Management of mature fields - a key for the energetic future

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Abstract

Mature fields are both a major medium term challenge to delay oil rarefaction (mobilisation of additional incremental reserves) but also a shorter term challenge to boost production and to cope with an increasing demand (1,5% per year) which should reach between 115 and 120 Mbbls/day in 2030.

Three fundamental relevant criteria (reservoir maturity, degradation of asset integrity and maladjustment between needs and means) can be used to define maturity :
-The reservoir maturity (more water, more gas, less pressure) is linked to the natural evolution of the conditions prevailing while extracting oil,
-The degradation of the asset integrity has to be understood in a broad sense (integrity of the equipment but also integrity of the methods as well as quality of human resources)
-The progressive maladjustment between needs and means results both from an increase of the operating envelope (envelope of needs) and a decrease of the functioning envelope (envelope of means). Divergence between needs and means will generate bottlenecks with sometimes heavy consequences on production.

Management of maturity criteria are quite often made more difficult by worsening factors (technical, issued from new regulations, contractual, financial, lack of logistic means).

Along those lines, short, medium and long term mature fields management will be addressed through a number of examples:

-production and HSE risks associated with asset vulnerability (Gabonn North Sea, Indonesia)
-tie back of several gas fields on mature surface facilities (North Sea)
-redevelopment of a mature asset using an on-shore centralisation strategy (Gabon)
-stop flaring and valorisation of associated gas using conventional or micro GNL (Congo, Cameroun)

Management of mature fields - a key for the energetic future

Two « risky » challenges

The world will be confronted over the next 50 years to **two major energetic challenges** with possible drastic political, economical and social consequences.

The first (short term) challenge will be related to **oil production**. To cover the 2030 oil demand (about 115 Mbopd on the basis of an increase of the demand comprised between 1,5 and 2%) the "proved" part (declining basement and production corresponding to identified new projects[1[1]]) has to be complemented by a "normative" part relying, on one hand, on exploration on the other on the capacity to increase the recovery factor of the existing fields. Without these two major contributions the production would be characterised by a peak oil below 100 Mbopd located between 2015 and 2020 the new projects and the unconventional oil (sources of growth) being not able to offset the decline of the basement.

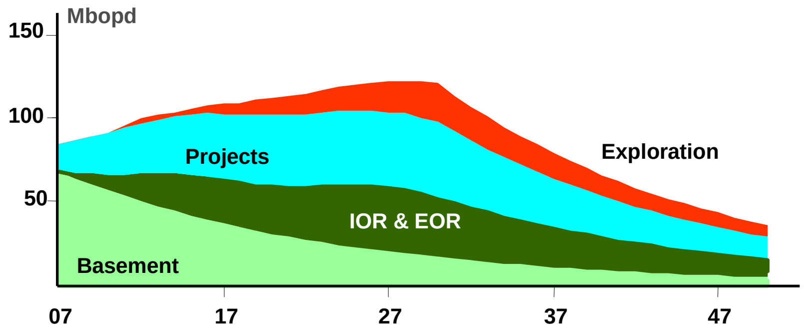

Figure 1– Breakdown of world production (source : US DOE 2006)

The medium term challenge will be related to **oil reserves**. Assuming that ultimate reserves are in the range of 2200 Gbbls (1000 Gbbls already produced + 1200 Gbbls to be produced by 2050) with a mean recovery factor comprised between 30 % and 35 %, an additional 5 % of recovery would result in more than 300 Gbbls of additional reserves, that is more than the remaining exploration potential estimated by ASPO[2[2]] to be only 250 Gbbls.

However, even if huge incremental reserves are associated with increased recovery factors of Mature Fields, the rate and the cost of getting them into production appear always very challenging. Producing countries and major International Companies are therefore faced to number of strategic and difficult choices between development of new projects and reengineering of Mature Fields.

On the basis of equal initial size, the start-up of a new field will always bring much more instantaneous production than revitalisation of a Mature Field. Consequently and even if the investments required are always much less than those associated with a new project (10 to 25% of initial CAPEX), the marginal cost per additional barrel can be high compared with the one associated with a new project.

From a contractual point of view, the structure of PSA strongly encourages investment in fields which have already been in production for several years, for which past investments have been largely recovered (cost oil available) and future production is very much more foreseeable. Investments can in addition be encouraged by some forms of PSA in particular uplift of CAPEX (investment recovered at a level above 1) together with production allowance (bonus for every barrel produced above a reference profile). However, a close expiration of licenses heavily penalise the reengineering of Mature Fields stating that without a sufficient

[1[1]] These new projects are, in particular, the deep water fields in Africa and in Brazil, the reserves associated with the giant fields in the Caspian Sea area, as well as the launch of some new projects in Alaska and Middle East.
[2[2]] ASPO is ASsociation for study of Peak Oil & gas - www.aspo.com

visibility (at least a decade) a Joint Venture will hesitate to invest. A lot of producing countries play today a risky game by prolonging uselessly negotiation before extending/renewing licenses. If justified by a short term view such decision could sharply slow or even defer certain redevelopment plans, and hence could eventually penalise recovery. For we must remember that, unlike a new project, revitalisation of a Mature Field can't wait!

The three maturity criteria

To be properly produced, a drop of oil will need sufficient mechanical energy to escape from the reservoir and overcome all the barriers it will meet during its very long travel towards the surface. This energy can be natural (pore fluid pressure) but also provided artificially (water injection, gas lift, surface pumping). In the reservoir, the oil drop will have to overcome rock barrier, viscous forces as well as capillary barriers. In the well vicinity, rock properties can be highly degraded and act as a very detrimental obstacle whereas in the well itself the oil drop will have to overcome gravity forces as well as hydrodynamic effects linked to multiphase flow. Across the surface facilities where oil will be separated from residual gas and water, additional artificial energy will be provided through numerous pumping units.

Even if appearing as a degradation factor, age cannot be considered as a relevant factor to properly define asset maturity. We propose below a definition based on three criteria: reservoir maturity, progressive degradation of asset integrity and progressive maladjustment between means and needs.

Reservoir maturity is linked to the natural evolution of the conditions prevailing while extracting oil from the reservoir. From step to step, pressure and fluid saturations will be profoundly modified, oil will rarefy whereas water and gas production will increase. The oil drop will penetrate within successive production envelopes in which with less and less natural energy it will have to overcome higher and higher natural barriers. Depending on initial (pressure, fluid saturations) and production conditions (depletion rate), reservoir maturity can appear quite early or much later.

Parallel to the reservoir maturity, time will have in most cases a detrimental effect on the exploitation conditions of the asset namely on the asset integrity[3[3]]. Integrity has to be understood here in a broad sense : integrity of the equipment (corrosion, fatigue of rotating machines, obsolescence[4[4]] of old equipment), integrity of the methods (technical documentation, management systems) as well as integrity of human resources (competences, training, motivation). We will see that the three integrity components play a major role when performing the mapping of a mature asset.

An asset is initially built with a functioning envelope (envelope of means) slightly oversized with respect to the operating envelope (envelope of needs).

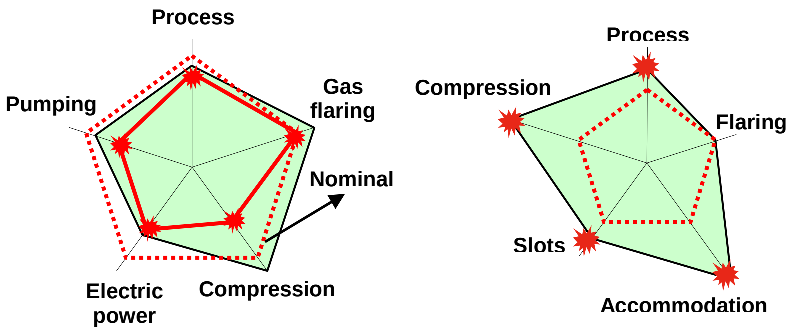

Figure 2 – Exploitation (left) and re-development (right) bottlenecks

[3[3]] Asset integrity is defined as follows : asset reaching its goals in terms of production and recovery providing a certain number of financial (production and recovery have to generate sufficient profits), HSE (any operation must respect safety and health of personnel as well as environment) and sustainable development (local content, integration of oil activities in local economy) constraints

[4[4]] Obsolescence of equipment is defined from three criteria : old equipment, no more spare parts and no more competencies to properly maintain the equipment.

With time, the exploitation conditions will change reservoir maturity bringing additional needs (increase of the operating envelope) whereas degradation of asset integrity will reduce the available means (decrease of the functioning envelope). Divergence between needs and means will generate "exploitation bottlenecks" (
Figure 2) with sometimes heavy consequences on production. Quite often, these exploitation bottlenecks will be treated through routine or non routine maintenance actions but sometimes they can require expensive reengineering projects.
Bottlenecks can also result from redevelopment projects for which additional reserves (improved recovery of an already developed reservoir, development of a satellite or near by exploration) are tied back to existing installations. These bottlenecks called "redevelopment bottlenecks" are generally much larger than exploitation bottlenecks and will always require partial or complete review of the initial development scheme.

Example

Figure 3 presents a remarkable example of exploitation bottleneck following lack of low pressure gas for gas lift purpose. Most of producing wells of the asset are gas lifted and spread over a surface of 120 km^2 whereas all compression is installed on a same platform located in the south. Compressors are supplied by low pressure gas coming from the southern sector (field 5) as well as from one other platform (field 4). Downstream the compressor, high pressure gas (130 bars) is sent to all fields. Gas lift network being open, excess of gas is flared on each satellite platform.

Over the next years, LP gas supply will continuously decrease (1 Mm^3/day in 2003 vs 200 km^3/day in 2011) whereas at the same time HP gas needs (more wells to be gas lifted) will increase from 850 km^3/day to 1,3 Mm^3/day. Removing the bottleneck requires to lay pipes (dotted lines of **Figure 3**) to bring back low pressure gas from Field 1 & 2 where large amounts are flared

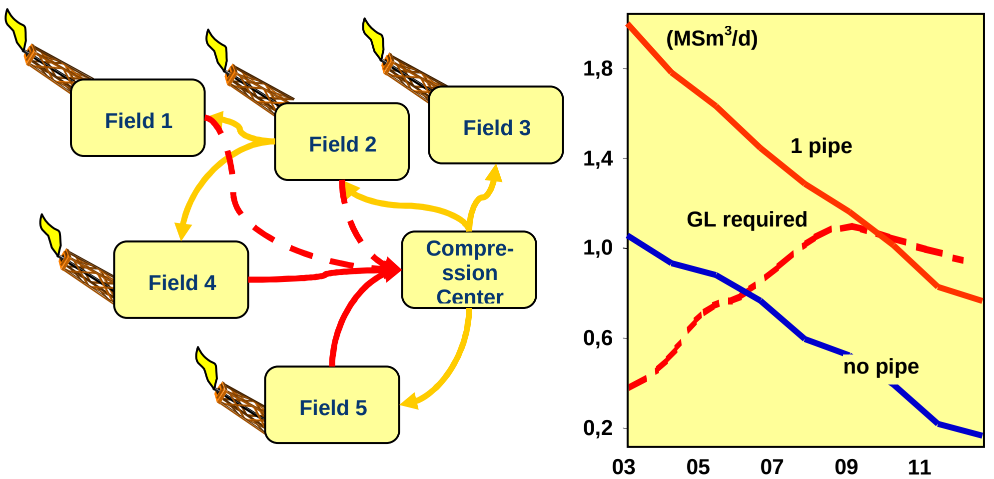

Figure 3 – Bloc 3 gas lift network

Worsening factors

Worsening factors can reinforce or make more difficult the management of the three maturity criteria :

Natural parameters such as abnormal pressure, temperature or fluid compositions (sour gas, wax in oil or specific ions in production water) as well as complex reservoir geometry (multilayered or faulted reservoirs) will generally accelerate the maturity broad sense, Mature installations generally highlight large gaps compared to recent procedures and regulations in particular with respect to safety and environment (i.e. stop flaring policy) imposed by international companies and host countries. Sustainable development constraints such as imposed local content can introduce additional difficulties particularly in countries where people are not properly trained in conventional oil disciplines,

The contractual terms agreed between a Joint Venture and a host country can also introduce additional constraints. As already mentioned in the previous paragraph, the proximity of the end of a licence generally corresponds for the Joint Venture to the stop of any kind of investment with detrimental consequences on reservoir maturity and asset integrity. The same applies to a low barrel price.

Finally, certain logistics constraints (availability of drilling rigs, wire line, slick line, snubbing or coiled tubing unit) can delay or even cancel Non Routine Works or re-development campaigns particularly in a tight market situation (high barrel price) when logistics means are in competition with new large profitable projects.

Mature management system

The proper management of a Mature Asset will have first to identify the red alerts (mainly consisting in exploitation bottlenecks) which could endanger the production of developed reserves already booked in the company portfolio (defensive strategy) before initiating an offensive strategy in view of developing new reserves generally with conventional technology but also possibly with innovative variantes. The process is however rarely linear, defensive and offensive strategies being generally carried out at the same time. The merge between “short term securing[5[5]]” and “medium/long term redevelopment” have to be mixed within a coherent driving scheme integrating all space (asset to be regarded globally) and time (future challenges to be fully considered even if not yet decided) components. The resulting methodology called Mature Management System is presented in **Figure 4**.

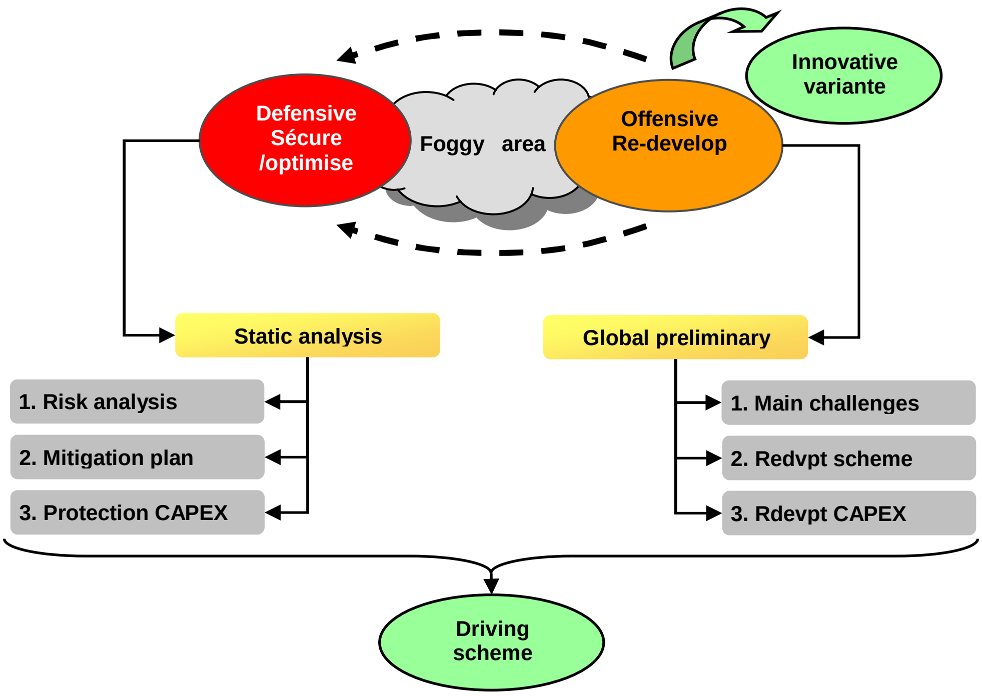

Figure 4 - Mature Management System

[5[5]] The defensive strategy is not only devoted to secure the developed reserves but also considers any light opportunity making it possible to increase these developed reserves. It covers the optimisation of gas lift and water injection, safety work over and possibly some in fill wells drilled from existing slots.

Static analysis

Securing developed reserves requires first of all establishing a clear view of the asset in its current sate by analysing precisely its position with respect to the three maturity criteria. The proposed methodology which is similar to that commonly used in risk assessment follows a workflow including five successive steps : segmentation, vulnerability, impact, risk and mitigation.

A functional analysis in view of decomposing the asset in key systems. Both production systems (reservoir, production, injection and PWRI wells, oil/gas process & export, water injection, power generation, pipes and flowlines) and support systems (structures, control/command, HSE, accommodation and logistics) have been considered,

Each system is then qualified in terms of vulnerability. Widely used in various industries (steel, cars, chemistry), the vulnerability of a dedicated system can be interpreted as the probability of occurrence of detrimental events penalising both production and HSE performances. Depending first of all on the intrinsic state of the system (i.e. the electrical integrity of the welding tool in **Figure 5**), the vulnerability of a system can be (positively or negatively) reinforced by the way by which the system is operated (right helmet, right gloves, operator well trained). The latter are so called "protections". The global vulnerability o a system is calculated as the product of its intrinsic vulnerability times the quality of its protections.

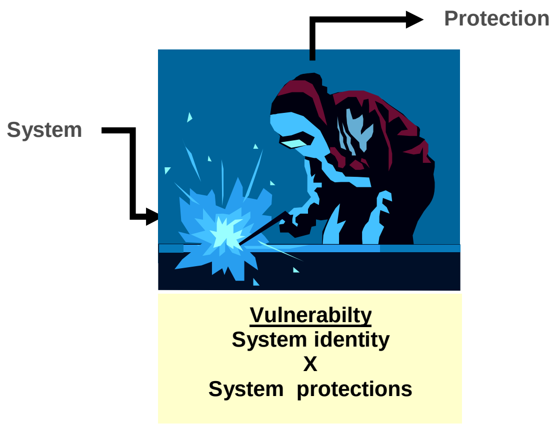

Figure 5 – The vulnerability concept

Coming back to maturity definitions (reservoir / asset integrity / maladjustment means & needs), the vulnerability of a dedicated system of a Mature Asset can be appreciated by considering its identity card on one hand (two technical criteria namely maturity and capacity) and its protection card on the other

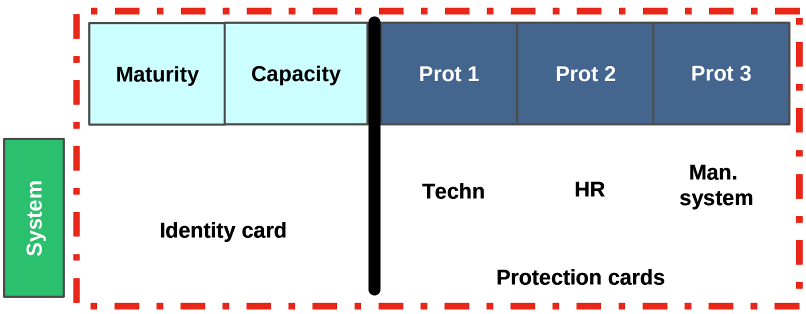

Figure 6 – Decomposition of vulnerability
Identity card : maturity and capacity
Protection cards : technical, HR and Management Systems.

In line with the definition of Asset Integrity, three types of protections namely technical processes (P1), human resources (P2) organisation & management systems (P3) have been considered. For a given system, maturity, capacity and each of the three protections are evaluated through a pre-established grid addressing a series of questions to be ranked between 1 (very good) and 5 (maximum degradation). The ranking is estimated using relevant physical indicators then results are crosschecked through interviews with dedicated specialists. The various questions are then merged within a global note and the global vulnerability (also called “composite vulnerability”) of each system is calculated using empirical formula.

Impact of a system is defined as the loss of potential corresponding to a full (100%) vulnerability. For direct production system such as reservoirs, wells or export pumps, it will correspond to the amount of potential managed by the dedicated system (current global reservoir potential for a reservoir or set of wells, oil potential of the asset for oil export pump, gas potential of the asset for gas export compressors). For indirect production systems determination of the impact can be more or less complex. For power system it will correspond to the whole potential (no more production without electric power) whereas for water injection or gas lift systems, potential deficit will be estimated in relation with reservoir (case of zero injection) and well specialists (no more gas lift available). Finally, for support systems such as structures, HSE or logistics, the impact is more difficult to estimate. However, in many cases, it can be associated with a total loss of potential : no authorisation to resume production with a fully degraded HSE system, impossibility to resume production with total unavailability of logistics.

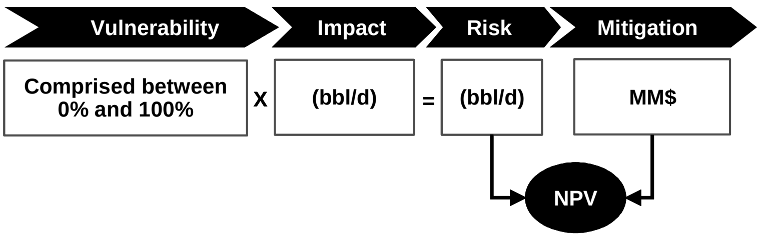

Figure 7 – Global workflow of MMS project

Calculated in terms of bopd as the product of vulnerability by impact, the risk associated with each system will allow proposing a prioritised action plan in view of mitigating the vulnerability of the most risky systems. Depending on the case, actions will be focused on maturity (i.e. replace obsolete compressors), capacity (i.e. add a new compressor) or protections (i.e. launch a new M&I plan, recruit M&I specialists). Protection CAPEX associated with the prioritised mitigation plan will then be quantified and spread out in time according to a realistic planning. All mitigation actions being not performed at the same time, the production at risk can be integrated during the unmitigated period and used to estimate the profitability (NPV) of given mitigation actions.

Example

The example presented below deals with a Mature Asset the segmentation of which is presented in Error! Reference source not found.. It produces from two main sectors 1 and 2. Production is shared between surface production (most oil fields) and subsea production (most gas fields). Sector 1 is supplied by two oil fields. Effluents are then mixed and sent via two Multi Phase Pumps (MPP) to sector 2 to be further processed. A single field (oil 2 - Error! Reference source not found.) of Sector 1 is supported by water injection (treatment and pumping facilities located on sector 2). Sector 2 is supplied by oil, gas + condensate and dry gas fields. After being processed on sector 2, oil and gas are both exported.

Static analysis

The static analysis can be presented either using a vulnerability vs impact charts (most risky systems are located in the upper right corner) or directly using ranked risk bar charts. The results (**Figure 8**) highlight that the oil 2 from Sector 1 is by far the most risky reservoir

system due both to its high vulnerability and its large impact (70% of the oil production of the whole asset). Current risk is estimated at 6,5 kbopd. This reservoir suffers from a high degree of maturity (depleted reservoir with high BSW, insufficient water injection, questionable sweeping efficiency, permeability contrasts and scaling in the reservoir) as well as from very deteriorated technical protections namely a deficient global monitoring (most permanent downhole gauges out of service, old seismic acquisition not recently reprocessed, poor availability of the test separator, lack of wire line monitoring because of lack of space on the deck and lack of accommodation), a lack of reliability of the production reallocation (flowmeters measuring only global export) and a very poor reservoir model (complex slumped structure and PVT, unreliable history matching). The high vulnerability of the reservoir system, is reinforced by degraded inflow (scale formation in the Reservoir Well Interface) and outflow (low BHP, liquid loading) performances. Following lack of space and accommodation, the well system also suffers from a lack of well intervention.
With respect to surface facilities, power generation, export gas (medium vulnerability but very high impact), Multiphase Pump (medium vulnerability and impact) and Water Injection System (high vulnerability but low impact) appear as the most risky surface systems.

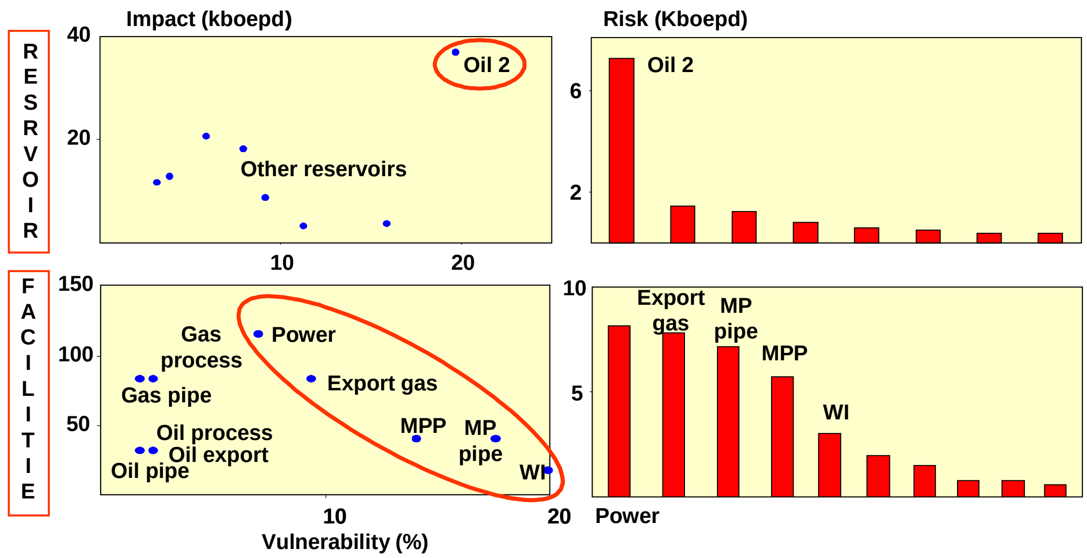

Figure 8 – Results of the static analysis

Actual events (recent failure of two turbines and 1,5 MMbpd of unplanned shortfalls in 2006 associated with Multiphase Pumps) confirm the relevancy of the static MMS analysis. Looking in more details at the surface systems, vulnerability originates from various origins. Electrical generation is in over capacity (80 MW available from four turbines, only 40MW – 2 turbines- required for normal operation) but strongly degraded (less than 85% of total availability) and close to obsolescence whereas export compression originates its vulnerability from capacity problems (capacity of 16 Mm^3/d for current production with peaks >14 Mm^3/d). Export capacity problems should be reinforced in the future with the tie back of new satellites. The high vulnerability of Multi Phase Pumps (availability less than 85%, very heavy shortfalls) is caused by the global conception of a high tech and innovative concept suffering from mechanical problems but also from a progressive gap between the initial specifications of the pump (Gas Liquid Ratio < 20) and current operational window. Finally, the water injection system suffers from a lack of maintenance which has induced a deterioration of the de-oxygeneation tower as well as the water injection pipe. Both being corroded, injected water is strongly polluted by corrosion particles plugging the reservoir.

This example clearly highlights the relevancy to decompose the vulnerability in maturity, capacity and protections.

Medium term challenges

For the next ten years, the considered asset lies on the following challenges :

Blow down (full decompression of the reservoir below the bubble pressure) of oil 2 is planned to begin between 2010 and 2012. It will be associated with a massive gas production and a sharp increase of the GLR. The blow down brings several unknowns (how massive gas production can mobilize residual oil, how remaining injected water can possibly penalize the final recovery ?) as well as major technical constraints with respect to pressure (how to increase downhole pressure and lower well head pressure) and Multi Phase Pumps (how to accommodate the huge increase of GLR),

Manage the medium term production of depleted gas fields which are subjected to water influx with a high risk of rapidly killing the wells,

Tie back of additional decided and not yet decided (near by exploration) gas satellites,

Coherence between short term and medium term actions

The relevant management of the asset requires a global strategy to meet short term mitigation actions in view of securing developed reserves with medium/long term actions devoted to develop additional reserves. For the next ten years the following action plan (two main periods) has been proposed.
2008/2011 : mitigate vulnerability, prepare field blow down & tie back a gas satellite

Perform major maintenance works to restore the integrity of water injection system (electrochloration system, sand filters, internals of the de-oxygenation tower and cleaning of the corroded injection pipe,

Revisit the reservoir model of oil 2 including the reprocessing of seismic data to improve the structural model as well as an extensive study of the behaviour of the wells in view of improving the petrophysical “filling” of the various layers,

Reinitiate monitoring to properly history match this new model by restoring surface equipment and downhole permanent sensors in subsea wells. Reduce well intervention backlog (well works but also wire line monitoring) will require the mobilization of a temporary accommodation barge to solve the acute accommodation problematic,

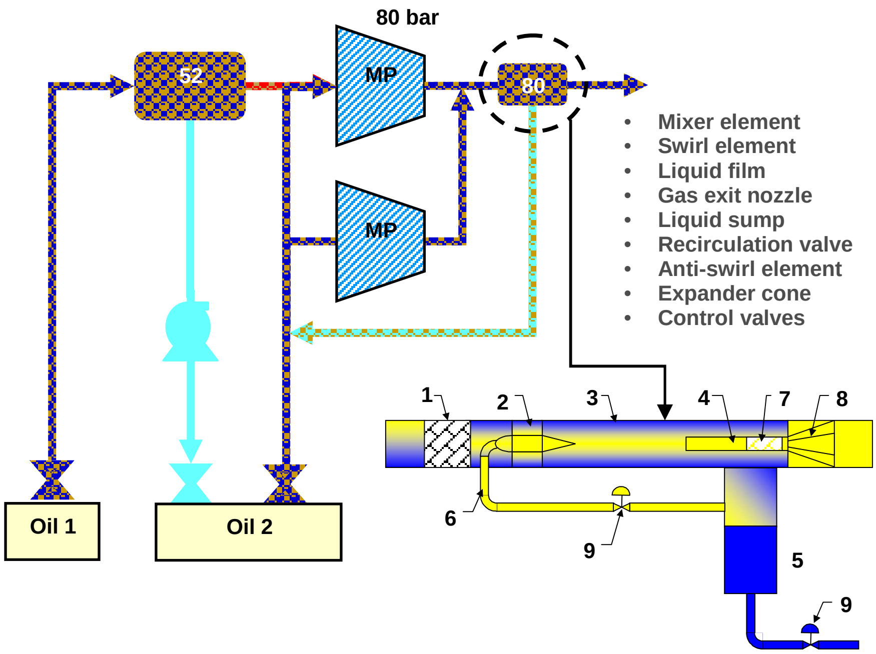

Figure 9 – Deliquidizer technology

Adapt MPP to the progressive increase of gas production to secure current oil production and accommodate future blow down. Apart the change of internals, the proposed solution consists in implementing an in inline de-liquidizer (**Figure 9**) downstream the pump to extract liquid which will be re-circulated upstream in view of maintaining the inlet GLR below the requested limit. Deliquidizer has the advantage of its very reduced space which is a major constraint on these facilities. It is however currently not yet field proven.

Revisit the current electric power system (overcapacity but low average availability) to adapt it to the progressive increase of needs passing from 38 MW in 2007 to nearly 50 MW in 2010. The current 4x50% situation (two spare turbines) will evolve towards a 4x33% situation (a single spare turbine). The chosen strategy could be either a refurbishing of existing turbines keeping a 4x33% or the implementation of 3x50% new turbines,

Develop a major gas + condensate field (G/C 3 - Error! Reference source not found.) with two subsea high productivity wells tied back to the main facilities via an existing gas pipe producing G/C 2 (Error! Reference source not found.). However, undepleted new G/C 3 and depleted G/C 2 cannot be produced commingle in the same pipe. This explains the shutdown of G/C 2 between 2008 and 2012.

Treat properly water influx in gas wells by progressively implementing concentric gas lift. The proposed system consists in placing a spool insert between the tubing hanger and the X-mas tree with a suspended piece of coiled tubing. The gas is then injected inside the coiled and the well is produced within the annulus space between coiled and existing tubing.

2012 to 2018 : manage blow down and revise gas production network

Stimulate the blow down of oil 2 by implementing on producers artificial lift process proposed for gas wells. This would require (Error! Reference source not found.) to tie back a new gas pipe at the outlet of the export compression,

Lower well head pressure to fit against water loading in depleted gas wells and stimulate the blow down of oil fields. If feasible on most gas fields, lowering well head pressure poses acute problems on sector 1 due to the Multiphase Pump. For instance, compared to 50 bars, lowering the pressure to 30 bars nearly double the µphase flow whereas a WHP of 10 bars (nominal pressure of LLP separator) would multiply the µphase flow by a factor 5.

Re-route G/C 2 & G/C 4 to Sector 1 in view of reducing the duration of the shut down and allowing the possible connection of additional gas field G/C 5. This will require laying a new gas pipe to Sector 1. Depending on the pressure level of the global multiphase system, the line could be connected either downstream or upstream the pumps. However, G/C 2 which will bring to Sector 1 large amounts of additional gas should impact the design of the deliquidizer.

Anticipate the future needs in compression. The available maximum export compression today is in the range of 16,5 Mm^3/d with an availability of 97% to be compared to an effective production of 14,5 Mm^3/d. The tie back of decided (G/C 3) and undecided (G/C 4) fields plus gas lift needs (1 to 1,5 Mm^3/d) could require to revisit and debottlleneck in a near future export compression capacity which could reach a peak exceeding 20 Mm^3/d in 2013/2014.

Merging short (secure developed reserves) and medium/long term actions (redevelopment projects) leads to a **driving scheme** voluntarily offensive since reflecting a maximum of projects even if not yet decided. Such a driving scheme is presented in Error! Reference source not found. with the two architectures prevailing from 2008 to 2011 and from 2012 to 2018.

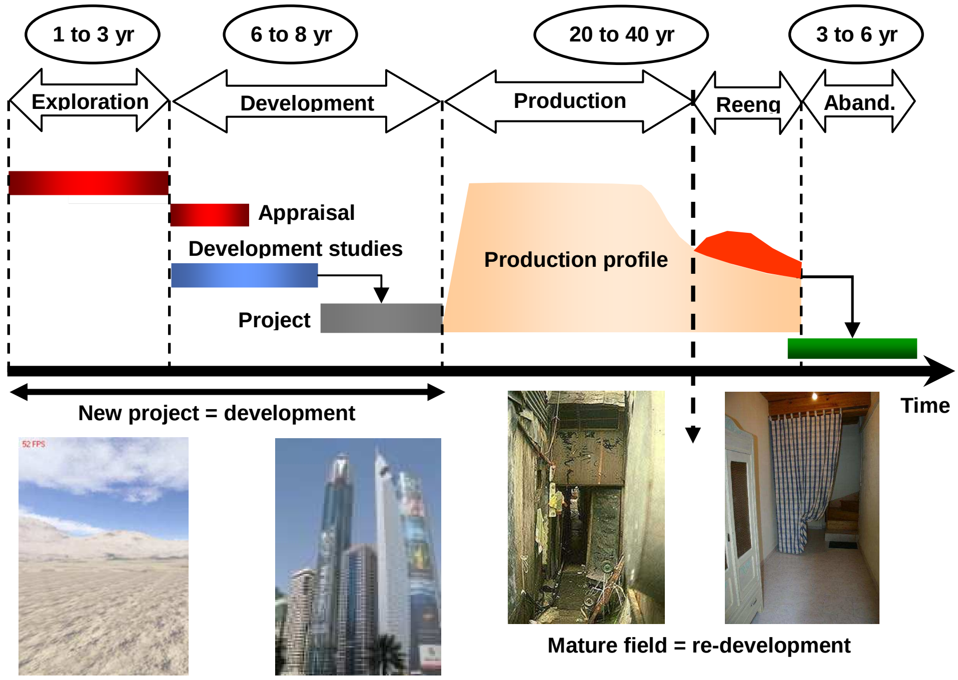

Figure 11 – Main difference between conventional projects
and Mature Field re-development

Conclusions

When developing a new field, architecture which includes all the development studies intervenes between end of appraisal and beginning of project phases. It implies most of conventional engineering disciplines (reservoir, drilling, process).
Re-development of a Mature Field will intervene after a more or long production period over which distribution of the fluids within the reservoir have been profoundly disturbed and existing facilities have suffered from more or less heavy deterioration. As shown in Figure 11, there is an interesting analogy between petroleum architecture and construction of buildings : a new development project will be quite similar to a new construction whereas the re-engineering of a mature field will be close to the restoration of an old building and will require to narrowly couple refurbishment and redevelopment.

Re-engineering of a Mature Field requires number of iterations between mitigation action and re-development plan making the driving scheme much more complex compared to that of a new project. Such exercises require extensive competences and experience as well as cross knowledge for each discipline to include/understand the importance of the constraints and the relevancy of the requests of the other. However, in most organizations, the Mature Field positions which appear "mechanically" devalued with respect to those associated with new large projects involving more reserves, higher production and larger investment do not attract the most qualified and experienced people. Finally and by contrast to new projects for which any technical innovation can be envisaged at an early stage, it is always very risky to envisage their implementation on degraded installations (challenging work over, degraded pumping units, lack of space on existing platforms, needs for additional power supply…). The degraded state of mature installations will first demand the rigorous application of the methodology detailed in this paper before envisaging the application of innovative technologies. It should not however be forgotten that in the future, these technologies and in particular those related to tertiary recovery (EOR) are impossible to circumvent since representing the only growth leverage to go further than 40% of oil recovery.

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