

Life cycle energy modeling

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Life cycle energy modeling for upstream field development

Rationale and methodology for use of energy efficiency as a metric in the development of upstream oil and gas production facility conceptual design

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Abstract: The upstream sector of the oil and gas industry has historically focused primarily on availability of equipment as a primary design input. With a growing recognition of global warming-related issues, including increased awareness of carbon footprints and energy efficiencies, facility design may shift from a discrete combustion turbine base case design to evaluation of central power generation and import power as best practices for certain types of facilities. This paper discusses analytical metrics, such as energy utilization (MMBTU produced vs. MMBTU required), #CO₂/boe and other values. The analysis is highly relevant to work being performed in the pre-appraise, appraise, and select project stages of a typical offshore development. The primary technique covered involves usage profiling of various options with life cycle analysis to determine potential carbon footprint mitigation/efficiency improvement. Particular attention will be paid to how these input factors affect the decision-making process during the early stages of project planning and execution.

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Moving from availability to efficiency

The upstream sector of the oil and gas industry has historically focused primarily on availability of equipment as a primary design input, which differs significantly from typical designs or operating strategies found in sectors operated on smaller margins, such as refining and chemicals. Availability here is a measure of the time a piece of equipment or system is required and able to work compared to the required time⁽¹⁾. The requirement for a high overall availability often results in installation of spare equipment, even though the peak rate period may be short compared to the life of the facility.

Efficiency (termed intensity when expressed as a percentage), defined here as the amount of energy expended compared to the energy produced by the facility, has not been a primary design metric for a few key reasons, despite the potential for savings and environmental impact reduction:

- Lack of valuation method for fuel gas in developments without access to gas markets
- Difficulty in prediction/modeling over life of field to quantify benefits
- Variability in emissions tax regimes and incentives for energy efficiency.

This is not to assert that efficiency is more important than uptime – at current oil prices, uptime return is expected to be roughly double any savings due directly to lower energy usage⁽²⁾. Happily, some of the methods discussed for improving efficiency may also increase at or least maintain benchmark availability values.

While it may appear difficult to justify design and/or operating strategy changes in an environment of relatively high oil prices, one should balance the status quo against the realization that the easiest and cheapest incremental barrel of oil to produce is typically a theoretical one from an existing facility. This production is often recognized by a non-capital expense project – it should be possible to quantify and realize some of these operational lessons during the

¹ Vorster, Mike. "Understand the Difference between Equipment Availability and Utilization". *Construction Equipment*, 1 August 2007.
<http://www.constructionequipment.com/article/CA6466790.html>.

² Cambridge Energy Research Associates. "Upstream Oil and Gas Energy Efficiency", July 8 2008 (not published).

design phase. This approach developed below to support this analysis differs from others published to date, in that energy efficiency is now used as a primary design metric, rather than as an operating facility assessment exercise.

To better understand the issue, we first need to describe energy usage in a broader context across these focus industries, identify a particular area of improvement opportunity and determine what can be changed to effect that improvement.

Energy usage trends

The upstream and midstream sectors of oil and gas are the most energy intensive industries in the world, in terms of annual heat input (see Figure 1^{(3),(4)}). Based on 2005 production of 254×10^{15} BTUs from oil and gas combined⁽⁵⁾, the oil and gas industries collectively consume nearly 20% of the fuel value of produced fluids in compression and pumping, heating and other processes.

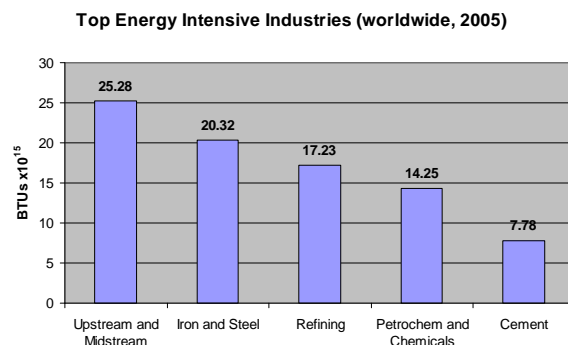


Figure 1 Industry Energy Comparison

This energy is used quite differently when compared across sectors (see Figure 2^{(2),(3)}). For the upstream sector, on average the majority of energy expended is

³ Energetics, Inc. and E3M, Inc. "Energy Use, Loss, and Opportunities Analysis for U.S. Manufacturing and Mining", December 2004,
http://www1.eere.energy.gov/industry/energy_systems/tools.html#publications1

⁴ Jogschies, Hendrik. Internal Siemens data (unpublished), 2007.

⁵ 2005 data from 2008 BP Statistical Review of World Energy,
<http://www.bp.com/productlanding.do?categoryId=6929&contentId=7044622>.

used in transportation of the fluids. This obviously varies depending on the type of operation in question; a heavy oil extraction facility in northern climes will have a greater proportion of energy dedicated to heating than an equatorial sweet oil production facility. In midstream, as one would expect transportation comprises nearly the entire energy budget. For downstream, more than 90% of energy used is for heating through a direct furnace or boiler application, for steam or other heat medium generation and for process cooling requirements.

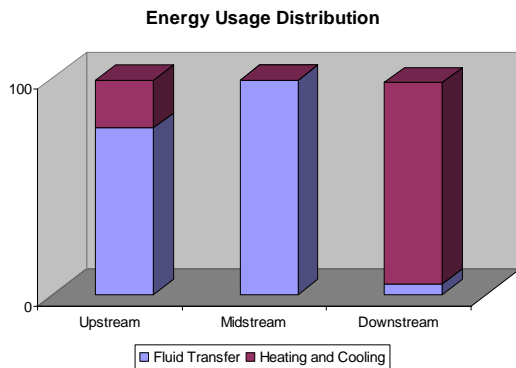


Figure 2 Energy Usage Distribution

Reduction of required work or losses in the transport segment provides the largest target for energy efficiency improvements in upstream, although heat integration may also have significant opportunities. Heat integration here is used in the downstream sense, where process heating and cooling loads are planned and matched to reduce outside requirements and excess process and utility heat is recovered for power generation (cogeneration cycle).

Design Selection Guidelines

There are several categories of potential efficiency improvements that can be applied during the design phase. Generally these can be grouped into strategies that reduce the amount of work required, those that reduce the concomitant losses in performing the work, and those that reduce fluid losses outside of energy requirements.

Note that some of these approaches will require multidiscipline support (e.g. optimization between reservoir requirements and facility design).

Reduction in required work

- Variation in arrival pressure to analyze horsepower requirements

- Smoothing of peak flow to reduce design case requirements (plateau extension)
- Waste heat recovery (whether for additional power generation or for process needs)
- Heat integration (e.g. use of cross exchangers)
- Use of drag reduction agents to reduce pressure losses in supply or export lines
- Offshore deep suction indirect cooling (suction from seawater in the thermocline)

Reduction in lost work

- Increase number of pumping/compression units required for peak rates (more flexibility as rates decline)
- Variable speed electric motors
- Variable inlet guide vanes for compressors and turbines
- Variable speed mechanical couplings (e.g. Voith Vorecon)
- Modern electric motors
- Centralization of electric generation to larger, higher efficiency co-located turbine generators
- Provision of power from outside high efficiency source (e.g. local grid driven by CCGT plant)

Non-energy-related fluid loss reduction

- Elimination of continuous vent or flare sources
- Fugitive emission surveys
- Recovery and reuse of spill event hydrocarbons

It is evident that some of the proposed alternatives will have a higher capital expenditure (CAPEX) than the traditional facility. Therefore, a method to quantify the operating expenditure (OPEX) impact and relate it back to current project dollars will be necessary for comparison. The analysis system will need to be largely software-driven to allow alternatives to be considered quickly during the initial decision-making phases of the project. Late changes to the project basis involve unnecessary rework and therefore may not achieve the inherent savings, and late project focus is typically on CAPEX savings rather than efficiency and uptime. Additionally, a framework to en-

sure commonality of reporting basis will need to be developed to support comparisons.

Full field life cycle approach

The primary concern of the process design engineer is sizing equipment and systems in accordance with a composite base case. The most conservative and simplest approach is to combine the peak rate of each fluid, though this rarely results in a practical design. More commonly, several representative cases will be prepared from reservoir model production data (e.g. high arrival temperature, low arrival temperature, maximum oil flow, maximum gas flow, maximum total liquids, maximum compressor horsepower at end of life arrival pressure, etc.). While not necessarily described as a discrete model, the combination of these sizing cases results in a composite overall design base case.

It is relatively difficult to predict what these design cases should be, however, and given time and constraints during this early phase of the project the engineer will often select the same definitions as used previously. A base case prepared to be adequate for all expected contingencies through a year-on-year modeling approach can be used to determine utility usage, emissions load, and energy efficiency at the particular combination of production rates provided by the reservoir model and should be considered to be a more exact, quantitative approach. An example of selecting various system capacities to match this composite requirement is shown in Figure 3. Note that values are presented here in a common weight value for comparison purposes only. In any case, a system requirement can be evaluated on horsepower, allocated area, direct CAPEX cost, volumetric throughput, etc., and an appropriate model year selected accordingly (or base model updated to change inputs).

For a turbine-driven reinjection gas compressor, an approach may consider trying to find the point at which a 3x50% design approach becomes more attractive than a 2x100% approach. The 2x100% approach is expected to be cheaper from a CAPEX perspective, due to having fewer discrete units, less overall weight, smaller allocated area and simplified piping. However, the 3x50% approach is more efficient in the sense that installed capacity is closer to the requirement. As the facility moves away from the design requirement for compression, the 3x50% approach provides better flexibility with less recycling required. Quantification is required to determine

whether this advantage outweighs the CAPEX increase.

The screenshot shows a window titled 'System Review' with the following data:

System	Maximum Value	User-Selected Value	Auto-Selected Year	User-Selected Year
Wellhead/Man	21.2 kips	21.2 kips	01	01
Separation	4,920.3 kips	4,920.3 kips	02	02
Crude Export	507.8 kips	507.8 kips	01	01
VRU	51.2 kips	51.2 kips	04	04
LP Comp	585.5 kips	585.5 kips	03	03
RG Comp	3,794.4 kips	3,406.5 kips	10	04
RG Glycol Dehy	451.3 kips	451.3 kips	04	01
FG Dew Point	27.9 kips	27.9 kips	04	02
Pig/Sphere	591.5 kips	591.5 kips	02	03

Additional interface elements include a 'Record:' field showing '1 of 1' and a vertical list of years from 04 to 10 on the right side of the table.

Figure 3 System Capacity Selection

In addition to providing additional data during the design phase, another important application of this approach may be to provide an ongoing operational target, similar to a nameplate processing capacity. Those involved on a day-to-day basis can make significant non-design-related improvements, such as taking trains offline when not required, driving anti-surge or capacity control valves towards minimum position, performing fugitive emission surveys, etc. This effort could be supported by real time data in an indicator or scorecard format.⁽⁶⁾

⁶ Vanner, Robin. "Energy Use in Offshore Oil and Gas Production", September 2005. [http://www.psi.org.uk/pdf/Energy Working Paper - June 2005.pdf](http://www.psi.org.uk/pdf/Energy%20Working%20Paper%20-%20June%202005.pdf)

Modeling energy efficiency

How much work needs to be done? How can this work be performed most efficiently? How can the amount of work required be reduced? How can changes be justified (i.e. quantify the financial impact)?

Establishing current costs and modeling inputs

Valuation of fuel gas and emissions reduction

In the early days of the oil industry, associated gas was seen as a nuisance and vented or flared. As markets developed to use this gas as a fuel or feedstock, reservoir drive mechanisms became better understood. The gas was sometimes used for reinjection in addition to being sold. However, in areas without access to gas markets and below the recoverable threshold for capital intensive LNG developments, should this gas be considered free?

In most producing countries, continuous flaring is prohibited, or is expected to be in the near future. Therefore one valuation could be cost avoidance of associated fines.

Assuming that a gas market becomes available due to population center shift, nearby development leading to improved infrastructure, or invention of more efficient small field technologies for transporting the gas to market, a discounted net present value based on future sale also could be determined.

Another method involves looking at the associated cost of using the gas due to emissions taxes. Norway is a common example of a country with significant reserves and a mature CO₂ tax (currently at around \$60/ton CO₂). The European Union rate for 2008-2012 is \$33/ton CO₂. Different fuel gases will provide varying amounts of carbon per standard volume, but assuming 133.759 lbs CO₂/kscf⁽⁷⁾ at the EU tax rate, this equates to about \$2.21/kscf. Compare this to the

average price for U.S. industrial gas in 2007 of \$7.59/kscf.⁽⁸⁾

For valuing the price of carbon emissions separately from the actual cost of the fuel gas itself, use of the EU value seems to be a reasonable choice (note that Norway's Ministry of Finance is pushing to join the current EU trading system.)⁽⁹⁾ However, discounting for present value may be justified for countries where no requirements are expected in the near future. Alternately there are several consultancies with a focus towards carbon pricing strategies (e.g. <http://www.pointcarbon.com/>).

Typical model evaluation

West African FPSO

A model was developed for a representative FPSO. This is a common offshore development type and provides some advantages when preparing an illustrative case, (e.g. deck area is driven by storage requirement and is relatively constant regardless of process configuration).

The base requirement for the facility modeled is 210 kbpd light sweet crude processing, 360 MMSCFD gas processing (used for fuel but primarily sent to reinjection), 90 kbpd produced water handling and 150 kbpd treated seawater injection.

Fluid data

The composite base case and all alternative variants are built directly from the fluid data. To be able to properly determine the composite case requirements, a production depletion curve is prepared, complete with major power users, such as water injection and gas injection requirements.

⁸ Natural Gas Summary, industrial gas 2007 average value, http://tonto.eia.doe.gov/dnav/ng/ng_sum_lsum_dcu_nus_a.htm

⁹ Euractive.com. "Norway to join EU carbon-trading scheme", 9 March 2007. <http://www.planetark.org/dailynewsstory.cfm/newsid/40761/story.htm>

⁷ Official Energy Statistics from the U.S. Government, Flare Gas value, <http://www.eia.doe.gov/oiaf/1605/coefficients.html>

Notwithstanding potential sensitivity studies based on variation in production rates, a representative depletion curve tool is depicted in Figure 4.

Note that this layout provides quarterly input, which is expected to be sufficient granularity to allow for development well additions to be phased correctly during the early life of the field (and for infill drilling later on).

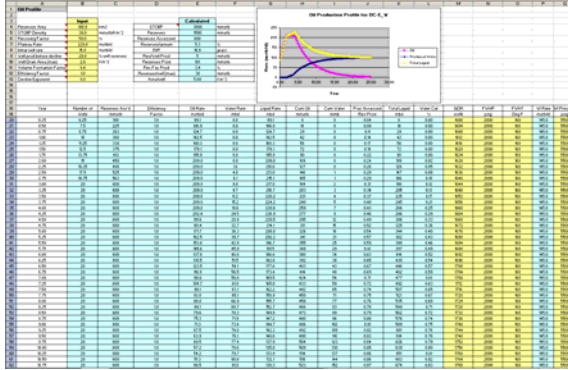


Figure 4 Depletion Curve Model

Base case preparation

Once the model has been prepared against the fluid data, the engineer must review the peak requirements of the various different systems. This can be done in a quantitative way by looking at the loads predicted by the software model over the field life (see Figure 3).

The base case model is used to set the benchmark against what other alternatives can be compared. This requires a set of values to be generated for each of the study cases. Once the base case has been updated against the asynchronous peaks determined by the software model as shown in Figure 3, annual energy production and usage can be prepared against the depletion curve actual flows (see Figure 5).

Profile Year	Field Energy Produced (MMBtu/yr)	Field Energy Consumed (MMBtu/yr)	Field Energy Flared (MMBtu/yr)	Field Energy Vented (MMBtu/yr)	Average Intensity (%)
1	244,843,796.5	4,493,828.2	0.0	0.0	1.84
2	358,992,157.0	5,260,813.2	0.0	0.0	1.47
3	358,801,729.7	5,282,425.0	0.0	0.0	1.47
4	326,596,582.0	5,098,255.2	0.0	0.0	1.56
5	294,391,434.4	4,914,085.3	0.0	0.0	1.67
6	236,171,875.5	4,500,131.2	0.0	0.0	1.91
7	189,462,597.4	4,178,789.3	0.0	0.0	2.21
8	151,988,091.8	3,901,552.0	0.0	0.0	2.57
9	121,923,673.2	3,659,251.3	0.0	0.0	3.00
10	97,804,399.1	3,434,752.4	0.0	0.0	3.51
11	78,454,175.0	3,199,339.2	0.0	0.0	4.08
12	62,931,716.0	2,945,147.4	0.0	0.0	4.68
13	50,482,079.2	2,766,356.4	0.0	0.0	5.88
14	40,491,906.6	2,455,701.8	0.0	0.0	6.96
15	32,483,902.1	2,336,287.3	0.0	0.0	7.19
16	26,061,725.0	2,235,902.1	0.0	0.0	8.58
17	20,911,422.5	2,143,486.8	0.0	0.0	10.25
18	16,778,303.2	1,981,168.0	0.0	0.0	11.81
19	13,466,715.3	1,930,849.2	0.0	0.0	14.34
20	10,811,066.5	1,889,093.6	0.0	0.0	17.47
Total Field	2,733,849,258.2	68,607,216.7	0.0	0.0	2.51

Figure 5 Energy Efficiency Profile

Evaluation metrics of potential interest are the minimum energy intensity (see Figure 6) and CO₂/BOE (see Figure 7). These provide a measure of the maximum efficiency of the particular design arrangement for a given depletion profile with respect to energy usage and CO₂ emissions and could be used in a comparison framework against the CAPEX difference for the various arrangements.

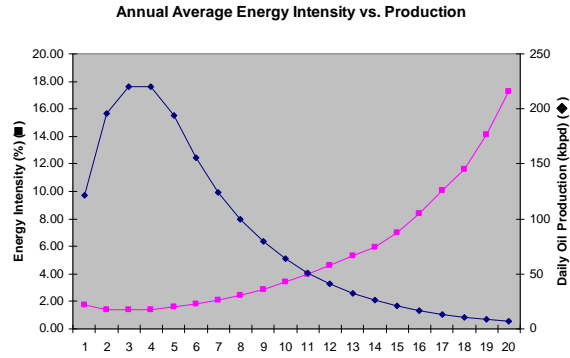


Figure 6 Energy Intensity vs. Production

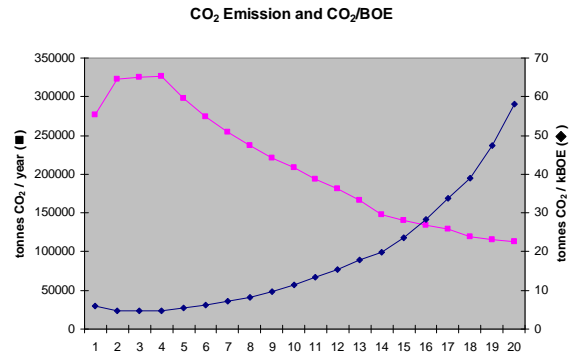


Figure 7 CO₂ Emissions and CO₂/BOE

From the emissions perspective, plotting against production provides another way to visualize the drop in efficiency as the facility moves away from the peak throughput point (see Figure 8). With the calculated values on similar scales (80% of min value to 120% of max value for each), the gap between the plots after year six provides a measure of the marginal drop in efficiency.

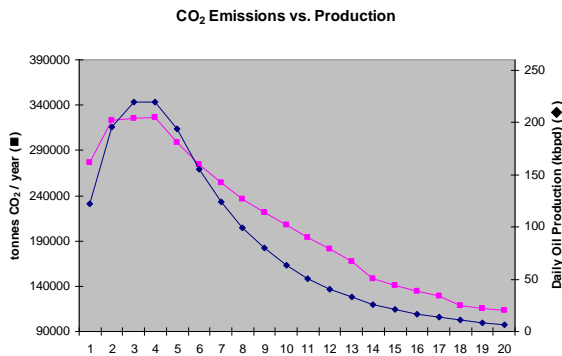


Figure 8 CO₂ Emissions vs. Production

Alternatives studied

The following alternative cases all consider the same depletion profile for illustrative purposes. Power generation and reinjection gas compression systems peak requirements have been selected on the basis of maximum horsepower. Other system peaks have been selected automatically by the software model on a weight basis.

- BASE – FPSO base case
- SMALL – change 2x50% LM2500+ driven reinjection gas compressors to 2x50% LM2500 driven reinjection gas compressors (available HP reduction, requirement is now 94.5% of site rated available HP).
- SPARED – change 2x50% LM2500+ driven reinjection gas compressors to 3x50% LM2500+ driven reinjection gas compressors (improve availability).
- FLEXI – change 2x50% LM2500+ driven reinjection gas compressors to 3x33% Titan 130 driven reinjection gas compressors (improve availability and late life flexibility).
- ELEC – change 2x50% LM2500+ driven reinjection gas compressors to 2x50% VSD electric motor driven reinjection gas compressors (power generation forced from 3x50% with total load of 18.9MW attached to 4x33% with total load of 60.8MW attached).
- IMPORT – change 2x50% LM2500+ driven reinjection gas compressors to 2x50% VSD electric motor driven reinjection gas compressors and have power generation requirement of 61.5MW replaced with import power from shore. Remaining fuel gas users are inert gas generation and low pressure compression.

Model comparisons

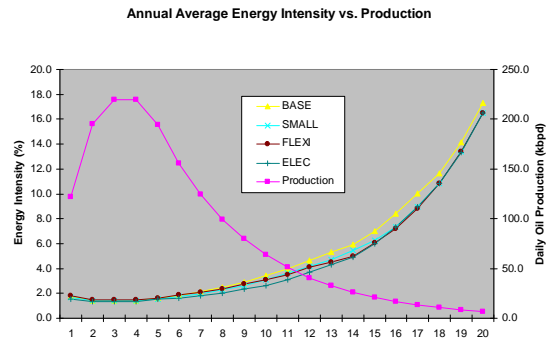


Figure 9 All Models Energy Intensity vs. Production

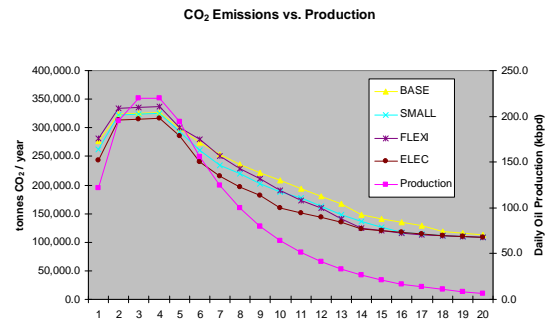


Figure 10 All Models CO₂ Emissions vs. Production

The ELEC model shows the best efficiency and emissions performance of the cases studied. Based on a combination of the fuel usage and emissions as modeled, and using a value of \$3.795/MMBTU for fuel (based on 50% of pricing above and 1000BTU/scf) and \$33/ton CO₂ for emissions, and annual inflation of 2.5% for all pricing, a simple NPV calculation can be prepared for the difference between the BASE and ELEC cases. This indicates an NPV of \$47 million (\$31.4 million for fuel gas savings and \$15.6 million for emissions avoidance), which can be evaluated against the expected CAPEX increase from the BASE model. When combined with expected improvements in uptime, for the modeled case an all electric drive approach may have significant benefits vs. the traditional design with dedicated gas turbines at each major power user.

Note that SPARED and IMPORT have not been included in the graphs. SPARED produces the same

efficiency curves as BASE - the improvement in availability requires generation of a RAM model to support the increased CAPEX. IMPORT provides a much lower local emissions and fuel usage, shifting the burden to shore based power plant with higher expected efficiency (even with transmission and conversion losses). This needs to be balanced against the CAPEX impact of powerline installation, changes in the production facility design and other factors outside the scope of this paper.

Conclusion

Energy efficiency improvements and emission reduction provide directional incentives in terms of OPEX. Modeling of these impacts during the design phase may bring to light financial drivers not normally considered by the project team. For certain project types, significant project savings may be available. In order to quantify these costs during early phases of project definition, a life cycle-based energy model can be employed. For the West African FPSO example developed, an OPEX net present value savings of \$47 million was established for an all electric drive approach when compared against a traditional discrete gas turbine design, based solely on fuel gas and emissions reduction.

Further development work

Integrate more sophisticated financial analysis within model environment.

Combine financials with risks and probabilities of various events (e.g. changing product prices, excessive inflation, etc.).

Ensure depletion model includes effect of gas cycling in gas lift or gas reinjection situations and water influx for water injection cases.

Complete OPEX model with overhead, maintenance, other consumables, logistics, modifications and turn-arounds, well workovers and decommissioning costs.

Observations

As with any comparison process, one of the important constraints is to ensure that a common basis has been used. Additionally, there are other phenomena which may be masked by the available data. For this reason, several potential misunderstandings are listed below.

- BOE vs. MMBTU/yr.⁽¹⁰⁾ Gas utilized for fuel on a platform can be reported on a BOE or heating value basis. Depending on the heating value of the fuel gases in use, a BOE comparison across fields or used as a benchmark may introduce some confusion. A common conversion of 5.8kscf gas to 1 BOE is similarly dependent on gas calorific value (it uses 1000 BTU per SCF), as a BOE has a standard definition of 5798615.481 BTU.
- BTU basis should be standardized - several definitions exist (International Steam Unit definition of 1,055.05585262 BTU = 1 Joule has been used in this paper).
- Drivers vary by region, so the engineer should expect alternatives to present different values depending on the development criteria. As an example,⁽¹¹⁾ an onshore Canadian heavy oil development combines high direct energy intensity requirements, a near Arctic environment, and a relatively high market price for gas. These factors would combine to make energy efficiency improvements significantly more valuable than a similarly sized facility in places such as Venezuela.
- Figures for carbon tax can be reported in \$/ton of carbon or \$/ton of CO₂. There are 27.3 tons of carbon in 100 tons of CO₂.
- If an agreed basis can be prepared to put a current dollar value to improved uptime percentage, it is conceivable that a more efficient process arrangement would be selected despite increased CAPEX and otherwise insufficient OPEX savings. A RAM study could be prepared to highlight the uptime differences between the two designs.

¹⁰ Svalheim, Stig, and David King. "Life of Field Energy Performance". 2003, SPE Paper 83993.

¹¹ Cambridge Energy Research Associates. "Upstream Oil and Gas energy Efficiency: a Critique of the Siemens Approach", July 8 2008 (not published).

Abbreviations

CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
FPSO	Floating Production Storage and Offloading
KBPD	Thousand Barrels Per Day (oil or water volumetric rate measurement)
MMSCFD	Million Standard Cubic Feet per Day (gas volumetric rate measurement)
NPV	Net Present Value
OPEX	Operating Expenditure
RAM	Reliability And Maintainability Study

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