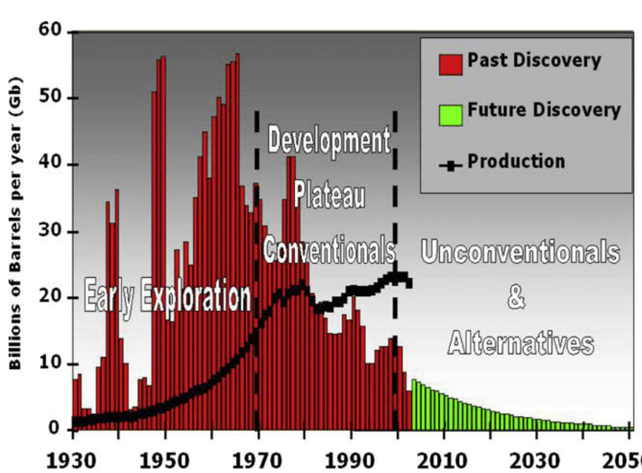

Fig. 1. Three phases in conventional oil business. The majority of conventional oil reserves have been discovered in the 20th century. Production has depleted part of these reserves. In order to be able to maintain sustained production, companies need to replace produced volumes by new discoveries. In the 21st century, the global reserve replacement volume falls behind the production volume (EXXON data).

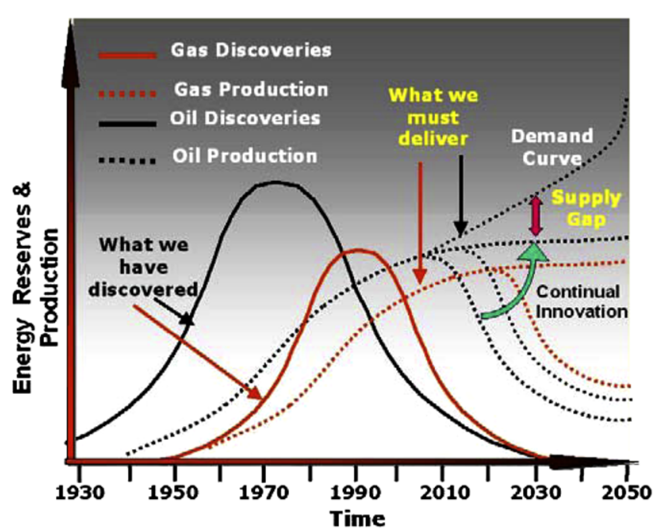

Fig. 3. Energy lifecycle replacement: the energy supply gap (red arrow) that emerges when innovation (green arrow) can no longer extend the production from Oil & Gas fields to match the global demand curve. In reality, the supply gap is likely to be filled by alternative sources – and more efficient usage of – energy. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

unconventional reserves also requires the deployment of additional new technology.

The summary of Fig. 3 shows that the lifecycles of conventional (or traditional) Oil & Gas production near completion in the 21st century. Technology and process improvements already have brought the petroleum industry access to progressively deeper on-shore and – later – offshore resources. When technology and process innovation can no longer extend the production from conventional and unconventional Oil & Gas fields, the new solutions for energy supply must come from alternative energy sources. Price elasticity of Oil & Gas reaches the high end, which means that alternative energy sources can count on a bigger market share, while fossil energy consumption may slow down due to leaner use. The market itself will continue to steer and gear the energy industry to a proper balance between energy prices, essentially from the diversification of energy supply options, directed by supply and demand ratios (see next section).

2. Utility principles and oil pricing

Although current demand/supply ratios suggest that the marginal utility of the fossil fuel volumes produced is growing, overall utility of production volumes will eventually decline if total fossil fuel consumption begins to slow down after so-called Break Point [4]. The Oil & Gas industry interacts with the market to establish an optimum price per unit fuel volume. The consumer is prepared to pay an excess quantity for crude oil when the demand/supply ratio exceeds 1 and under the assumption that affordable and convenient alternatives are absent. The ratio is defined here as:

$$R = D/S \tag{1}$$

with $R = 1$ indicating a perfect match between supply and demand, $0 < R < 1$ meaning oversupply (or suppressed demand), and $1 > R > \infty$ meaning under-supply (or unbalanced, rising demand). Price hikes are not instantaneously, but the response is based on long-term real trends or expectations about R.

The excess amount, or price demand elasticity, sets the market price (P) for crude oil [5]:

$$P = C/[(1 - 1/\eta)] \tag{2}$$

where $1 < \eta > \infty$ represents the absolute value of the price demand elasticity and C the cost to produce one barrel of crude oil. The elasticity factor $1/\eta$ ranges between 0 and 1, and climbs away from 0 when short supply ($R >> 1$) gives larger profit margins for industry. The oil price will only rise further until the consumer finds the point of the optimum purchase price is passed in favor of alternative choices for energy solutions. The so-called Break Point will then be neared and occurs when oil consumption start to slow down in response to further price hikes.

Fig. 4a plots the schematic relationship between R and P. The assumption that, if R is perfectly balanced at anyone time, P tends to remain stable is a simplification, because refinery capacity, spare production capacity, and geopolitical tensions also add to price volatility [6]. Nonetheless, changes in R affect the consumer price P of crude oil. The associated 'marginal utility' from an industry perspective, or 'incremental change in utility' – scaled here by the rate of change in the oil price (dP/dR) – is plotted in Fig. 4b.

To prevent the early occurrence and to delay the passage of the optimum purchase price, it is in the interest of the Oil & Gas industry to manage the oil demand/supply ratio such that the overall utility remains attractive and profitable, otherwise overall utility risks declining faster than reserves. The delays and postponement in the development of supplies, supply disruptions (notably Nigeria and Venezuela, each falling 1 million barrels per day behind peak capacity, and Irak still being below pre-invasion levels) combined with increased production costs, geopolitical tension and dwindling swing capacity feed into a scenario that drives prices up to CERA's 120–130 USD Break Point level [4,7]. Other economic models show that a 50% price hike in crude oil results in a GDP drop by about 0.5% [6], even before the Break Point is reached. The Break Point scenario of CERA predicts an upper limit of about 150 USD per barrel. The Break Point or Break Zone envisions that global decision-makers will increasingly provide incentives for the speedy development of innovative energy solutions with simultaneous adoption of energy conservation policies that will result in a decreased need for production increases in oil-exporting countries.

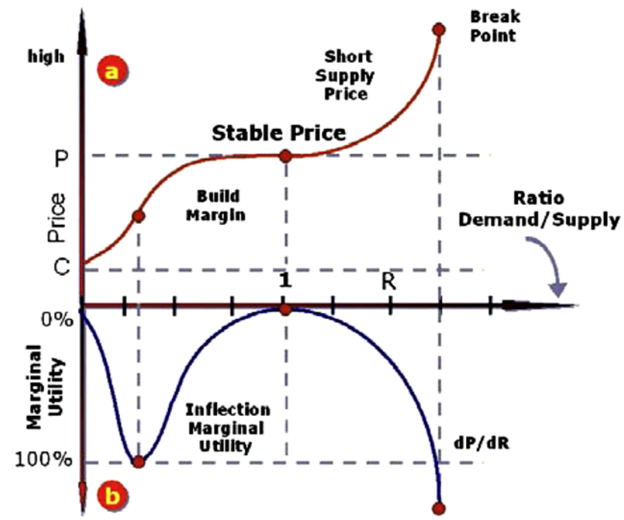

Fig. 4. (a) Price per barrel of oil vs. demand/supply ratio. Price remains relatively stable when R stays close to unity. The energy supply gap will lead to higher prices. (b) Marginal utility will be close to zero in the stable region, but rises again when short supply pushes up prices.

Optimizing overall utility of the petroleum industry requires planning production levels such that they can continue to meet demand/supply ratios. A doubling in oil price over periods of less than 5 years results in a 2–9% drop in OECD oil consumption, while non-OPEC oil production tends to grow 4% when oil prices double (postulated by Chicago University Nobel Laureate Gary Becker on 2008 weblog). Independent econometric models of oil price shocks suggest that the initial rises in consumer prices could dissipate within a decade or less when technological advances help to absorb the effects of higher fuel costs [8].

Clearly, overall utility of crude oil will tend to decline within a decade if the total fossil fuel consumption continues to slow down over a similar period, mostly due to four major factors:

- Demand slows when economic growth stagnates or declines.
- Demand slows when the utility of any alternative energy sources becomes better than that of Oil & Gas. The oil price will rise only until the consumer finds the point of the optimum purchase price is passed in favor of alternative choices for energy solutions.
- Demand slows further when energy converters (engines, power plants, appliances and lamps) continue to improve their energy efficiency.
- Demand slows still further when consumer behavior and policy rules lead to more conscious use of energy and results in real energy conservation (no longer leaving lamps and heating on when home and offices are not used).

Although the marginal utility for Oil & Gas companies increases when R grows beyond unity, to ensure that the overall utility in the E&P industry will not enter into decline, supply and demand must be brought into equilibrium so that P stays below Break Point (Fig. 4a and b). The interest of the Oil & Gas industry is best served by managing the demand/supply ratio such that these do not reach beyond price elasticity: overall utility must remain profitable for both the business and the consumer. This means production levels must meet consumer needs in the medium and long-term future, otherwise overall utility will eventually decline. Thus measures need to be taken to prevent or delay the occurrence of Break Point (or Break Zone), as predicted by the CERA [4] scenario.

One pathway for the E&P industry is to optimize overall utility by developing a sustainable capacity to match supply and demand on the short and medium-term through the acceleration of E&P clockspeed. Although there are studies that inventory the effect of clockspeed in different industries (e.g., [9], a systematic approach that defines Clockspeed Accelerators for the Oil & Gas industry is first undertaken here. Clockspeed Accelerators provide the gearshift instruments that enable the energy industry to better keep the demand and supply in controlled equilibrium. The E&P Clockspeed Accelerators are outlined below; these can be used as managerial gear shift levers, and drivers for their optimization are pinpointed.

3. Clockspeed acceleration – faster workflow and decisions, reducing uncertainty, and maximizing asset value

Clockspeed in computers is defined as the number of pulses that can be handled by an oscillator that sets the tempo for the processor – notably, high frequency performance is only effective when a fast memory system is included in the CPU [10]. Clockspeed in humans and animals relates stimulus duration and pulses received to decision-making and behavioral speeds [11]. Industry clockspeed is a concept for the pacing of dynamic business strategies [12,13], where different industries move at different clockspeeds, as compared to one another and to the global business environment. Examples of indicators of clockspeed are: rate of change in organizational structures, and frequency of new product launches and of new technology adoptions [12]. Fine's industry clockspeed can be best translated as the velocity of change in the external business environment that sets the pace for a firm's internal operations [14]. More specifically, clockspeed puts a timer on the well-known concept of strategic transformations. If companies move at too slow a clockspeed, they run the risk to enter into strategic drift and they become disconnected from the competitively changing business environment (Fig. 5).

Strategy initiatives are needed in individual companies to ensure that their speed of strategic change is not too slow as compared to the rest of the business league and to avoid a big bang or failure. Aversion to risk generally lowers industry clockspeed and results in a slower absorption of organizational innovation and new technology, according to Noke et al. [14]. Their Twister case study affirmed the need to seek solutions for accelerating innovation speed in the traditionally slow clockspeed Oil & Gas industry.

Effective clockspeed strategies can speed up production levels to extend longevity of the Oil & Gas industry. Three principal dimensions of E&P clockspeed acceleration are introduced here, see Fig. 6. These dimensions are: (1) speeding up the workflow for decision-making, (2) mitigating project risk by quantifying uncertainty, risk and opportunity in the workflow; this mitigates project delays and downtime, and (3) adding faster value to assets – at project level and portfolio level – during project execution. These Clockspeed Accelerators are discussed in some detail below.

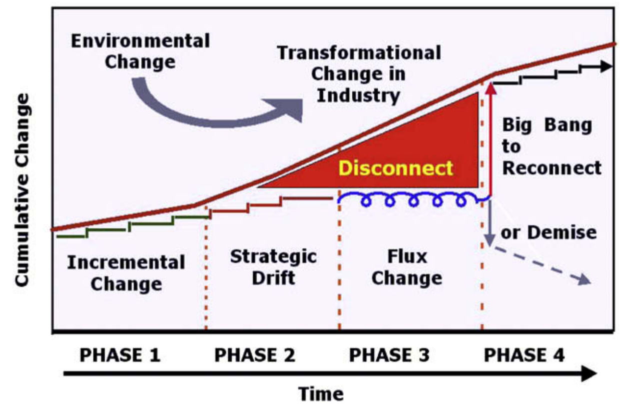

Fig. 5. The solid red curve represents 'best practice' for a specific industry segment studied. Individual companies that cannot keep up with the speed of transformational change in the industry segment will disconnect and run the risk to fail. Four phases of increasing disconnect with the transformational change are indicated. Only a major change (i.e., 'Big Bang') can safe a company that has erred for too long in strategic flux. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

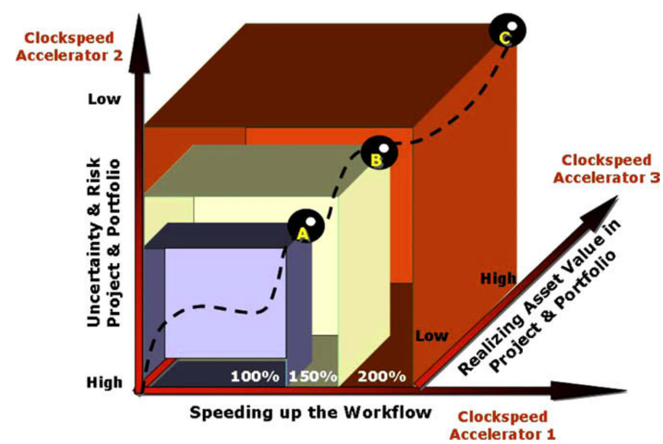

Fig. 6. The E&P clockspeed can improve in three dimensions: (1) speeding up the field development lifecycle, (2) enhancing quality of risk mitigation and uncertainty control, and (3) optimizing the value adding efficiency. The improvement of 'best practice' in all three dimensions helps to accelerate a suboptimum clockspeed (Case A), to an improved clockspeed (Case B), in pursuit of the optimum state (Case C).

4. Clockspeed Accelerator 1: speeding up the workflow towards real-time asset management

A first option for clockspeed acceleration is further efficiency improvement (or optimization) by speeding up the workflow for decision-making in concession applications, exploration, appraisal, development planning, project execution, production and expediting field abandonment. Companies now resort to full-lifecycle development plans that focus on maximizing the net present value of a reservoir through effective reservoir management. The basic architecture of the 'best practice' E&P workflow is concisely described in Appendix A.

Ultimately, most petroleum business decisions for project gate-stages are based on technological arguments, where people, technology, and processes must be aligned to speed up workflow rates (Fig. 7). Effective workflow practice can shorten the completion of project stages to months instead of years, days instead of weeks, and seconds instead of minutes.

The workflow spiral needs to speed up to effectuate faster progress in field development projects and reserve maturation; here are some suggestions for each phase in the field development pro-

Fig. 7. Corporate performance is fuelled by effective knowledge enhancement integrating professional expertise, technology tools, and processes in an ever faster workflow. Organizational Learning helps speeding up the workflow spiral, while critical decisions are made on business risks and opportunities. Smart workflow architecture helps to organize the decision-making process (from Ref. [16]).

cess (the associated gate-stage stops are illustrated in Fig. A1, Appendix A):

4.1. Pre-concession and concession work

The early entry into new concessions becomes more and more important as the number of prospects is limited. IOCs now must learn to respect the finesses of political complexities and cultural differences to increase their chances to gain access to NOC resources [15]. NOCs have become the dominant players on the world market for crude oil, so that E&P clockspeed is now affected more by geopolitical agendas than by technology, especially when considering pre-concession and concession work. IOCs and NOCs must jointly work to prevent the occurrence of Break Point otherwise OECD governments will progressively intervene to ensure stable energy supply for the future.

4.2. Exploration and drilling

Faster and more cost-effective exploration reduces the average lead time from licence award to discovery below 3 years. Remote sensing techniques of higher resolution allow the detection of hydrocarbons from slicks and seepage. Seismic exploration costs have come down in real terms and the velocity migration is becoming more accurate.

4.3. Appraisal

Within the subsurface evaluation and appraisal workflow section (see Appendix A for detailed workflow schedule in Oil & Gas business), several workflow screens exist – these are located between formal decision gate stops (Fig. 8). Go/No-Go decisions are not taken at the workflow screens and iterative exchange of knowledge is useful and can occur as frequently as needed within the overall workflow section. Reservoir characterization utilizes field information (seismic, wells, geochemistry, petro-physical interpretation, etc.) to describe the reservoir and create a reservoir model. The workflow proceeds with a forward simulation of reservoir physics in order to predict reservoir performance with the goal of effectively depleting the reservoir. More accurate delineation of the subsurface reservoir parameters can be realized by faster characterization of the reservoir properties. Faster cycle times and better decisions can be realized through faster integration and faster reiteration of the Seismic Imaging, Stratigraphic Modeling, Reservoir Characterization, and Dynamic Simulation.

Drilling of appraisal wells has become safer and drilling success rates have improved by sophisticated geo-steering techniques. Drill bit position and formation measurement data are relayed to geologic models that alter the bit direction to favorable targets or away from possible hazards. Seabed seismic sensor readings are correlated with reservoir models to determine reservoir charge levels in order to plan production and injection locations with an order-of-magnitude time scale compression.

4.4. Field development planning

Within the Concept Selection workflow section of Development or Facility Planning (see Appendix A), workflow screens can be delineated between exploration well data analysis, production well design and well costing (Fig. 9). Production wells can now be designed with distributed, non-destructive sensors which measure (near hole and inside the producing formation) reservoir parameters such as pressure, temperature, chemistry, and fluid flow rates.

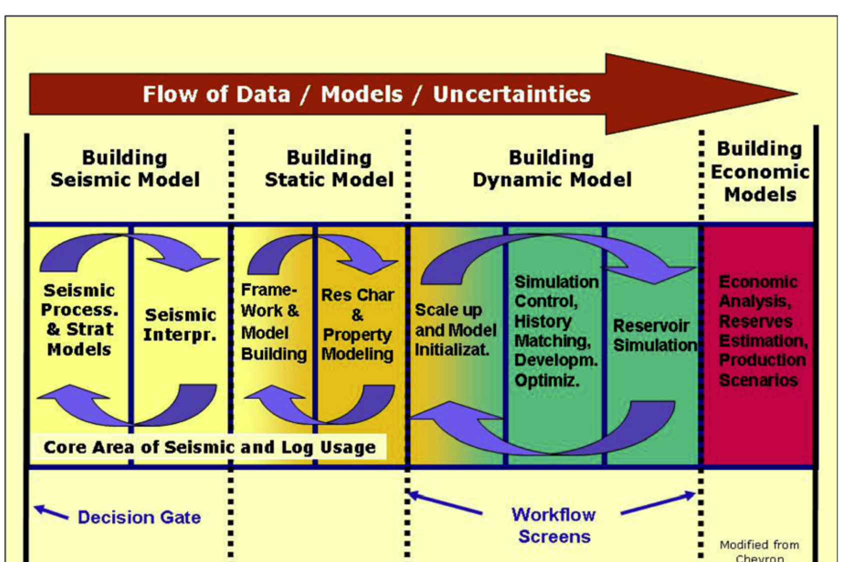

Fig. 8. Workflow subsurface evaluation and economic appraisal. Workflow screens exist between technical specialist units within the Evaluation and Appraisal workflow section. Maximum data sharing is encouraged across the workflow screens and iteration back and forth are frequent (based on Chevron Workflow).

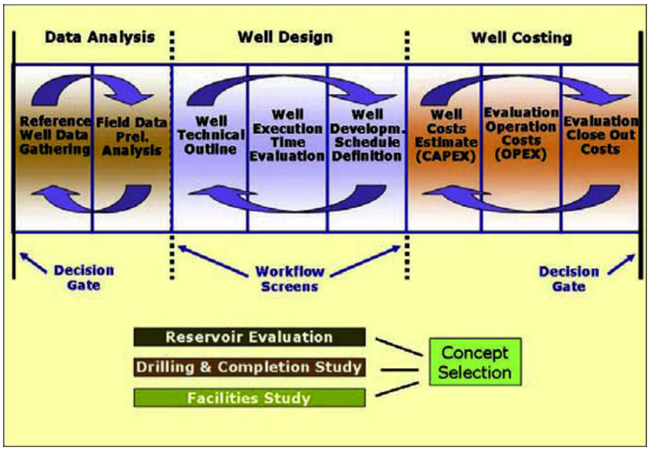

Fig. 9. Workflow in drilling and completion studies: iteration steps within the concept selection workflow section of field development planning, see Fig. A1 (Appendix A).

Sensing components and systems are developed by service companies to optimize sensor activation systems, data processing and storage, and knowledge management concepts and strategies. Service companies develop down-hole sensors with improved quality and reliability and systems for the integration of data from different sources. This enables near real-time analysis and interpretation of well data to monitor reservoir performance to maximize value by proactive reservoir surveillance and well management. Monitoring technologies can soon identify sweep efficiency for stimulating recovery. Well reliability must improve such that a well or group of wells can be maintained in a continuous producing and active state [17]. Well optimization helps to raise existing well performance to higher levels. Surprises in reservoir and facility performance are reduced or eliminated by observing and controlling fluid movement [18]. Modern field development projects include in-situ seismic arrays to allow the frequent acquisition of seismic images of the reservoir. This 4D and full-wave seismic processing and interpretation reduces the difference in scale resolution between seismic and reservoir modeling.

4.5. Project execution

Faster and more cost-effective field development execution reduces the average lead time from discovery to production to 4 years.

4.6. Production

Real-time asset management in digital (rather than mechanical/analog) oil fields allows continual gathering of data and monitoring of the production system [19]. Failed equipment can be detected and replaced rapidly and reduces downtime in production. Real-time asset management optimizes workflow efficiency and minimizes deferred production by rapid remedies and accelerates production optimization, reduces reservoir damage and avoids facility failure [19]. This also reduces lost profit from unscheduled downtime or reliability events, while optimizing the net cash flow. The workflow loops in well optimization revolve in days or weeks, production optimization over months and field optimization over years.

The integration of subsurface software platforms allows collaboration across G&G and reservoir disciplines. The production control room and reservoir simulation and visualization centers are linked up or combined for greater operating efficiency by integrating the work processes between production and reservoir engineers [19]. Digital decision support systems based on subsurface and surface predictive modeling technology enable real-time data management to control the production environment. Operators are realizing significant value from establishing mechanisms for real-time data exchange between drilling wells, production wells and surface facilities. Coupling of models to these systems is beginning to offer the opportunity for real-time reservoir management. New visualization tools facilitate the access to data, interpretations, and models to support and link to Asset Management Teams, to enable improved operating efficiency. The value of information justifies real-time and near real-time integration of all data systems. Formation pressure and temperature readings are collected from across the field, correlated against a reservoir simulation model and down-hole valves in "smart wells" are positioned and regulated to maximize field production. Future focus will be on the analysis and interpretation of well data to monitor reservoir performance to maximize value for water, gas, and steam injected reservoirs.

4.7. EOR methods

Corporate management commonly sets ambitious enhanced recovery targets of 60% for large oil fields, and 80% for gas fields (as suggested by the Norwegian Petroleum Directorate for the Norwegian Continental Shelf area). EOR optimization to raise the existing field performance to higher levels, includes improved modeling capabilities regarding CO_2 injection for EOR. Pressure on CAPEX needs to be mitigated in the operation of mature fields due to increasing maintenance costs, and activities to maintain production in EOR projects and artificial lift (water, steam injection). Technology is required that facilitates the use of CO_2 for EOR. Kyoto prompts to strive for reduced CO_2 emissions, curbing gas flaring and continues to raise criticism on the environmental impact of fossil fuel.

4.8. Abandonment

Effective exit strategies must account for cost of abandonment and address stakeholder concerns about financial and environmental issues. Rapid decommissioning procedures help liberate company resources for new projects.

5. Clockspeed Accelerator 2: mitigating uncertainty and risk in field development projects

Modern field development and production strategies utilize geological uncertainty and risk in the reservoir, and optimize surface designs for recovery while stochastically quantifying economic and portfolio risks and uncertainties (Fig. 10). Decision-making relies on sensitivity analysis to determine which parameters affect most the uncertainty range so that Monte Carlo modeling can focus on multivariate analysis with a limited number of critical parameters [21]. Further real-time integration of field data into reservoir and economic models allows for the early identification of discrepancy between the real and the simulated value creation process [22].

Uncertainty quantification and decision-making processes control how technology generates information for new ventures and investment options. Managing this process requires the ability to quickly identify the key technology and business challenges, their related indicators and available data sources. Petroleum business engineers also need to understand the petroleum sector in its economics, financial and geo-strategic risks and opportunities. They must be able to build their own model of investment analysis taking into account fiscal uncertainties, inflation and financing

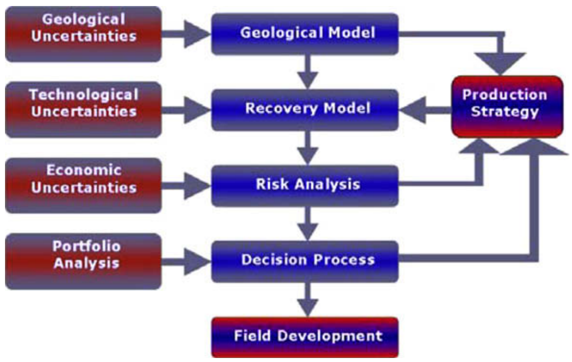

Fig. 10. In the upstream Oil & Gas business, the full field development value is realized by reducing risks and quantifying probabilistic uncertainty to optimize the production strategy options (based on [20]).

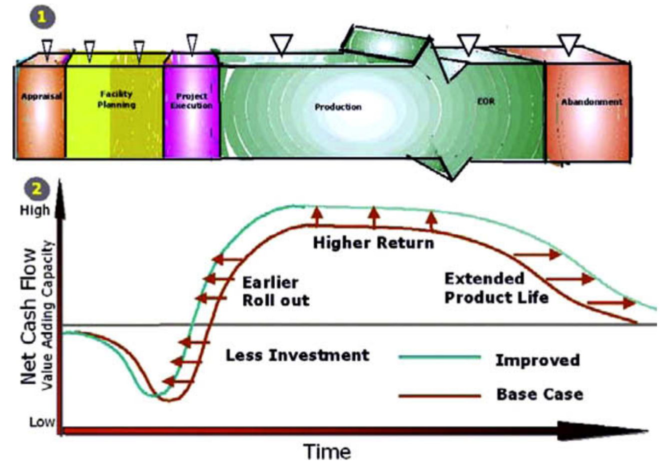

Fig. 11. Upstream Oil & Gas Project lifecycle: full field development value is realized by effective execution of each phase of the project lifecycle (1), which generates cash flow (2) that earns back operating costs once production starts. Starting production earlier and extending EOR contributes to value adding for the company.

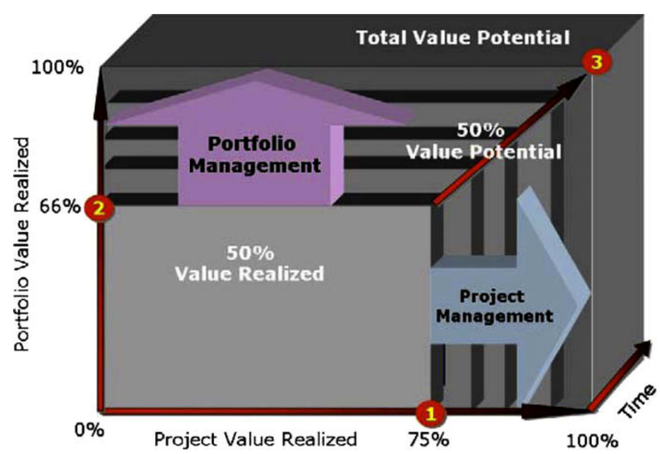

Fig. 12. Effective building of assets results from effective project and effective portfolio management. For example, if field development captures only 75% of the total project value (1), and portfolio value captures only 66% of the total project options value for the company (2), 50% of the business value remains unrealized or needs development over time (3) (based on Microsoft portfolio policy).

tools in order to take informed decisions related to the (re-)development of new as well as aging oil fields.

Strategic risks are related to the optimization of field development project selection and must avoid suboptimization and minimize operational project risks. The primary, operational project risks include: subsurface risks, reservoir risk, risk of loss of Oil & Gas production, upstream installations, offshore catastrophe, and political turmoil. Most Oil & Gas companies rigorously assess and validate project profitability, i.e., NPV potential vs. risk and portfolio strengths. After ensuring that risks and opportunities are balanced at the efficient frontier in the initial project validation, companies hedge their assumed operational project risk by insurance. Insurable operational risks cover all assets and can compensate, at least partially, for future business interruptions and production loss.

The secondary, market and financial risks include: fluctuations in Oil & Gas prices, foreign exchange risk (for nearly all company's operating outside the USD currency zone), and tactical risks that relate to interest rates and derivatives used to hedge commodity and currency risks. Financial risk management must weigh debt-leverage to avoid financial distress and support the company's ability to finance future growth. Financial risk management also must include optimization of the debt portfolio based on expected future corporate cash flow. Most E&P companies employ sophisticated optimization models to manage all these risks.

6. Clockspeed Accelerator 3: faster value adding in portfolio

Value management in the E&P industry concentrates on factors that optimize the EMV and NPV, such as discounted cash flow, recovery factor, and field development time (Fig. 11). Management decisions on the project must stay aligned with the corporate strategy and market drivers. The strategy commonly means maturing "tougher barrels" and increasing reservoir efficiency.

The building of a profitable and sustainable corporate asset portfolio must occur faster and faster to realize full asset value. At the portfolio level, company performance can be monitored through corporate KPIs, P/E ratio, share price, profitability, liquidity, annual growth, reserve replacement ratios, and the balance of risks and opportunities in the portfolio. Company performance therefore is still the result of effective (field development) project management and effective management of the overall portfolio of projects (Fig. 12).

While the drive towards real-time decision-making can bring economic benefits, project phasing is steered by decisions at corporate portfolio level. Different projects arrive at different times at the development proposal gate stop (and resources need to be allocated for future development planning with prioritization of resources based on the corporate alignment of projects).

Asset managers need to quantify for value optimization all the risks and uncertainties, make decisions on, and develop solutions for portfolio optimization. For example: what is the identity of the company – who are we? What is the financial position of the company? What will happen to the company assets in a do-nothing scenario? Where does the company want to go (vision, mission, and goals)? How can the company achieve this (strategy, action plan)? Why is the company better than its competitors? Which portfolio would realize the goals and trade-offs (strategy options, liquidate vs. continuing assets, tools used, project in, project out, and efficient frontier)? What is the projection for the future with the assets kept in the portfolio (near-term, mid-term, and long-term)?

Project optimization runs risk of suboptimization if not contributing to portfolio optimization [23]. Project performance must be monitored and fed into the project portfolio for selecting the most profitable and least risky (future) project options. Project value realization techniques are aimed at closing the strategy-to-performance gap [24]. Multi-asset ownership problem is a special challenge in the Oil & Gas business where trade-offs between individual stakeholders and asset value are put to the test. Capital efficiency must be optimized in all projects. Corporate management must be prepared to invest in the proposed solution to enhance value creation by new production capacity and the application of more cost-effective technology.

7. Benchmarking Clockspeed Accelerators

The E&P industry must strive to perform optimally in all three dimensions of clockspeed acceleration in order to optimize its efficiency. Consequently, the E&P industry can benefit from a method that helps them to benchmark the setting of the three principal Clockspeed Accelerators. This study uses time-series analysis and cross-sectional analysis to rate the relative performance using the three principal E&P Clockspeed Accelerators outlined (in Sections 4–6).

As a first step, 12 representative oil companies were selected from the companies ranked by the Energy Intelligence Group in its annual '*Top 100 Ranking of the World's Oil Companies*' (for details, see Appendix B). The annual benchmark by Energy Intelligence is recognized throughout the industry as the leading source of comparative assessments on the performance of all the world's leading oil companies. The 100 companies examined in the 2008 edition of '*The Energy Intelligence Top 100*' account for 87% of global oil production, 88% of global oil reserves, 73% of global refining capacity and 87% of global refined product sales.

From the PIW global ranking list in Table B1 (Appendix B), a selection was made for comparative clockspeed study of two groups of peer companies: (1) *The IOC Top 6* (supermajors): Exxon, BP, Shell, ConocoPhillips, Chevron, and Total; (2) *The Public Private Partnership NOC Top 6* (PPP NOCs – those NOCs that are only partly privatized): GazProm (50.0023% State), Petrobras (32.2% State), ENI (30% State), Statoil (70.9% State), ONGC (74,14%), and OMV (31.5% State). All these companies are stocklisted and performance data are publicly available in their annual reports. For the 12 companies examined in the present study, 60 annual reports were studied to abstract and compare key performance indicators and trends in their relative clockspeed performance over a 5-year period (2003–2007).

7.1. Clockspeed Accelerator 1

Clockspeed Accelerator 1 is a lever of workflow speed (as outlined in Section 4), which is mainly dependent on the effectiveness of internal cooperation, efficiency of business processes and technology integration. A concise measure of the corporate performance in workflow speed is the productivity, expressed here in terms of corporate net earnings per employee. Fig. 13a graphs the ratio of earnings/employees for the IOC peer group of Top 6 companies; Fig. 13b graphs similar results for the PPP NOC Top 6 peer group. The underlying graphs of Net Income and Number of Employees per company and associated data tables are given in Appendix B.

For the time-series analysis, the trend in the speed of change of the ratio earnings/employees was classified to establish which company lags behind others, as a comparative benchmark of Clockspeed Accelerator 1. The relative performance trend in the time-series analysis was classified as (Fig. 14):

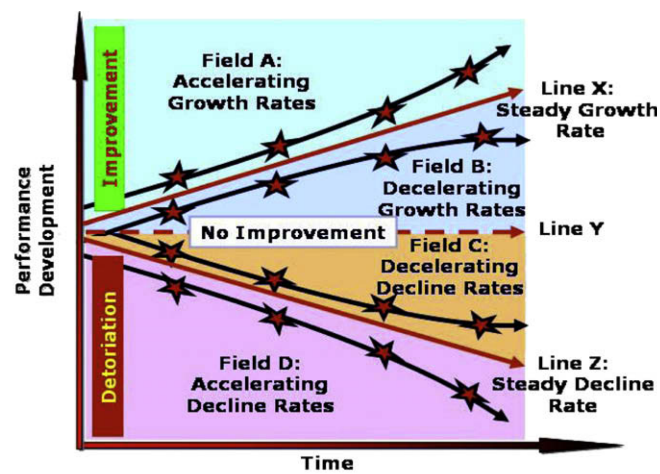

Fig. 14. Classification analysis of time-series for the relative performance of peer group companies. Trends or slopes of lines *X* and *Z* vary, and separate Fields A&B (performance improvement) and C&D (performance detoriation). The trend and best fit for the acceleration (or deceleration) in each field is used to classify the time-series of companies in Tables 1–3. See text.

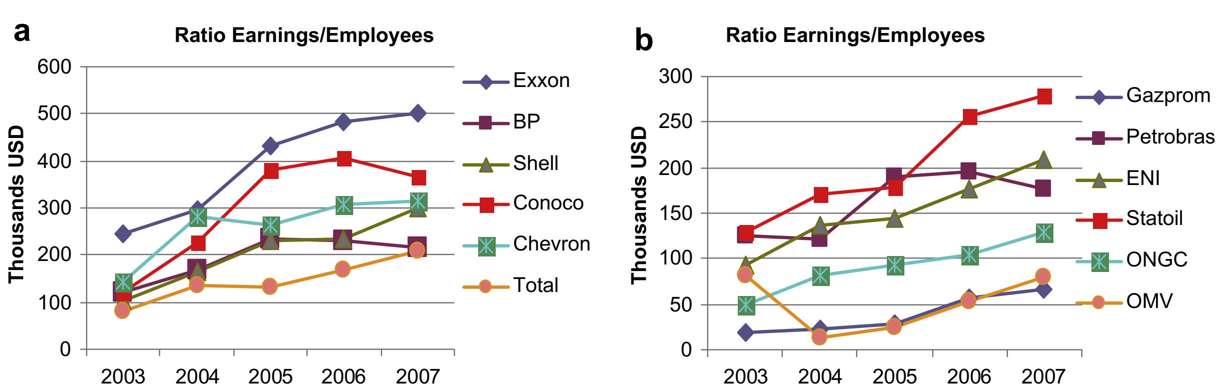

Fig. 13. (a) Net income per employee for the peer group of six IOC supermajors. (b) Net Income per employee for the world's Top 6 peer group of PPP NOCs (all data abstracted from annual reports, and converted to USD terms, where necessary (i.e., Total and all NOCs), see Tables B2c and B3c in Appendix B).

– Improving performance, with:
  ○ accelerating improvement rates (Field A),
  ○ steady improvement rates (Line X),
  ○ slowing improvement rates (Field B).

– No improvement in performance (Line Y).
– Detoriating performance, with:
  ○ decelerating decline in performance (Field C),
  ○ steady decline rate in performance (Line Z),
  ○ accelerating decline in performance (Field D).

The *time-series analysis* in this study classifies the trend and shape of time-series in Fig. 13a and b and then ranks them in terms of strongest (maximum mark of 6 in peer group of six companies) and weakest acceleration (minimum mark of 1 in peer group of six companies), see Tables 1a and b.

Cross-sectional analysis was subsequently applied for each time-series of the representative set of E&P companies that operate in similar markets and product ranges. This provides an additional benchmark for their relative performance in Clockspeed Accelerator 1, and ranks absolute productivity strength (maximum mark of 6 in peer group of six companies) and weakest productivity for 2007 (minimum mark of 1 in peer group of six companies), see Tables 1a and b.

The scores from the time-series analysis and cross-sectional analysis are totalled and ranked to establish the relative performance of Clockspeed Accelerators 1 in the two peer groups (see Tables 1a and b, last column).

Table 1a
Peer group ranking of Clockspeed Accelerator 1 for IOC Supermajors.

Company	Time-series analysis	Cross-sectional analysis	Total points	Rank[a]
Exxon	6	6	12	6
BP	1	2	3	1
Shell	4	3	7	4
Conoco	5	5	10	5
Chevron	3	4	7	3
Total	2	1	3	2

[a] Time-series prevails for equal total points.

Table 1b
Peer group ranking of Clockspeed Accelerator 1 for PPP NOCs.

Company	Time-series analysis	Cross-sectional analysis	Total points	Rank
Gazprom	3	1	4	2
Petrobras	2	4	6	3
ENI	5	5	10	5
Statoil	6	6	12	6
ONGC	4	3	7	4
OMV	1	2	3	1

7.2. Clockspeed Accelerator 2

Clockspeed Accelerator 2 is a lever of Improvement Rate of Risk and Uncertainty Mitigation (as outlined in Section 5), which is mainly dependent on the company's effectiveness to balance risks and rewards such that high impact negative events are avoided. In other words, a company can decide to take on higher risks but must stay at the so-called efficient frontier [25,26], so that only potentially higher profit opportunities justify taking on more risks. A concise measure of the corporate success in avoiding high impact events is the steadiness (or stability) of the return on investment (ROI), here taken over a 5-year period. The specific ROI measure used here is ROCE, the financial ratio of operating income (EBIT) and capital employed. Fig. 15a graphs the ROCE for the IOC Top 6 companies; Fig. 15b graphs similar results for the PPP NOC Top 6 companies, all translated to USD terms.

The time-series analysis classifies the stability of ROCE of Fig. 15a and b and then ranks them in terms of most stable (maximum mark of 6 in peer group of six companies) and least stable (minimum mark of 1 in peer group of six companies), see Tables 2a and b. Noteworthy, sudden steep changes in ROI in the time-series lead to lower rankings. The volatility of ROCE in the time-series analysis factors in the impact of operational risks; this proxy relationship is discussed further in the dynamic risk analysis of Appendix C.

Cross-sectional analysis was subsequently applied for each time-series of the representative set of E&P companies that operate in similar markets and product ranges. This provides an additional benchmark for their relative performance in Clockspeed Accelerator 2, and ranks absolute ROCE strenght (maximum mark of 6 in peer group of six companies) and weakest ROCE in 2007 (minimum mark of 1 in peer group of six companies), see Tables 2a and b.

The total scores from the time-series analysis and cross-sectional analysis are summed and ranked to arrive at relative ranking for Clockspeed Accelerators 2 in the two peer groups (see Tables 2a and b, last column).

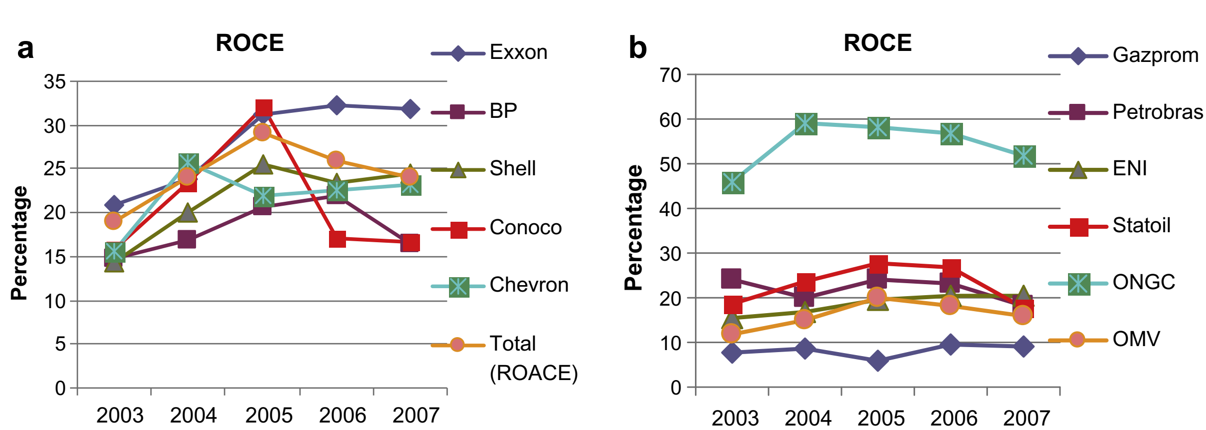

Fig. 15. (a) ROCE for the peer group of six IOC supermajors. (b) ROCE for the world's Top 6 peer group of PPP NOCs. (Data abstracted from annual company reports, see Tables B2d and B3d in Appendix B).

Table 2a
Peer group ranking of Clockspeed Accelerator 2 for IOC supermajors.

Company	Time-series analysis	Cross-sectional analysis	Total points	Rank
Exxon	6	6	12	6
BP	3	2	5	2
Shell	5	5	10	5
Conoco	1	1	2	1
Chevron	4	3	7	4
Total	2	4	6	3

Table 2b
Peer group ranking of Clockspeed Accelerator 2 for PPP NOCs.

Company	Time-series analysis	Cross-sectional analysis	Total points	Rank[a]
Gazprom	5	1	6	3
Petrobras	1	4	5	1
ENI	6	3	9	6
Statoil	2	5	7	4
ONGC	3	6	9	5
OMV	4	2	6	2

[a] Time-series prevails for equal total points.

7.3. Clockspeed Accelerator 3

Clockspeed Accelerator 3 is a lever of accrual speed of portfolio value (as outlined in Section 6), which is mainly dependent on the effectiveness of aligning the business strategy with the opportunities in the external business environment or market place. The value adding speed of a company portfolio follows from the return on investment and can be concisely expressed in terms of the ROCE (Fig. 15a and b).

The time-series analysis classifies the trend and shape of the ROCE of Fig. 14a and b and then ranks them in terms of strongest (maximum mark of 6 in peer group of six companies) and weakest acceleration of ROCE (minimum mark of 1 in peer group of six companies), see Tables 3a and b.

Cross-sectional analysis was subsequently applied for each time-series of the representative set of E&P companies that operate in similar global markets and product ranges. This provides an additional benchmark for their relative performance in Clockspeed Accelerator 3, and ranks absolute ROCE strenght (maximum mark of 6 in peer group of six companies) and weakest ROCE in 2007 (minimum mark of 1 in peer group of six companies), see Tables 3a and b.

The total scores from the time-series analysis and cross-sectional analysis are summed and ranked to arrive at relative ranking for Clockspeed Accelerators 3 in the two peer groups (see Tables 3a and b, last column).

Tables 4a and b rank the cardinal measures for scoring each of the three Clockspeed Accelerators, based on the data listed in Tables 1a–3b, for which some details are given in Appendix B. In the E&P peer group of IOC supermajors, overall clockspeed winners are: Exxon and Shell. Clockspeed laggards are: ConocoPhillips and BP. A second peer group, of the world's six foremost public private partnership NOCs, has also been subjected to time-series analysis and cross-sectional analysis to rank their relative clockspeed performance for the three accelerator dimensions defined here. In the peer group of PPP NOCs, overall clockspeed winners are: ENI, ONGC and Statoil. Clockspeed laggards are: Gazprom, Petrobras and OMV.

Table 3a
Peer group ranking of Clockspeed Accelerator 3 for IOC supermajors.

Company	Time-series analysis	Cross-sectional analysis	Total points	Rank
Exxon	6	6	12	6
BP	2	2	4	2
Shell	5	5	10	5
Conoco	1	1	2	1
Chevron	4	3	7	4
Total	3	4	7	3

Table 3b
Peer group ranking of Clockspeed Accelerator 3 for PPP NOCs.

Company	Time-series analysis	Cross-sectional analysis	Total points	Rank
Gazprom	3	1	4	1
Petrobras	1	4	5	2
ENI	6	3	9	5
Statoil	2	5	7	3
ONGC	4	6	10	6
OMV	5	2	7	4

Table 4a
Peer group ranking of Clockspeed Accelerators 1, 2 and 3 for IOC supermajors.

Company	Accelerator 1	Accelerator 2	Accelerator 3	Total points	Rank
Exxon	6	6	6	18	6
BP	1	2	2	5	1
Shell	4	5	5	14	5
Conoco	5	1	1	7	2
Chevron	3	4	4	11	4
Total	2	3	3	8	3

Table 4b
Peer group ranking of Clockspeed Accelerators 1, 2 and 3 for PPP NOCs.

Company	Accelerator 1	Accelerator 2	Accelerator 3	Total points	Rank
Gazprom	2	3	1	6	1, 2
Petrobras	3	1	2	6	1, 2
ENI	5	6	5	16	6
Statoil	6	4	3	13	4
ONGC	4	5	6	15	5
OMV	1	2	4	7	3

8. Radargraph presentation of E&P Clockspeed Accelerators

A concise graphical representation for the three clockspeed dimensions above can be practical to quickly assess the relative clockspeed performance of peer group companies; a tri-axial

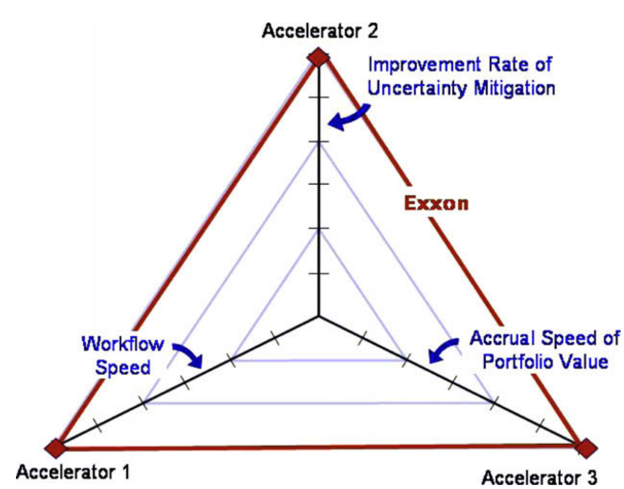

Fig. 16. Optimum E&P Clockspeed Accelerator settings. For example, this applies to Exxon, based on the peer group scaling of Table 4a.

radargraph adequately serves this purpose. Fig. 16 plots a clockspeed radargraph for the optimum case, where improvement of workflow speed, Improvement Rate of Uncertainty Mitigation (state-of-the-art Decision-Making and Risk Analysis) and accrual speed of portfolio value or full asset value in the corporate portfolio are all realized.

In contrast, suboptimum clockspeed settings occur when workflow speed is lagging, the quality of Risk and Uncertainty Mitigation is highly variable or unsuccessful in avoiding failures, and portfolio value is not fully realized, all indicated by a degree of time-averaged (under)performance of the three Clockspeed Accelerators of the company (Fig. 17).

More examples of clockspeed radargraph representations of the Clockspeed Accelerators for companies of the PPP NOCs peer group (listed in Table 4b), are given in Fig. 18a–d.

Assessing for positive or negative changes in Clockspeed Accelerators provides a powerful strategy concept and an intelligent method to steer for growth and predict the efficiency of competitive performance. As further efforts are needed to enhance E&P clockspeed acceleration, the critical drivers of E&P clockspeed are discussed in the next section.

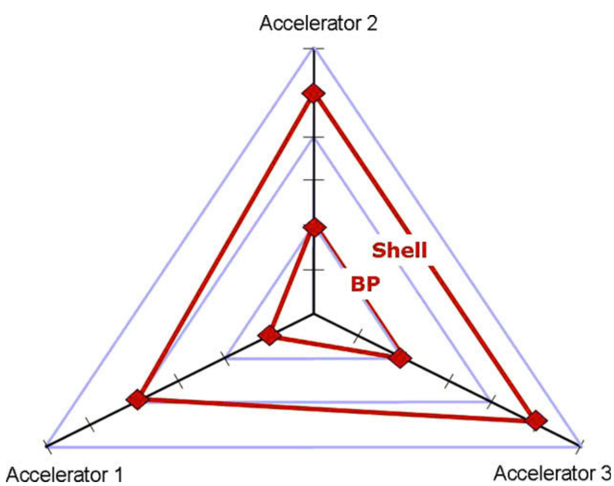

Fig. 17. Suboptimum E&P Clockspeed Accelerator settings. For example, this applies to BP and – in lesser extent – to Shell, based on the peer group scaling of Table 4a.

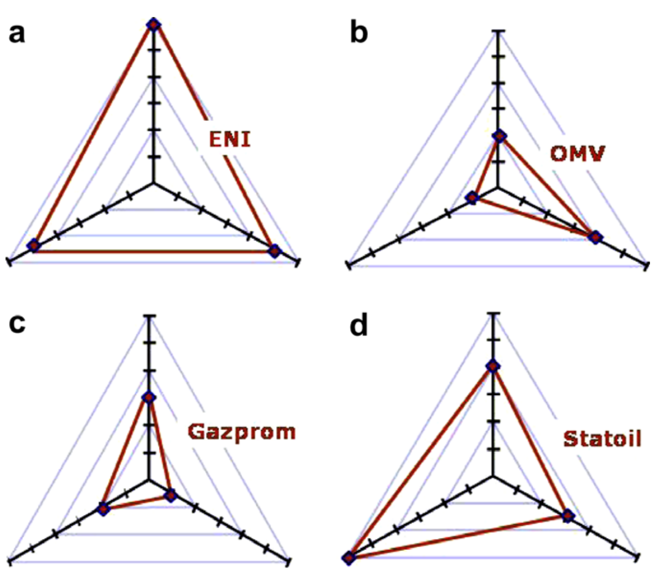

Fig. 18. E&P Clockspeed Accelerator settings for selected PPP NOCs: (a) Nearly optimum workflow speed, optimum risk mitigation, and excellent asset value realization; (b and c) suboptimum workflow speed, suboptimum risk mitigation, and suboptimum asset value realization; (d) optimum workflow speed, slightly suboptimum risk mitigation, and suboptimum asset value realization.

9. Discussion

The critical drivers of E&P clockspeed are discussed in this section for each of the three Clockspeed Accelerators. Recommendations for their optimization are formulated in Section 10. While some recent studies have analyzed the relative performance of State Oil vs. Private Oil [27,28], the present study focuses on the strategy concept of clockspeed that may be beneficial for both State Oil (NOCs) and Private Oil (IOCs). Using a limited data set of 12 companies and sourcing the primary company reports for performance measures, allows the formulation of specific recommendations for practical application. Before discussing the critical drivers of E&P clockspeed, some highlights of previous research on the performance of Private Oil vs. State Oil are summarized here.

Late 20th century, Al-Obaidan and Scully [29] concluded that state-owned enterprises are only 0.61–0.65 times as technically efficient as private firms, based upon an econometric study of efficiency differences between 44 international private and state-owned petroleum companies (observed between 1976 and 1982). Eller et al. [30], taking revenues as output and number of employees, oil reserves and gas reserves as inputs, concluded that the average technical efficiency score for NOCs is 0.27, compared to 0.73 for the five biggest private companies and the industry segment's sample average is 0.40 (on a sample of 80 firms for the period 2002–2004). Another historic econometric study was recently completed by Wolf and Pollitt [28], who concluded that (partial or complete) privatization of oil companies is associated with comprehensive and sustained improvements in performance and efficiency. Privatized companies saw total output grow by 40%, capital expenditure by 47%, and employment intensity drop by 35% over a 7-year period around the initial privatization offering (using a dataset of 60 public share offerings by 28 NOCs).

Econometric analysis by Wolf [27] of the performance and efficiency of State Oil (23 NOCs, 100% state-owned) vs. Private Oil (21 IOCs, fully private firms) over a 20-year period (1987–2006) showed that the NOCs studied employ up to 71% more personnel for a comparable asset base, and generate up to 18% less output from these assets than its private counterpart. The difference in performance between OPEC NOCs and non-OPEC NOCs is particularly striking: across the 20-year sample non-OPEC firms on average have a 2.3 times higher labour intensity ratio (employees/assets) than OPEC firms, and their output per employee is 66% lower than that of the OPEC benchmark. Table 5 highlights the major differences between IOCs and NOCs. Particularly interesting is the fact that the fully state-owned Top 5 NOCs generate more physical output per employee than the Top 5 IOCs (68,800 bbl/employee vs.

Table 5
Relative workflow efficiency of IOCs vs. NOCs.

Companies	Annualized Output per employee (kilo-bbl)	Revenue per employee (million USD)	Net income per employee (USD)
Top 5 IOCs	51.5	1.36	80,300
Top 5 NOCs	68.8	0.77	67,900
All Private Oils	37.9	0.80	64,400
All State Oils	31.7	0.44	40,000

All numbers 20-year averages (1987–2006), data analyzed by Wolf [27].
Top 5 IOCs: Exxon, Shell, BP, Chevron & ConocoPhillips.
Top 5 NOCs: Saudi Aramco, NIOC, KPC, Sonatrach & PDVSA.

51,500 bbl/employee). Nonetheless, the Top 5 NOCs do not generate more revenue per employee than the Top 5 IOCs (770,000 USD/employee vs. 1,360,000 USD/employee; 20 year averages, see Table 5).

The physical output performance of the Top 5 NOCs vs. Top 5 IOCs (see Table 5) is mostly assumed an effect of 'easy oil' vs. 'complex oil' [27]. The hydrocarbon reserves of the Top 5 State Oils are trapped in huge geological reservoirs from which can be produced at low cost: with no or little flow stimulation, using facilities that remain operational for decades. In other words, the reservoirs of the Top 5 NOCs can be produced with favorable capital and labour requirements. In spite of their high physical output, revenue and net income of the Top 5 NOCs are depressed by subsidized sale of oil products in domestic markets and heavy reliance on external service companies and consultancies (which pushes OPEX up and earnings down). Additionally, the NOCs majors suffer huge working capital tie-ups (receivables, capital advances to the State), and OPEX and CAPEX are often burdened with some responsibility for public health services and other community services, including infrastructure development.

The two peer groups of Top 6 NOCs and Top 6 IOCs compared in this study operate in increasingly comparable global markets. The labour efficiency plots of Fig. 13a and b confirm that IOCs tend to generate more net income per employee as compared to the PPP NOCs. Nonetheless, Statoil's net income per employee for 2006 and 2007 (Fig. 13b, Table B3c) is higher than that of BP and Total (Fig. 13a, Table B2c). This confirms yet another older insight, i.e., there is not necessarily an inherent superior performance of private firms vs. public firms, provided they operate under similar competitive pressures and in liberalized markets [31,32].

The critical drivers of E&P clockspeed can be concluded from the empirical analysis in Sections 7 and 8 of this study (using historic data over the period 2003–2007) for each of the three Clockspeed Accelerators.

9.1. Accelerator 1

Drivers include internal efficiency, effectiveness of internal cooperation, the alignment of business processes, technology integration, and organizational learning.

What is Exxon doing better than its peer group of IOC supermajors to achieve such an efficient workflow speed resulting in extraordinary productivity growth and exceptionally high earnings per employee (500,000 USD/employee in 2007)? Likewise, what is Statoil doing better than its peer group of PPP NOCs to achieve such a high growth in earnings per employee (280,000 USD/employee in 2007)?

The E&P industry is known to be *capital intensive*: in 2007 the average annual revenue per employee reached about 5 million USD for IOCs. Exxon excels at due diligence and a military style of central decision-making, central planning and global execution. Evidently, its internal cooperation is effective, business processes run efficient, and its technology is well-integrated. Exxon is known to be careful with the application of new technology; innovative technologies must first be proven before adopted by Exxon. But Exxon's exceptionally high earnings per employee (Shell is runner up in the IOC peer group with a mere 300,000 USD net profit/employee for 2007) also includes an additional income effect, as follows. Exxon excels at engaging in joint ventures that it helps jump start, based on its global brand strength, but does not operate (hence adding profit but ensuring low OPEX). For example, Exxon is a 50% stakeholder in the Dutch NAM (effectively 30% via Maatschap Groningen) for half a century, but currently has only seven employees (mostly accountants dedicated to cashflow control and CAPEX decision-making) to rake in an annual net income of 2.5 billion USD from the NAM joint venture (2007); contributing a handsome 6% to Exxon's 2007 corporate net income. Exxon repeatedly applies its joint venture model of low OPEX/high royalty, for example, in a 2004 agreement with Apache that gives Exxon a 37% royalty in return for Apache's right to drill and produce on 1.2 million acres of hard-to-drill prospects in central Canada. In other words, in addition to due diligence in workflow speed, Exxon's secret weapon is this: negotiating favorable terms for long-term joint ventures that keep the corporate OPEX low and royalties high.

In contrast with Exxon, Statoil has an open company culture and is known to spend heavily on life-long learning and professional training of its employees. Internal efficiency optimization – effectiveness of internal cooperation, efficiency of business processes and technology integration – is a major focus area for Statoil management. Organizational learning is high on the corporate agenda and innovative technologies are not shunned if these can help to complete field development projects faster, with better production efficiency and higher recovery rates. Statoil's net income is under some pressure by a steep rise in its production cost in 2007 – the first year in company's history where production costs of domestic barrels were higher than its international production costs. Although Statoil's average production cost rose to just over 8 USD/bbl in 2007, the company was still outperforming, in its PPP NOC peer group, the runner up Clockspeed Accelerator 1 top performer ENI, which produced at 12.5 USD/bbl in 2007. While potentially depressing net earnings/employee, the oil price rose fast enough between 2006 and 2007 (see Figs. B3 and B4) to outpace Statoil's doubled production costs over that period (from 4.16 USD/bbl for 2006 to 8.15 USD/bbl for 2007; Fig. 19). The rise in oil price improved earnings, while employee OPEX for 2006 and 2007 remained much the same, thus boosting earnings per employee in 2007 (Fig. 13b).

The productivity of Petrobras has slightly dropped since peaking in 2006 (Fig. 13b). This is due to 6600 more people on OPEX for 2007 as compared to 2006 (Fig. B2b, Table B3b), which did not translate to higher earnings – net income remained flat for the same period. This may imply that Petrobras is having troubles in leadership succession when young and new hires are phased-in to replace its soon-to-retire experienced workforce.

OMV of Austria, with the slowest setting for Clockspeed Accelerator 1, is recovering from its 2004 acquisition of Petrom of Romania, which added some 50,000 employees to its workforce. Clearly, OMV needs to invest in people training and replacement, modern technology, and improved business processes to speed up the OMV/Petrom workflow. The same applies to the second worst performer for Clockspeed Accelerator 1, i.e., Gazprom. In spite of low wages, Gazprom's humongous workforce of 220,000 people keeps

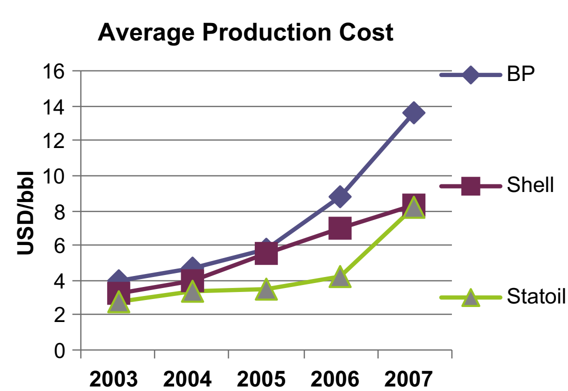

Fig. 19. Average production costs are accelerating steeply for all E&P companies, but some are affected more than others.

OPEX high (Fig. B2b, Table B3b) which translates to an underperformance in labour efficiency (60,000 USD/employee in 2007, see Fig. 13b). Considering the lifting effect of the exceptionally high oil prices for 2007 (Figs. B3 and B4) on productivity, Gazprom's recent performance for Clockspeed Accelerator 1 certainly leaves plenty of room for improvement.

9.2. Accelerator 2

Drivers include balancing of risk and opportunity, at the efficient frontier.

The Top 6 PPP NOCs all show relatively stable risk mitigation track records; these companies are risk-averse, which can be seen from relatively steady ROCE time-series (Fig. 15b). Historically, PPP NOCs tend to have easier access to acreage, which explains why these companies benefit from low risk/high opportunity trade-offs. However, the imminent depletion of domestic oil fields has urged several PPP NOCs to explore and develop new fields abroad. For example, Statoil now finds cheaper production acreage outside Norway's national borders (Statoil's 2007 annual report). Whereas PPP NOCs traditionally tend to avoid high impact events on ROCE, Statoil is now forced to take on higher risks. For example, Statoil reduced debt in 2007 (Fig. 20b), due to its merger with the lower-geared Hydro to form StatoilHydro, but that also meant that the proportion of borrowed capital or the corporate debt was reduced as compared to its equity financing part of the total capital employed (Fig. 20b). The cost of the merger explains the steep drop in ROCE from 27% to 19% from 2006 to 2007 (Fig. 15b). Such steep ROCE drops commonly occur when there is a steep climb in working capital, CAPEX and fixed assets, while earnings lag behind [33], for relationship between ROCE and gearing ratio and RONA). This typically occurs when mergers or new projects demand capital injection before ROI kicks in positively.

Whereas PPP NOCs only engage in higher risk ventures when forced abroad by dwindling national opportunities, the IOC supermajors traditionally tend to take more risk. This results in exceptionally high ROCE for some, like Exxon, but sharp drops in ROCE for others. For example, ConocoPhillips' 2005 peak ROCE of over 32% dropped to 17% and 16.6% for 2006 and 2007 (Fig. 20a). Again, such drops in ROCE commonly occur when there is a steep climb in working capital, CAPEX and fixed assets, while earnings (ROI and ROCE) lag behind [33]. In the case of ConocoPhillips, it 2006 acquisition of Burlington Resources depresses its ROCE.

Steep drops in ROCE can be minimized when the decision-making process is optimized by risk mitigation through risk analysis so that the application of (new and proven) technology and new project options and business ventures are supported by the right decisions at the right time. Such an approach reduces the frequency of production downtime, project delays and failures. While IOCs traditionally are accustomed to assess the higher risk opportunities, the late lifecycle stage of the Oil & Gas industry (see Section 1 and Fig. 1) drives IOCs to take on projects that are more complex and riskier than ever before. The need for a rigorous risk analysis and decision-making process therefore has only increased in recent years.

9.3. Accelerator 3

Drivers include global brand strength, project phasing, project option generation, CAPEX control, and control of production cost.

Winners for Clockspeed Accelerator 3 performance in their respective peer groups are Exxon and ONGC. How do these companies realize their sustained high ROCE's?

Exxon's high ROCE's (Fig. 15a) can be explained by rigorous CAPEX and OPEX control, and joint ventures that Exxon helps jump start, based on its global brand strength, but does not operate (low OPEX). Moreover, Exxon's strategy seems exceptionally well-aligned with the competitive external environment over longer periods. That translates into Exxon's project portfolio ability to line-up and phase project investments such that the profits stack up positively. In other words, the drops in ROCE that commonly occur when companies incur sudden, steep climbs in working capital, CAPEX and fixed assets, when earnings (ROI and ROCE) lag behind, are avoided by Exxon leadership.

ONGC manages its unrivalled ROCE of over 50% (Fig. 15b) by benefitting from low cost labour and due diligence in project phasing. Also, ONGC is a zero-debt company (Fig. 20b), which in the Indian subcontinent is seen as an attractive investment opportunity for equity financers.

BP's steep ROCE drop from 23% in 2006 to 16.5% in 2007 (Fig. 15a) can be ascribed to spiralling production costs (Fig. 19), and dropping net income (Fig. B1a) due to delays in project completions and disasters in project portfolio (country risk – TNK PB, plant risk – Galveston).

ConocoPhillips is an interesting case where a near-optimum Clockspeed Accelerator 1 setting (high workflow speed and thus high labour efficiency, see Fig. 13a) combines with poor peer group performance for Clockspeed Accelerators 2 and 3 (Fig. 21).

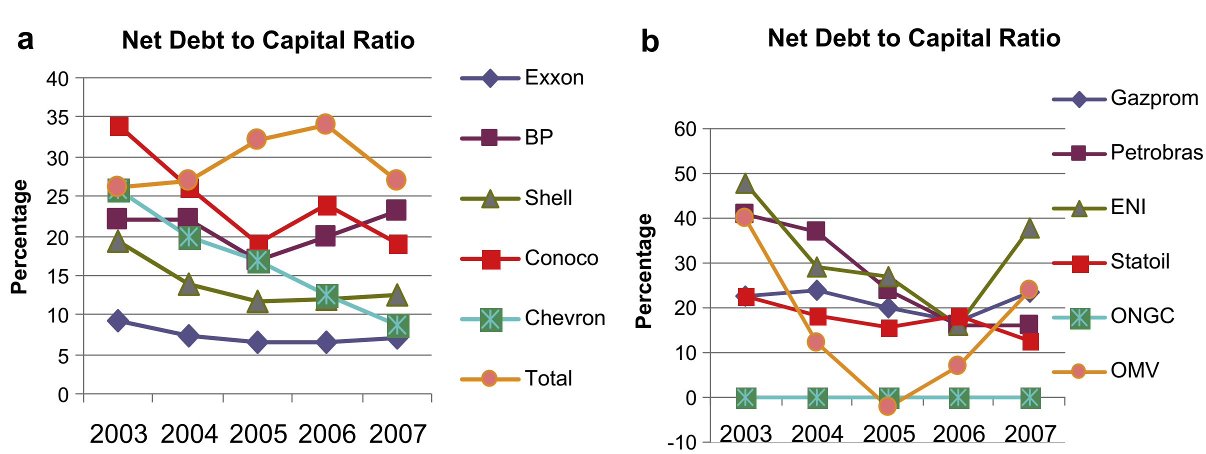

Fig. 20. (a) Gearing (UK term) or Leverage (US term), which is the ratio of total (interest-bearing) debt to total capital (i.e., debt plus shareholder equity) for the peer group of six IOC supermajors. (b) Gearing for the world's Top 6 peer group of PPP NOCs (data abstracted from annual company reports; see Tables B2e and B3e).

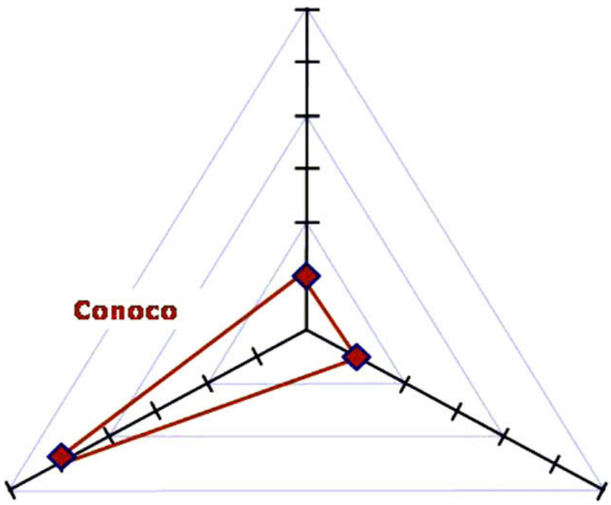

Fig. 21. Clockspeed Accelerator settings for ConocoPhillips, based on the peer group scaling of Table 4a.

10. Recommendations

The examples of the time-series analysis and cross-sectional analysis for the two peer groups of Oil & Gas companies examined in this study, have provided the following practical insights:

Clockspeed Accelerator 1, a lever of workflow speed or labour efficiency (productivity), can be optimized by:

- ○ Ensuring effective internal cooperation.
- ○ Enhancing efficiency and alignment of internal business processes.
- ○ Maximizing integration of people, business processes and technology.
- ○ Validating of new technology before application.
- ○ Negotiating favorable terms for long-term joint ventures that keep the corporate OPEX low and royalties high.
- ○ Completing field development projects faster, with better production efficiency and higher recovery rates.
- ○ Avoiding steep rises in production costs.
- ○ Investing in people's professional development, continued education and leadership succession.

Clockspeed Accelerator 2, a lever for Improvement Rate of Risk and Uncertainty Mitigation, can be optimized by:

- ○ Balancing risk and opportunity to avoid steep drops in ROCE that is a KPI for poor risk management if unsteady over the medium-term. IOCs with dwindling global reserves are driven to deeper waters, colder seas, and riskier political regions for access to scarce new acreage. Likewise, NOCs with dwindling national reserves are now also moving abroad for new opportunities. Both type of companies need to balance risks and opportunities using sophisticated optimization models to manage all the new and old risks.
- ○ Avoiding steep climbs in working capital, CAPEX and fixed assets, when earnings lag behind – speedy ROI needs to be assured in all new project investments, mergers and acquisitions.
- ○ The decision-making process for new investments needs to go further than NPV calculations. Decisions must be based on sound uncertainty modeling and risk analysis to ensure that decisions about new technology and business opportunities are supported by the right resources at the right time.
- ○ Choosing an appropriate gearing or leverage of debt and equity financing to provide a buffer for new activities.

Clockspeed Accelerator 3, a lever for Speed of Corporate Value Adding Capacity, can be optimized by:

- ○ Aligning the corporate strategy with the external business environment.
- ○ Making sure that the project options are varied and numerous so that the portfolio can be fed and fitted with the right projects at the right time.
- ○ Monitoring project performance and feed this back into the corporate project portfolio for continued optimization: the leadership must be prepared to kill a project if suboptimum. Simultaneously, continually generate and evaluate new project options, in a timely fashion.
- ○ Hiring well-trained professionals from low-labour cost countries – if available – as this can translate into higher ROI.
- ○ Keeping production costs down and avoiding delays in project completions.
- ○ Optimizing HSE performance under all circumstances, as this is required for ethical reasons, corporate reputation and to avert disasters that might bite hard into the corporate earnings and brand name.

In all energy companies with resources to acquire the best technology and hire talented people, the principal focus must be on pushing forward from 'best practice' to structural and engrained improvement of the workflow speed, Rate of Risk and Uncertainty Mitigation and Pace of Portfolio Valorization. The suggested efficiency improvements for the E&P clockspeed outlined here can help to further monitor and optimize the performance of individual companies.

11. Conclusions

The present study benchmarks Clockspeed Accelerators for the Oil & Gas industry and effectively integrates operational performance indicators with financial indicators. Management methods in Oil & Gas companies have incrementally matured over the past century in the quest to meet both market demand and reserve replacement expectations. Further expansion of exploration and development of hydrocarbon resources in the 21st century needs young talent and the stimulation of emergent new leadership [34], to help fill the energy supply gap. The supply gap can be bridged only if companies continue to succeed in closing operational hurdles due to limitations of current technology, associated professional skills, processes and workflow efficiency. The industry must persevere to learn ever faster to operate beyond 'best practice' by speeding up its innovation cycle in all four areas (people management, technology development, process & lifecycle innovation and workflow efficiency). An additional challenge is the actual realization of the optimized best practice and the implementation of new concepts (by continual and rapid Organizational Learning), including Clockspeed Acceleration.

E&P companies are commonly very goal-oriented, not people oriented. A proactive policy is needed that gives sanctuary to new leaders and brilliant ideas. It is worthwhile to encourage gamechangers in the leadership pipeline model – the economic benefit of investment in people can be quantified [34]. In order to implement innovations in technology, process and workflow faster, the management skills that are particularly important for petroleum projects include: leading effective change, leadership and human behavioral skills, multicultural team management, managing project risks, and knowledge management in

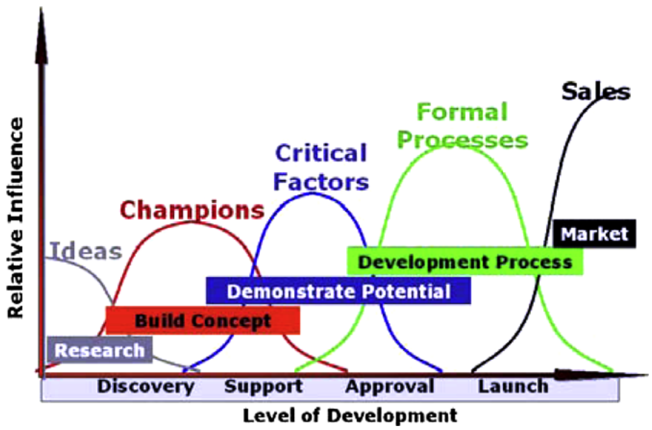

Fig. 22. Best practice innovation: the acceptation of best practice improvements needs time. The implementation commonly follows a workflow architecture and protocol itself, with Go/No-Go decision moments as suggested here.

learning organizations. Individual persons that contribute to improvement of the 'best practice' workflow also must pay attention to structural adoption for company wide implementation (Fig. 22).

Effective leadership and vision are required to capitalize on beyond 'best practice' innovations across all biases. To address this leadership challenge, Delft University of Technology has developed a Master of Petroleum Business Engineering (MPBE) program together with partner organizations (TNO, IFP, OGCI/PetroSkills, Energy Delta Institute) and launched this programme in 2005 after close consultations with industry partners. The philosophy of the MPBE program includes the development of future E&P leaders and asset managers with a new mindset: make decisions that fully account for workflow optimization, stochastic modeling of uncertainties and realization of asset and portfolio value [35–37]. At the corporate level, it is the effective interaction of professionals, talent management, career-growth opportunities and employee retention rate that contributes to preservation and expansion of the company's best practice that leads to higher performance. Capable staff should focus on high-potential issues and complex problems and continually needs to innovate or refresh current 'best practice' with insights from new science and technology. The Thesis projects in the MPBE tackle such issues by solving, among others, field development problems. The MPBE program thus provides a laboratory facility that not only enhances the competencies of individual professionals, but also brings about a tangible research outcome for the participating companies, as outlined elsewhere [35,36].

Disclaimer

This study contains a conceptual analysis – in particular in Sections 7 and 9 – regarding return on capital employed, financial gearing, labour efficiency and production costs, based on data abstracted from company reports. By its nature, the analysis of empirical data involves a degree of uncertainty connected to the assumptions made. For example, the equity performance of the companies in terms of shareholder return has not been taken into account in this study. The author and publisher take no responsibility for any liabilities claimed by companies listed in this study.

Appendix A. Best practice workflow in Oil & Gas business

In the upstream Oil & Gas business, the workflow at the field development level has been optimized over the years to facilitate the realization of the full project or field development value by effective execution of each phase of the project lifecycle. Although the workflow has been optimized, the overall scope of the workflow architecture often remains hidden in compartmentalized workflow sections. The E&P workflow architecture is organized around six attribute groups, as follows (Fig. A1):

(1) Decision gate aims (e.g., licence application, licence award, etc.),
(2) Strategy options (e.g., seek opportunities, evaluate reserves, etc.),
(3) Workflow sections (e.g., exploration, appraisal, etc.),
(4) Decision gate stops (DG-A, DG-B, etc.),
(5) Workflow process focus (e.g., value identification, and value realization),
(6) Motto (e.g., choosing project option and executing project option).

Each of the attribute groups distinguished in Fig. A1 serves a key purpose in the workflow process. Their purpose can be summarized as follows:

(1) *Decision gate aims*: These are the goals in terms of specific physical deliverables on which company resources hinge and for which major decisions need to be made (e.g., licence application, licence award, etc.). The purpose of this attribute in the workflow architecture is to make better and focused decisions.
(2) *Strategy Options*: These are the actions initiated to generate strategy options – aligned with corporate strategy – and to rejuvenate the corporate portfolio with projects that balance risk and opportunity at the efficient frontier (e.g., seek opportunities, evaluate reserves, etc.). The purpose of this attribute is to generate real strategy options.
(3) *Workflow sections*: These are the compartmentalized workflow phases (e.g., exploration, appraisal, etc.) separated by workflow boundaries that coincide with major decision gates. The purpose of this attribute is to prepare dedicated decision support packages based upon data, modeling and recommendations to meet the decision gate aim.
(4) *Decision gate stops*: These are the pre-determined deadlines for decision gate delivery of the decision gate support package. Most companies use specific decision gate labels for these E&P gate stops at decision gates (e.g., DG-A, DG-B, etc.). The purpose of this attribute is to decide the setting of the workflow switches for further workflow motion.
(5) *Workflow process focus*: These summarize the overall workflow aims for a group of workflow sections (e.g., value identification, and value realization). The purpose of this attribute is to keep focus of the overall workflow process.
(6) *Motto*: These are the brief statements that people keep repeating on the work floor (e.g., "Choose the right project" for value identification, and "Do the project right" for value realization). The purpose of this attribute is to inspire the teams in the workflow sections to do things right or even better.

The concept of a *Decision-making Support Package* (DSP), designed to aid decision-makers. The DSP is prepared to offer senior management a choice between alternatives based on estimates of the values of those alternatives. The DSP includes information

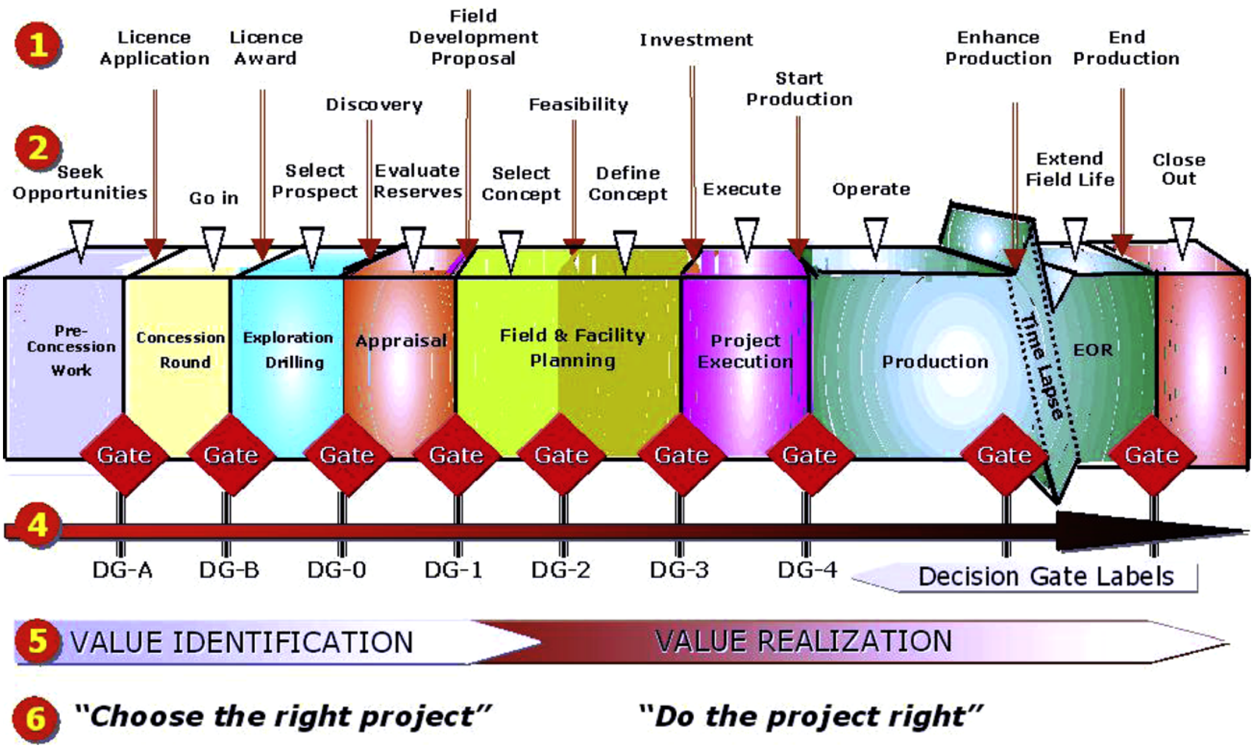

Fig. A1. E&P Workflow architecture for development of upstream Oil & Gas projects. The workflow includes six attribute groups: (1) decision gate aims, (2) strategy options, (3) workflow sections, (4) decision gate stops, (5) workflow process focus, and (6) motto. For further explanation see text (compiled from a variety of company sources).

gathering, the generation of alternatives, and quantification of comparisons of alternatives. The project is reviewed in periodic Gate-Stage or Value Assurance Reviews, using a common DSP structure that enables gatekeepers and decision-makers to ease the communication on the project status. The DSP structure is commonly comprised of five steps, as follows (Fig. A2):

Step 1: Framing the problem – Introduces the asset(s) and area involved. Describes the problem and business challenges in terms of technology and economics. If applicable, geopolitical issues are outlined as well. This DSDP section defines a well-framed problem, and states the research goals.
Step 2: Method of solution – Here, the DSP explains the resources (people, tools and processes) that will be used, and the method(s) followed, to come to a solution. This includes literature review, selection of software tool, interviews, risk inventory, data gathering and so on.
Step 3: Research process – In this Step, the actual research activities are described in terms of workflow and results. Observations and intermediate results of multiple runs are discussed. Special attention should be given to the decision and risk analysis procedure.
Step 4: Risks, results and proposed solution – Based on the research results, the conclusions and recommendations are formulated in relationship with the preset goals. The conclusions need to be based on the decision and risk quantified in the research process.
Step 5: Recommendations and implementation plan – Conclusions and recommendations are transformed into an implementation plan for the company. For this plan, the following basic elements need be used: smart goals, balanced scorecard, time schedule, risk register, resources and so on.

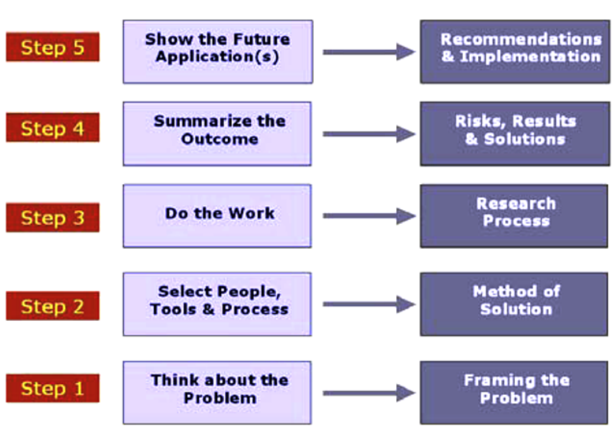

Fig. A2. Decision-making Support Package: five systematic steps are recommended when initiating a problem-solving business action. The steps ideally correspond to chapters in the DSP. Identification of the problem in Step 1 should be fine-tuned with the team members selected in Step 2.

Gate stops are the specific decision gates in project development where decision-makers assess the Decision Support Packages (DSPs) prepared by the expert teams. The decision-makers weigh the gate aims against risks and opportunities, keeping sight of the Corporate Strategy when assessing the project options. They may decide (Fig. A3): to proceed to the next phase, to rework in the preceding phase, to stall the project, to change the project scope, or to kill the project. A Gatekeeper checks the decision support package for completeness, audits the decision-making process for integrity, and helps to minimize any undue delays at the decision gates.

Appendix B. Data aggregation for scaling Clockspeed Accelerator benchmark axes

Benchmark data for the energy industry, crucial for our world economy, are continually monitored and published by government

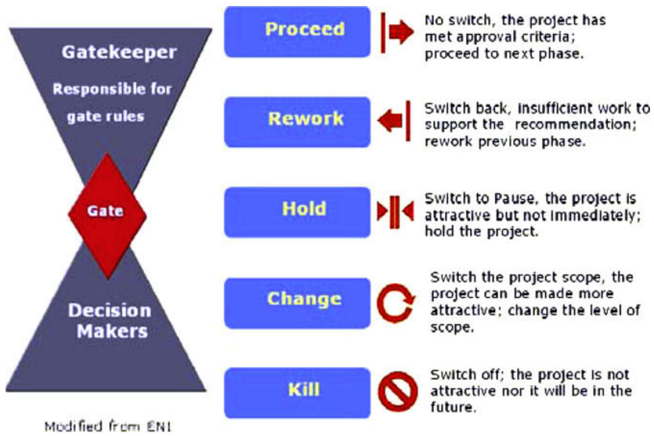

Fig. A3. Workflow switches at decision gate stops. These are monitored by a Gatekeeper and Decision-Makers decide whether to proceed, rework, hold, change, or kill the project (based on ENI Gatekeeper Policy).

agencies (the European IEA, and USA's EIA, etc.), commercial publishers (Energy Intelligence, Platts, Plunkett Research, etc.), and associations (e.g., International Association of Oil & Gas Producers *Safety Performance Indicators*).

The 12 oil companies used in this study are selected from the companies ranked by the Energy Intelligence in its annual '*Top 100 Ranking of the World's Oil Companies*'. Energy Intelligence Group is a publishing and information services company which includes Petroleum Intelligence Weekly (PIW). The annual benchmark of PIW is recognized throughout the industry as the leading source of comparative assessments on the performance of all the world's leading oil companies. The 100 companies examined in the 2008 edition of '*The Energy Intelligence Top 100*' account for 87% of global oil production, 88% of global oil reserves, 73% of global refining capacity and 87% of global refined product sales. For the first time in years, IOCs outnumber NOCs in the top ten, helped by the ascent of ConocoPhillips and its acquisition of Burlington Resources, which moved it ahead of Chevron and Total.

The ranking of PIW is based on operational data from over 130 firms. Firms are compared in six different operational areas (liquid production, gas production, reserves of liquids, and reserves of gas, refining capacity and product sales), with companies assigned a separate rank within each category. The six individual ranks are then added together to determine the cumulative, overall position, giving each of the six criteria an equal weighting. For state-owned oil companies that do not release regular or complete annual reports in a timely fashion, estimates are used mainly. Estimates are also used when complete corporate data are not available. The 2008 listing uses data that cover 2006, and the top 50 list is given in Table B1.

From the PIW ranking list in Table B1, a selection was made for a comparative clockspeed study of the following companies:

– The IOC Top 6 (supermajors, highlighted in yellow in Table B1), which are all stocklisted and KPIs for operational performance, HSE record and financial performance are publicly available. The IOC Top 6 comprises: Exxon, BP, Shell, ConocoPhillips, Chevron, and Total.
– The Public Private Partnership NOC Top 6 (PPP NOCs are those NOCs that are only partly privatized, highlighted in green in Table B1), and henceforth stocklisted, with performance data published in the public domain. The PPP NOC Top 6 comprises: GazProm (50.0023% State), Petrobras (32.2% State), ENI (30% State), Statoil (70.9% State), ONGC (74.14%), and OMV (31.5% State). Sinopec is excluded here for lack of accessible data; PDO for its inclusion in the Shell stake; Rosneft for its similarity to Gazprom's reporting practice, which would introduce too much bias into the PPP NOC peer group.

Table B1
Top 50 ranking of World's Oil Companies.

Rank 2006	Rank 2005	PIW Index	Company	Country	State share (%)
1	1	30	Saudi Aramco	Saudi Arabia	100
2	3	33	NIOC	Iran	100
3	2	37	Exxon Mobil	US	0
4	5	52	BP	UK	0
5	4	55	PDV	Venezuela	100
6	6	60	Royal Dutch Shell	UK/ Netherlands	0
7	7	61	CNPC	China	100
8	11	78	ConocoPhillips	US	0
9	8	84	Chevron	US	0
10	8	85	Total	France	0
11	10	87	Pemex	Mexico	100
12	15	96	Gazprom	Russia	50.0023
12	12	96	Sonatrach	Algeria	100
14	13	103	KPC	Kuwait	100
15	14	106	Petrobras	Brazil	32.2
16	17	123	Adnoc	UAE	100
17	16	126	Lukoil	Russia	0
18	19	127	Petronas	Malaysia	100
19	18	144	Eni	Italy	30
19	20	144	NNPC	Nigeria	100
21	24	157	QP	Qatar	100
22	23	158	INOC	Iraq	100
23	22	161	Libya NOC	Libya	100
24	26	168	Rosneft	Russia	75.16
25	21	169	Repsol YPF	Spain	0
26	24	173	EGPC	Egypt	100
27	26	186	Surgutneftegas	Russia	0
28	29	193	Statoil	Norway	70.9
29	28	194	Sinopec	China	71.23
30	33	216	Pertamina	Indonesia	100
31	30	219	ONGC	India	74.14
32	35	237	PDO	Oman	60
33	32	243	Yukos	Russia	0
34	31	255	Marathon	US	0
35	34	268	SPC	Syria	100
36	36	275	Socar	Azerbaijan	100
37	44	285	Anadarko	US	0
37	39	285	EnCana	Canada	0
39	40	289	Ecopetrol	Colombia	100
40	38	290	TNK-BP	Russia	0
41	43	296	Devon	US	0
42	45	297	Apache	US	0
43	36	300	OMV	Austria	31.5
44	50	304	CNR	Canada	0
44	46	304	Occidental	US	0
46	47	307	Norsk Hydro	Norway	45.9
47	49	309	BG	UK	0
48	42	310	Hess	US	0
49	51	315	Novatek	Russia	0
50	–	318	Inpex	Japan	29.35

Yellow highlights: Top 6 IOCs; green highlights: Top 6 PPP NOCs; and orange highlights: Top 6 NOCs. (For interpretation of the references to color in this Table legend, the reader is referred to the web version of this article.)

It must be emphasized that PIW's ranking does not take into account financial performance. In general, benchmark data typically focus on either operational performance indicators (such as production volumes, reserve replacement ratios, and exploration drilling success), or financial KPIs (ROCE, total shareholder return, oil price and profitability, net income per barrel produced). Alternatively, HSE Performance is monitored (H – days of sick-leave; S – Personal Safety, i.e., number of deaths and injuries; E – Process safety, i.e., oil spills, gas flaring, carbondioxide emissions), often in conjunction with sustainability targets and community development. The clockspeed acceleration concept outlined in this study integrates operational performance indicators with financial indicators and acknowledges the importance of HSE for clockspeed optimization.

For the 12 companies examined in the present study, 60 annual reports were studied to abstract and compare trends in relative clockspeed performance over a 5-year period (2003–2007). Tables B2a–e and B3a–e provide the numerical data abstracted from the company reports and used for the time-series analysis and cross-sectional analysis of the Clockspeed Accelerator indices for the two peer groups.

Clockspeed Accelerator 1 is a lever of workflow speed, which is mainly dependend on the effectiveness of internal cooperation, efficiency of business processes and technology. A concise measure of the corporate performance in workflow speed is the productivity, expressed here in terms of corporate net earnings per employee. Fig. B1a graphs the net income for the peer group of the Top 6 IOC companies; Fig. B1b graphs the net income for the peer group of Top 6 PPP NOC companies. The number of employees for both sets of E&P companies is graphed in Fig. B2a and b. These data are used to graph the ratio of Net Income and Number of Employees per company as given in Fig. 13a and b of the main text.

For an assessment of the commodity risk, referred to in Section 9, the historic volatility of the oil price has been graphed for the past 6 years in Fig. B3. The annual average of the oil price for the past 36 years has been graphed in Fig. B4.

Appendix C. Dynamic risk analysis

The volatility of ROCE, examined in the time-series analysis for the two peer groups of Oil & Gas companies studied (Fig. 15a and b), factors in the impact of operational risks. Nonetheless, the correlation between operational risks and ROCE volatility as a proxy for risk mitigation remains an area that requires further work [38]. Further insight into the intricate relationship between risk and performance (both operational and financial) is merited and follows from a dynamic analysis as outlined below.

The boundary condition for investors in the Oil & Gas sector is given by the Capital Asset Pricing Model (CAPM), which mandates that capital is better held at the bank with risk-free ROI, unless riskier business investments become more profitable by yielding higher ROIs from the business projects. Responsible investors are risk-averse and therefore demand a business utility function which generates higher returns when higher risks are assumed (i.e., larger Sharpe Ratios). The Sharpe Ratio is a dynamic measure of the excess return (Risk Premium on investment) against its tendency to fluctuate over time per unit risk assumed (the average return of a portfolio at risk divided by the standard deviation [39]). Mostly used for financial portfolios, Sharpe Ratios for project performance in an oil company's portfolio must indicate that any higher risks assumed stay balanced (time-averaged) with the expected returns for the optimized portfolio (i.e., at the efficient frontier [25]). If the company's project portfolio is not optimized, maintaining investment in the company gives a suboptimum Risk Premium. Rigorous application of the CAPM then may lead knowledgeable investors to decide for withdrawal of their investments from the company in order to reduce their risk exposure.

When capital works for an Oil & Gas company, the CAPM mandates that a company's ROI (e.g., ROCE determined by the ratio of profit over investment) must be higher than the ROI earned by any other company, and in any case must outperform the bank's

Table B2
Key indicators for peer group of Top 6 IOCs.

	2003	2004	2005	2006	2007
(a) Net income or earnings (billions USD)					
Exxon	21.5	25.3	36.1	39.5	40.6
BP	12.6	17.3	22.6	22.3	21.2
Shell	12.3	18.5	25.3	25.4	31.3
Conoco	4.7	8.1	13.5	15.65	11.9
Chevron	7.2	13.3	14.1	17.1	18.7
Total	9.1	15.2	15.0	16.0	19.9
(b) Number of employees (thousands)					
Exxon	88.3	85.9	83.7	82.1	80.8
BP	103.7	102.9	96.2	97.0	97.6
Shell	119.0	113.0	109.0	108.0	104.0
Conoco	39.0	35.8	35.6	38.4	32.6
Chevron	50.6	47.3	53.4	55.9	59.2
Total	110.8	111.4	112.9	95.1	96.4
(c) Ratio earnings/employees (US dollars/employee)					
Exxon	243,601	294,878	431,661	481,121	502,599
BP	121,678	167,755	235,260	229,753	216,895
Shell	103,546	164,071	232,211	235,574	301,260
Conoco	121,410	227,067	380,028	404,948	364,755
Chevron	142,885	281,776	264,026	306,583	315,676
Total	81,768	136,510	132,616	168,435	206,816
(d) ROCE (%)					
Exxon	20.9	23.8	31.3	32.2	31.8
BP	14.7	16.9	20.7	21.9	16.5
Shell	14.4	20.1	25.6	23.4	24.4
Conoco	15.8	23.3	32.1	17.0	16.6
Chevron	15.7	25.8	21.9	22.6	23.1
Total (ROACE)	19.0	24.0	29.0	26.0	24.0
(e) Net debt to capital ratio (%)					
Exxon	9.3	7.3	6.5	6.6	7.1
BP	22.0	22.0	17.0	20.0	23.0
Shell	19.4	13.8	11.7	12.1	12.6
Conoco	34.0	26.0	19.0	24.0	19.0
Chevron	25.8	19.9	17.0	12.5	8.6
Total	26.0	27.0	32.0	34.0	27.0

Table B3
Key indicators for peer group of Top 6 PPP NOCs.

	2003	2004	2005	2006	2007
(a) Net income or earnings (billions USD)					
Gazprom	4.9	5.8	7.1	13.1	14.7
Petrobras	6.1	6.4	10.2	12.2	12.2
ENI	7.0	9.6	10.4	13.0	15.9
Statoil	2.5	4.19	4.6	6.5	8.3
ONGC	1.9	3.0	3.2	3.6	4.2
OMV	0.5	0.8	1.3	2.2	2.7
(b) Number of employees (thousands)					
Gazprom	251.9	251.8	247.1	232.2	222.0
Petrobras	48.8	52.0	53.9	62.3	68.9
ENI	75.4	70.3	72.3	73.6	75.9
Statoil	19.3	23.9	25.6	25.4	29.5
ONGC	38.0	36.1	34.7	33.8	33.0
OMV	6.1	57.5	49.9	41.0	33.7
(c) Ratio earnings/employees (US dollars/employee)					
Gazprom	19,364	23,030	28,651	56,244	66,245
Petrobras	125,695	122,236	189,096	195,079	176,530
ENI	92,960	136,963	143,914	176,173	209,772
Statoil	128,671	171,482	177,983	256,591	279,714
ONGC	50,162	82,358	92,324	105,057	128,552
OMV	80,855	13,593	25,293	53,380	80,512
(d) ROCE (%)					
Gazprom	7.6	8.7	6.1	9.4	9.1
Petrobras	24.0	20.0	24.0	23.0	18.0
ENI	15.6	16.6	19.5	20.3	20.5
Statoil	18.6	23.7	27.6	26.8	17.9
ONGC	46.0	59.0	58.0	57.0	52.0
OMV	12.0	15.0	20.0	18.0	16.0
(e) Net debt to capital ratio (%)					
Gazprom	22.4	23.7	20.2	16.9	23.4
Petrobras	41.0	37.0	24.0	16.0	16.0
ENI	48.0	29.0	27.0	16.0	38.0
Statoil	22.4	18.3	15.8	18.1	12.4
ONGC	0.0	0.0	0.0	0.0	0.0
OMV	40.0	12.0	-2.0	7.0	24.0

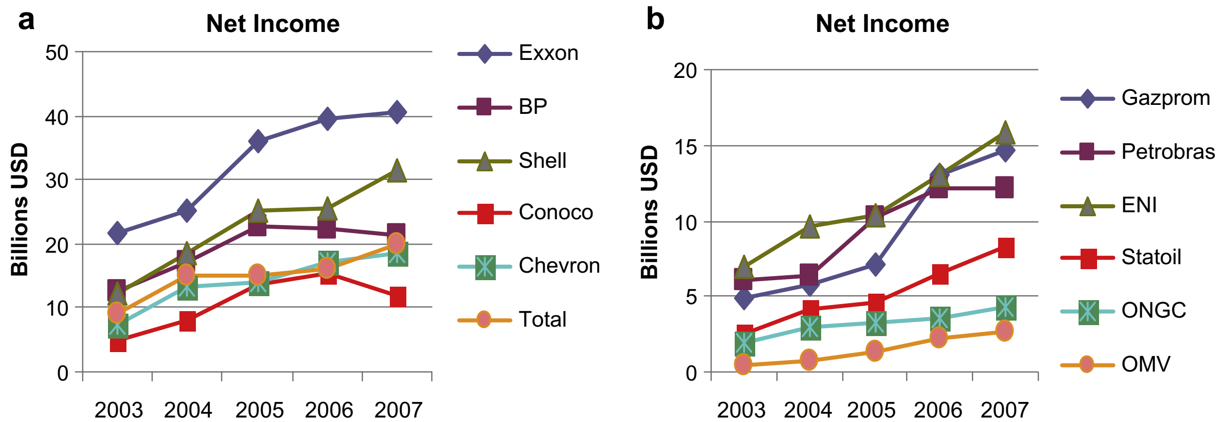

Fig. B1. (a) Net Income or annual earnings of the Top 6 IOC E&P supermajors. (b) Net Income of the world's Top 6 PPP NOCs. (Data abstracted from annual reports, and converted to USD terms, where necessary (i.e., Total and all NOCs); see Tables B2a and B3a.)

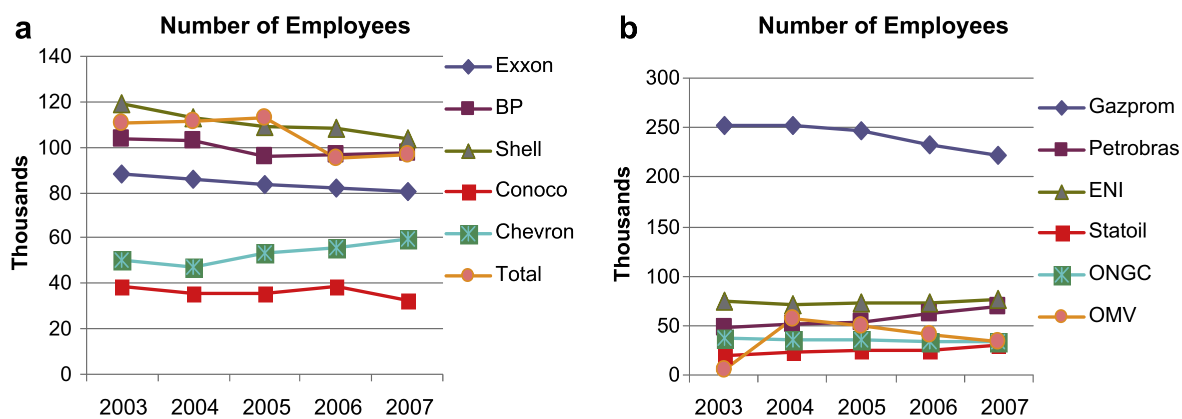

Fig. B2. (a) Number of employees at the Top 6 IOC supermajors. (b) Number of employees at the world's Top 6 PPP NOCs. (Data abstracted from annual reports (2003–2007); see Tables B2b and B3b.)

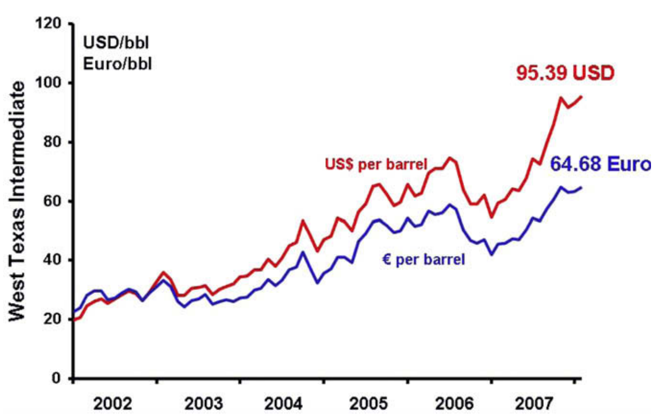

Fig. B3. Daily tracking of oil price development for West Texas Intermediate over the period 2002–2007 (red curve USD; blue curve Euros). E&P companies reporting in Euros see an apparent lower rise in revenues (data from USA's EIA). (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

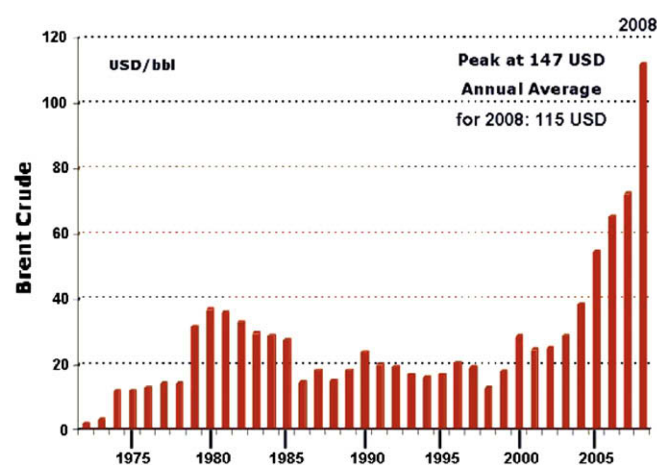

Fig. B4. Annually averaged oil price development for Brent Crude over the period 1972–2008. (Data from Europe's IEA, and BP.)

ROI (commonly perceived as risk-free, with ROI given by the ratio of interest over investment). If the Sharpe Ratio indicates a favorable value for a given level of risk exposure for the project portfolio, the company has financial leverage such that return from operations is greater than the borrowing cost. In that case the company's ROCE can be levered-up further by borrowing money for further business expansion in similarly profitable operations. This strategy is clearly implemented by OMV and ENI over the period 2006 and 2007 when they significantly increased their debt ratios (Fig. 20b). OMV's and ENI's increased gearing strategy is justified in times of profit growth. The levering-up of debt over equity (as per total capital employed in the debt ratio) benefits investors, provided the risk and return potential of the portfolio satisfies the CAPM. From the company point of view, shareholder equity is more expensive than debt financing. Assuming more debt means relatively less profit proportion needs to be passed on to the shareholders, and can be reinvested in new projects thus providing working capital for further growth of asset value. The firm's shareholders will benefit in the future when these new assets start to generate greater returns for them by the increased financial leverage.

However, short-term debt impacts the firm's liquidity. At all times, a company's liquidity as expressed by the Current Ratio (current assets divided by current liabilities) should be larger than 1. Current Ratios below 1 may imply the company's current assets (bank & cash balances, plus inventory & receivables) fall short to meet current liabilities. For the peer group companies in this study, the Current Ratios are given in Tables C1a and b and graphed in Fig. C1a and b). In 2007, ConocoPhillips and OMV have Current Ratios of 0.94 and 0.92, respectively, which demand an optimum Risk Premium in terms of ROCE, which is not delivered by these companies when measured against other companies in their respective peer groups (see Fig. 15a and b). Additionally, both ConocoPhillips and OMV are short of working capital for further new projects, because current liabilities (short-term debt and payables) exceed current assets (Tables C1a and b). This is still acceptable for investors if ROCE is levered-up over operating profitability by returns from operations (ROCE, Figs. 15a and b) that are higher than borrowing costs (as is the case for both ConocoPhillips and OMV). The financial tactic of OMV [and of BP and ENI (Fig. 20a and b) to take on more debt-leverage in 2007 (rather than equity-financing) to invest in growth markets has the objective to increase the future ROCE. But if oil prices start falling before the higher profits materialize from the new investments, these companies (OMV, ENI, BP) run a risk that shareholder returns drop steeper than of their peer companies. That is because the relatively high debt-leverage of these companies cannot be upped, as much as by their competitors, to cushion the drop in shareholder returns in times of recession (see later).

The proactive, strategic use of gearing or debt-leverage by some companies becomes evident from examining the time-series over the period studied here. Chevron and Shell systematically reduced their debt ratios over the period 2003–2007 (Fig. 20a) to suppress excessive growth of working capital that cannot rapidly be absorbed by new projects. Additionally, when corporate earnings start to slow down in a future recession market, earnings for investors can still be leveraged-up to prop-up shareholder returns to the same levels as in previous years by assuming more debt again. Chevron, Shell, and Exxon (the latter already at low debt ratio for the full 5-year period studied, Fig. 20a) can all use their relatively low debt-leverage as a tactical buffer to gear up investor returns when corporate profits start to slow in times of recession. To prevent lowering of their debt-leverage still further (over the 5-year period studied), these companies have additionally resorted to share buy-back instruments to balance debt decreases with a decrease in equity financing. Faced with a growth market (over the 5-year period of 2003–2007) and booming profits but limited project options of premium quality, these companies could not invest the cash earned fast enough to create further profit growth. Therefore, their balanced share buy-back and debt reduction strategy fits the Capital Asset Pricing Model.

In their peer group of PPP NOCs, ONGC and Statoil have maintained relatively low debt ratios (respectively, 0% and 12% in 2007) over the period 2003–2007 (Fig. 20b); others progressively lowered the debt ratio (Petrobras to 16% in 2007; Fig. 20b). These low debt ratios provide a tactical buffer for times when oil profits fall. In contrast, also for fiscal year 2007, the gearing ratios of OMV (24%), ENI (38%), and Gazprom (24%) [and for the peer group of IOCs: Total (27%) and BP (23%)] are relatively high (with ENI geared highest at 38% in 2007) (Figs. 20a and b, and Tables B2e and B3e). Their relatively high debt-gearing (as compared to their peer companies) puts these companies in less favorable positions when oil profits start to fall in times of a recession. With the State as major shareholders, PPP NOCs (OMV, ENI, and Gazprom) are more likely to keep their investors even when ROCEs start to drop in such a recession. Similarly, IOCs (Total and BP) with comparable gearing ratios (27% and 23%, respectively), cannot – in times of recession – tactically respond to please shareholders by significant upgearing. Consequently, their investors may follow the CAPM for better

Table C1(a)
Current ratios for peer group of Top 6 IOCs.

Current ratio	2003	2004	2005	2006	2007
Exxon	1.20	1.40	1.58	1.55	1.47
BP	0.91	0.97	1.10	0.99	1.00
Shell	0.90	1.13	1.15	1.20	1.22
Conoco	0.79	0.96	0.92	0.95	0.92
Chevron	1.21	1.51	1.37	1.27	1.17
Total	1.28	1.23	1.31	1.27	1.35

Table C1(b)
Current ratios for group of Top 6 PPP NOCs.

Current ratio	2003	2004	2005	2006	2007
Gazprom	1.84	3.04	3.35	2.95	2.80
Petrobras	1.45	1.46	1.42	1.38	1.12
ENI	0.96	1.08	1.12	1.26	1.12
Statoil	1.03	1.05	1.00	1.09	1.00
ONGC	2.97	2.62	3.08	2.77	2.47
OMV	1.18	1.59	1.69	1.30	0.94

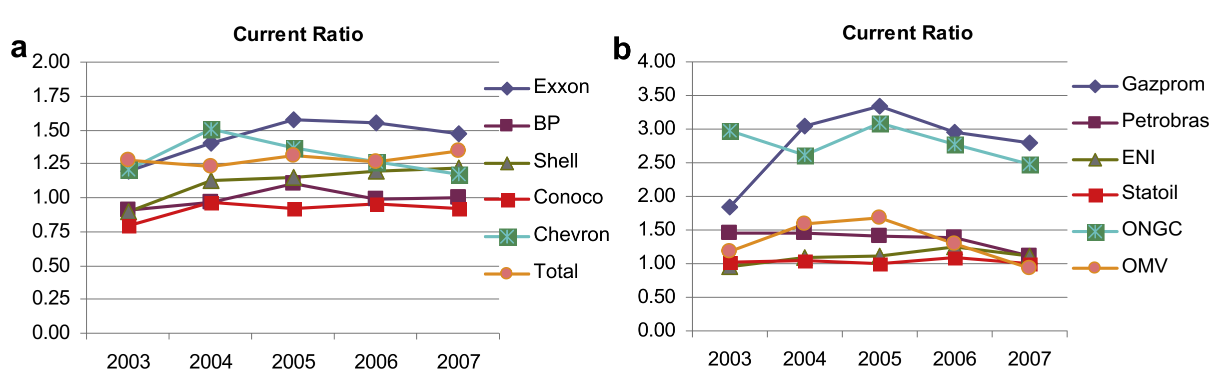

Fig. C1. (a) Current ratio for the IOC supermajors. (b) Current ratio for the PPP NOCs. (Data abstracted from annual reports (2003–2007); see Tables C1a and b.)

reward/risk opportunities elsewhere. Nonetheless, ROCE would be levered-down over operating profitability only if a company has financial leverage such that returns from operations are lower than borrowing costs. Then the CAPM bottom-line is no longer satisfied: such extreme, dismal performance generates for shareholders lower returns from operations than bank interest rates would. Risk-averse investors (even States invested in PPP NOCs) then may decide to withdraw their investments in order to reduce their risk exposure. Fortunately, all ROCE's for the company's studied outperformed the financial markets in 2007.

While ENI comes out as top Clockspeed performer of its peer group of six PPP NOCs [see Section 7 and Table 4b; based on its reporting over the 5-year period studied (2003–2007)], the dynamic risk analysis outlined here indicates that its leading position will be under particular duress when a recession hits corporate profits. ENI's high debt-gearing of 38% in 2007 deprives it from the tactical response tool of raising debt-leverage, an instrument that is fully available to its much lower-geared PPP NOC competitors (Statoil-13%, Petrobras-16%, ONGC-0%) and IOC competitors (Exxon-7%, Shell-13%, Chevron-9%) to cushion the erosion of shareholder returns in times of a recession. ENI's high debt-gearing may be a deliberate risk in its financial planning. Nonetheless, this could also become a symptom of weak management accounting in coming years.

Trademark

The term *Clockspeed Accelerator*™ is in the process of being trademarked by Alboran Media Group. The function of this trademark is to exclusively identify the source of this conceptual tool. Alboran will grant permission to any author to use, for non-commercial purposes, the term *Clockspeed Accelerator*™ in the conceptual sense outlined in this study. Companies interested in using *Clockspeed Accelerators*™ as a strategy tool for competitive advantage are kindly requested to contact the author for further information.

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Glossary of Financial Terms

***Balance Sheet**:* Financial statement that shows the company's balance of assets, liabilities and shareholder's equity at a particular time.
***Break Point**:* Upper limit of price elasticity for crude oil (CERA, 2006).
***CAPEX**:* Capital expenditure laid out to acquire or construct fixed assets.
***CAPM**:* Capital Asset Pricing Model, which leads knowledgeable investors to reduce risk exposure when capital is better held at the bank with (traditionally) risk-free ROI, unless riskier business investments become more profitable for them by yielding higher ROI's.
***Cash Flow Statement**:* Abbreviated balance of cash received and cash paid out over past performance period, resulting in a current cash position that the company has to its disposal for future activities (a.o., working capital, OPEX and CAPEX) and for generating future income. The income statement or profit-loss account shows a more detailed trading statement, breaking down revenue earned versus costs incurred.
***Cost of Capital**:* Return on project investment over the project lifecycle required by investors based on CAPM. WACC commonly specifies the (minimum) average percentage required as a bottomline return based on market values, but mostly without any significant risk premium.
***Current Ratio**:* Current assets divided by current liabilities from the annual or quarterly balance sheet. When the current ratio is smaller than 1, this may imply the company's current assets (bank & cash balances, plus inventory & receivables) fall short to meet current liabilities.
***Debt Financing**:* Raising of cash from debt provider (banks, venture capitalists, etc.) where debt assumption is at cost of periodic interest payments based on Cost of Capital model.
***Debt Leverage**:* US term, see Gearing.
***Debt Ratio**:* More specifically, the ratio of total (interest-bearing) debt to total capital (i..e., debt plus shareholder equity). Also called Gearing (UK) or Leverage (US).

***Discount Rate**:* The cost of capital over the lifecycle of the project which accounts for the time value of money according to the CAPM.
***Earnings**:* Net income available for shareholders.
***EBIT**:* Operating income or earnings (profit) after all operating costs and before Interest payments on financing costs and before Taxes.
***EMV**:* Expected Monetary Value, a NPV for a project that commonly contains high degree of uncertainty (i.e., oil exploration economics).
***Equity Financing**:* Raising of cash from share issue at cost of annual dividend pay out based on right of profit share.
***Gearing**:* UK term for the ratio of total (interest-bearing) debt to total capital (i.e., debt plus shareholder equity); synomous with US term (debt-) Leverage.
***Hurdle Rate**:* Minimum ROI requirement set by the company management that must be met for any particular project within that company before Final Investment Decision (FID) will be approved. A risk premium can also be attached to the hurdle rate if management feels that a particular project inherently contains more risk and should be compensated for by higher ROI than its common hurdle rate. Synonym with cutoff rate.
***IRR**:* Internal Rate of Return is the average rate of return over the lifecycle of the project which is exactly that specific discount rate for which the NPV equals zero. The product of IRR and NPV can be used to rank potential investment projects.
***Leverage**:* US Term, more specifically debt-leverage, is the ratio of total (interest-bearing) debt to total capital (i.e., debt plus shareholder equity).
***Liquidity**:* Measure of company's cash flow position best expressed in terms of the Current Ratio**.**
***Marginal Utility**:* The incremental change in utility associated with changes in the supply/demand ratio.
***Operating Income**:* Gross profit (revenue less cost of sales) less expenses (overhead).
***OPEX**:* Operating expenditure is money that is sunk into payroll, rent, marketing, distribution and so on. Together with working capital, OPEX is in the cashflow statement on the cost side and revenue on the income side. Cost of Capital, taxes and acquisition of fixed assets (CAPEX) may further burden the company's cashflow position.
***Optimum Purchase Price**:* Price within the price elasticity range for which product or service is perceived by the majority of customers as the most attractive alternative.
***Net Income**:* (=earnings)
***NPV**:* Net Present Value of a project calculated by gross revenue minus OPEX minus CAPEX, Taxes and Discounted Capital over the lifecycle of the project.
***Payback**:* Period of time required to earn back OPEX layout in a newly started project; reducing payback frees up cash for investment in additional projects to keep the project portfolio liquid. Payback commonly ignores the time value of money; discounted payback is more realistic and accounts for the disounted cash value in the NPV and therefore increases the duration of payback period accordingly.
***P/E Ratio**:* Share price divided by the last reported earnings per share; in fact a multiple which shows how much premium in terms of the number of years' earnings the market is willing to pay for a company's shares.
***Price Elasticity**:* Consumers are prepared to pay a premium price for a product or service as long as there is no alternative for that product or service at that price level. Premium prices are paid when the demand/supply ratio is larger than 1 and affordable and convenient alternatives are absent. The upper limit of price elasticity is reached when consumers stop buying the product or service.
***Revenue**:* Received monetary value in return for products or services sold to customers, before acounting for costs of sales, overhead, finances and taxation.
***Risk Premium**:* Part of project IRR that lies above market ROI and effectively compensates investors for any higher risk taken.
***ROCE**:* Return on Capital Employed, which is the ratio of EBIT and total capital employed. Also known as ROIC, Return on Invested Capital. ROACE, Return on Average Capital Employed uses time-averaged capital of the company as stated on balance sheets at year start end end.
***ROI**:* Return on Invesment, defined by profit (for example, in terms of EBIT) generated by total investment or capital employed.
***RONCE**:* Return on Net Capital Employed, which is the ratio of EBIT and net capital employed, which excludes capital that is owned by the company but not contributing to EBIT.
***Sharpe Ratio**:* Dynamic measure of of the excess return (Risk Premium on investment) against its tendency to fluctuate over time per unit risk assumed (the average return of a portfolio at risk divided by the standard deviation).
***Utility**:* Measure of the relative satisfaction generated in terms of consumption of products or services (or both). The utility function may focus on product volumes, financial gain, or intangible client satisfaction. The degree of increasing or decreasing utility explains the choices made by business managers and customers alike in pricing and quality of the products and services supplied and demanded.
***WACC**:* Weighted Average Cost of Capital specifies the (minimum) average percentage of return on project investment over the project lifecycle required by investors based on CAPM.
***Working Capital**:* Money tied up in operations for maintaining inventory and trade receivables (minus trade payables) required to keep the business cycle moving. A business is capital intensive when the working capital turnover (ratio of revenue and working capital) is relatively small. However, negative values occur when working capital turns negative, which may occur when receivables from customers are received earlier than payables to suppliers.