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DEVELOPMENT PLANNING: A SYSTEMATIC APPROACH

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ABSTRACT

A primary goal of an oil or gas field development is to maximize the present value of the investment. A systematically-prepared Plan of Development (POD) can assist operators in achieving this goal by ensuring that all factors are considered in evaluating, planning, and carrying out the field development.

A POD should contain an evaluation of all major events that realistically may occur during the field development cycle. By considering these events in the planning stage their probability of occurrence, effect on operations, and risk-weighted financial impact can be analyzed before field development begins. Depending upon the financial impact of the event, the field development strategy can be planned to alter the probability of occurrence or to reduce the consequences of the event.

The contents of a systematic plan of development are presented and discussed: Design Basis, Exploitation, Operations & Maintenance, Engineering, and Economics. Two Southeast Asian Field examples are used to illustrate how field economics would have been enhanced had a development plan been prepared using a systematic approach.

INTRODUCTION

Field development planning is not a new subject; from very early in the history of the oil industry the benefits of development planning were recognized.[1] However, with the uncertainty in crude prices, the advances in oil field technology and computing capability, and the smaller and poorer-quality reservoirs that are often discovered, the breadth and detail of planning today generally exceeds that conducted in the past. With the large investments often required today, it is necessary to examine all field development options in detail and to document the evaluation. This permits management, joint venture partners, and government regulatory bodies to follow the reasoning which resulted in the chosen development method.

A number of papers have addressed development planning. Behrenbruch[2] described offshore field development planning and stressed the need for flexibility and simplicity in design and that geologic modelling of the reservoir is essential to accurate reserve and productivity predictions. The concept of risk-weighting the net present value of the project was emphasized as necessary for proper decision analysis.

Buchanan and Hoogteyling[3] discussed the Auk Field, a marginal North Sea Field, and stressed that flexibility in facility design (mainly additional well slots) and continuous interaction between a variety of technical disciplines were keys to the economic success of a very complicated, marginal offshore development.

Thambydurai et. al.[4] summarized development planning for the Jerneh field offshore peninsular Malaysia. Their work highlighted the importance of detailed geologic and reservoir information to properly design and plan facilities requirements.

Egbogah et. al.[5] presented an approach to developing Dulang, a large oil and gas field offshore peninsular Malaysia. Flexibility, a multi-disciplinary team approach, and a staged development were highlighted as key characteristics of the development plan.

While these are excellent studies of individual projects and types of developments, the detailed contents of a Field Plan of Development were not presented. Reference 6 contains guidelines for POD content but does not address preparation methods and the internal requirements for a POD. Both preparation and contents are discussed in this paper.

References and illustrations are given at the end of the paper.

DISCUSSION

Development of an oil or gas field, after appraisal and screening studies have shown it to be viable, consists of three major phases. Each phase includes certain documentation for which an appropriate management response is required as follows:

Phase	Resulting Documentation
1. Exploration and Prospective Project	a. Project Initiation b. Feasibility study
2. Appraisal and Development	a. Plan of Development b. Design Basis Memorandum c. Project Execution Plan
3. Production	a. Project Stage, Completion, Cost, and Exception Reports b. Yearly Field Reviews

The POD is the initial step in the development phase and explains ***WHAT*** will be done, whereas in subsequent phases all technical design and project management aspects are developed in detail, resulting in a Project Execution Plan, which explains ***HOW*** it will be done.

The primary purpose of a POD is to serve as a project specification for the facilities and the operational philosophy required for new or supplementary production from a reservoir. It provides management with evidence that all aspects of the project have been identified, considered and discussed between the relevant parties. It also provides assurance of a structured, optimized plan with emphasis placed on basic data accuracy and full explanation of facility design and future operating requirements.

By analogy a systematic POD can be compared to the pilot's checklist prepared before, during, and after every flight. The number of aircraft accidents that could have been avoided with proper attention to the checklist is probably substantial. Likewise, the number of suboptimal developments that might have been avoided or corrected by application of a systematic POD is substantial. Two actual cases are presented in this paper. Caution must be exercised that a checklist-type approach does constrain creative solutions, however, in many oilfield operations a systematic approach generally results in much improved results.

Table 1 illustrates the initial stages of a typical oil field appraisal/development life cycle. This Table helps to illustrate an important characteristic of the POD, namely, that its scope and detail may be adapted for use in all stages of field appraisal and development. The basic POD outline can, for example, be used (1) as a preliminary screening study after field discovery but before delineation drilling, (2) after delineation drilling, incorporating the new data, as a feasibility study for management, (3) following management approval, as a submission to partners and to the appropriate Government authorities for field development approval and (4) with additional detail added, as an annual internal company review of the development and field operations compared to original plans.

PREPARATION

Preparation of a POD is an iterative process, in which concepts from various disciplines are combined into a general plan for evaluation. While one concept may be optimal from a reservoir management perspective, for example, when placed in the total scheme it could make project economics less favourable. To develop an optimal plan from all disciplines, an iterative process is required; it would be unlikely for individually optimized POD components from various disciplines to combine into an optimized overall POD.

The influence diagram in Figure 1 shows the key variables affecting a POD. To address these variables, a multi-disciplinary project team is usually needed including geologic and geophysical, engineering, operations, and management personnel. Often one person is appointed as a project leader to coordinate, schedule and steward plan preparation. A clear delineation and allocation of responsibilities among team members helps ensure the plan is prepared in an efficient and timely manner. Also needed is definition of approval and review timing and authority by management and nonparticipating experts. Periodic management review and approval of the interim status and results of the plan is essential.

Tables 2 through 6 outline the main Sections of a POD: Design Basis, Exploitation, Operations and Maintenance, Engineering, and Economics. An Executive Summary should also be included, but this will not be discussed here. Some Development Plans will contain a substantial amount of detail in each section, while others will contain only summary information. The contents of a particular POD will vary depending upon the type of development under considerations (e.g. new field development versus infill drilling) and the project stage being addressed by the POD (a screening study POD has less detail than a POD submitted for Government and partner approval).

DESIGN BASIS

This section summarizes the key planning parameters of the development and includes a clear description of the goals and objectives of the POD. The key parameters are used in the engineering section to develop detailed facilities and equipment requirements and specifications. A typical field development goal is:

> Development and depletion of a hydrocarbon resource with the minimum expenditure and environmental impact possible while also maximizing recovery, net present value, and safety.

Several critical components of the Design Basis section are described below, while a more detailed list of these components is contained in Table 2.

Reservoir and Fluid Characteristics. The reservoir and fluid characteristics should be summarized and the basic data used in preparing the POD illustrated. Unusual properties (rock compaction, retrograde condensation, etc) that significantly affect field development should be highlighted.

Production and Injection Forecasts. Final production and injection forecasts should be presented in graphical form, with high, medium and low cases presented, as appropriate.

Wells. The number and type of wells should be listed, including subsurface and surface equipment and operating requirements for those wells. The schedule of well and well equipment requirements should also be presented.

Engineering, Operating and Maintenance Philosophy. This 'position statement' describes the POD project team's philosophy concerning facilities design and operating characteristics, spending constraints (capital, operating, and maintenance), project timing, uncertainty in reservoir description and production forecasts, flexibility, abandonment, and safety and environmental concerns. An example of a typical operating philosophy statement is:

> To minimize staffing levels, the production facilities will be monitored and remotely controlled, to the maximum safe and practical extent, using supervisory control and data acquisition (SCADA) systems.

Installations. A summary of the number and location of facilities required to support the wells, separation, injection, water disposal, gas compression, and production utilities should be presented.

Transportation. The preferred option for transportation of crude and gas to market should be outlined. Parameters governing the design of this option (distance to market, volumes, required pressures, etc.) should be covered.

Infrastructure. Any infrastructure required, such as roads, buildings, runways/heliports, right-of-way clearances, that are not part of the installation section should be included here.

Government and Third Party Consent. Details of required Government and Third Party Consent, such as land rights or unitization, should be summarized. The timing and plan of approach to secure consent and Government approval for development should be reviewed.

Safety/Environment. Applicable regulations and standards should be outlined and a summary of major safety systems, environmental studies, and environmental response plans should be presented.

EXPLOITATION

The Exploitation section contains the subsurface plan for the development, and as a result is the most important part of a POD. This is because the in-place volumes, reserves, field deliverability, and reservoir management strategy drive the completion, facilities, and transportation schemes. The development strategy-scenario-forecast evaluation cycle[7] is based upon the Exploitation section data and results.

An example NPV sensitivity tornado chart in Figure 2 shows the overriding importance of the Exploitation section by the large sensitivity of the project net present value (NPV) to the reserve and initial rate estimates. Reasonable variation of other components results in much lower changes in NPV. Depending upon the project, the relative contributions of the various components may change, however, reserves, prices, and deliverability are frequently the most important variables affecting project NPV.

Unfortunately, the conclusions presented in the Exploitation section are typically the least reliable components of a POD because of the uncertainties in determining reserves and deliverability from a limited number of exploration/delineation wells. This being the case, it is prudent to spend a significant amount of time and effort in preparing the Exploitation section and ensuring that the resulting reserves and rate predictions are properly risk-weighted. If additional data are needed, recommendations should be made to obtain that data based on the value of the information.[7,8,9] These recommendations should emphasize the effects of not having the data on the project in a cost-benefit analysis format.

The importance of the Exploitation section highlights the need for the development planning process to begin during the prospect evaluation phase of an exploration program. The objective is to maximize the value of information obtained from each well and not wait until discovery before planning data requirements.

In summary, the exploitation portion of the POD contains information about reservoir characteristics, field reserves, deliverability and reservoir management options. The contents of the Exploitation section are outlined in Table 3, while some key elements are discussed below.

Geology and Geophysics. Basic data, maps and the final geologic and geophysical model of the reservoir and associated aquifer should be presented and discussed, along with comments about fault, fracture, and shale extent and transmissibility. The degree of uncertainty in the interpretation should be highlighted, and alternative scenarios presented along with the probabilities (of occurrence) assigned to those scenarios.

Data required and plans for periodic updates to the geologic model should be stated.

Hydrocarbons In Place. Volumetric estimates of oil, gas and condensate should be provided for each identified reservoir or zone with the field totals based on a geological model. The basis of the calculations should be given and their sensitivity to uncertainties in the input parameters highlighted. Calculations can be done on a probabilistic basis leading to expectation curves and/or low, medium, and high deterministic cases. If a deterministic method is used, the basis for each case should be presented.

Reserves. Estimates of recoverable reserves for each reservoir should be provided. As with the estimates of hydrocarbons in place, the range of recoverable reserve estimates should be provided with the probabilities that the Operator attaches to them. Reservoir simulation studies/reports that support the recovery estimates should be referenced. Results should be given for primary recovery and for alternative schemes of secondary and enhanced recovery. For gas-condensate reservoirs, the choice of depletion and separation method should be discussed.

Reservoir Management. The reservoir management plan should use the geologic model and incorporate data such as capillary pressure, relative permeability, etc to evaluate sensitivities to drive mechanism, pressure maintenance, artificial lift, well number, well completion (vertical, horizontal, or multiple laterals) and facility/well timing. Typically, depending on the point in a field's life cycle, reservoir management studies will follow a progression from analytic or single well models, to cross-sectional simulation models, and finally to full-field simulation models of the major reservoirs within the development.

Guidelines resulting from the reservoir management plan for production controls (offtake rate, GOR and watercut limitations) and measures to conserve reservoir energy and optimize ultimate recovery should be highlighted. The offtake guidelines and strategies should have realistic operational constraints. The guidelines should be documented, reasons for their selection presented, and alternative strategies commented upon.

Workover, well servicing, and zone completion plans, by well, area and field should be discussed, highlighting their timing and effect on rate and recovery.

Reservoir and Production Engineering. Plans for routine observations to monitor geological, petrophysical and reservoir characteristics in the development wells should be included. The program for downhole pressure surveys and other measurements to establish and monitor efficient depletion of the reservoir should be addressed.

Development Drilling. The proposed drainage pattern and drilling sequence for production wells, water injection and gas injection/recycling wells should be given. The degree of flexibility and contingency with respect to number of well slots or locations available and the timing of the drilling sequence should be discussed, showing the consequences for recovery and planned level of production. The scope for future unspecified drilling requirements, such as the high recovery case or enhanced recovery schemes, should be considered.

The program for completion intervals should be described and some indication of the completion and perforation philosophy given, especially in a layered sequence where separate layers may be treated as discrete reservoir units. Completion options that reduce costs originally and throughout field life should be sought.

Well Performance Prediction. The method of predicting well performance predictions should be presented, including a graphical illustration of vertical flow characteristics at various anticipated water cuts. This provides an indication of reservoir pressure levels at which the wells are likely to require artificial lift. Typically, nodal analysis is used for these predictions.

Production and Injection Profiles. Field life and production/injection rates should be given along with the range of uncertainties and the assumptions underlying the forecasts. The consequences of the high or low recovery cases applying should be considered.

The annual forecast production of oil, gas, associated gas liquids and water should be given for the anticipated life of the field in tabulated and graphical form. These should be broken down into contributions from each significant reservoir and layer. The extent to which the forecasts are dependent upon assumptions concerning well capacity, sequence of drilling, workovers, and well servicing should be stated. Maximum and minimum profiles showing the range of such uncertainty should be given and illustrated on a graph.

Injection fluid volumes should be given for the same period and in the same breakdown (reservoir or layer) as given for the production profiles.

Gas Production Profiles. Where gas is subject to a supply contract or is to be used for injection, the following information should be provided as a minimum: annual forecast of field daily contract quantity, field delivery capacity, fuel & flare consumption, timing and effect on field deliverability of adding or increasing compression, volumes of condensate or associated gas liquids, and heating values of the gas.

OPERATIONS AND MAINTENANCE

Organization, lines of authority, operating and maintenance needs, safety and emergency planning and provision are all important parts of this section. Another element of the operations and maintenance plans is their feedback loop to the exploitation plan - as data are gathered during the development's operational phase, the exploitation plan should be revisited to determine if changes are needed. The operations and maintenance activities that should be discussed in the POD are outlined in Table 4.

Organization. This section includes a description of the main organizational structure, reporting responsibilities, and lines of authority during the significant phases of the project following installation. The control of operations during the drilling period and production period should be highlighted with a clear delineation of lines of authority, particularly for an offshore location,. This can reduce problems that might occur during concurrent activities in the field.

Production Operations. This subsection includes all operational aspects of the wells, facility and transportation system, from the pre-commissioning to normal operating mode. Contents of this section should include:

a. Pre-commissioning, pre-start-up technical audits and timing, preparation of Operating and Maintenance manuals, certification by appropriate regulatory bodies, and safety inspection.

b. Oil or gas production start-up concurrent with development drilling.

c. Normal operation and supervision procedures.

d. Unmanned and/or remote control operation during production.

e. Safe working procedures, emergency plans and lines of control, environmental action and response plans, etc.

Maintenance Operations. Activities which should be considered in this subsection include regular schedules of maintenance and shutdowns, spare parts, breakdown and repair provisions, inspection requirements, work order and reporting systems, and work permit/safety systems.

Drilling, Completion, and Surveillance. The development drilling, future workover, and well servicing and surveillance plans should be presented and discussed. Schedules should be shown, and planning for and handling of concurrent activities discussed.

ENGINEERING

This section contains information about the detailed engineering used to design the production facility and transportation system. It should detail methods used, major assumptions, and alternatives investigated. In the early stages of a project, especially before management or government approval, detailed design engineering will not have been completed so project schedules for this work should be presented. An outline of the topics to be covered is given in Table 5.

Field Installation and Drilling Facilities. An overview of field installation and drilling facility characteristics and the schedules for engineering, procurement, construction, transportation, and installation should be presented.

Production Facilities. The design basis, methods used, arrangement, components, and scheduling of the production facilities should be discussed. The selection criteria for the process and arrangement of the facilities require description along with a discussion of alternative schemes evaluated. For example, the reasons to combine or separate compression modules from the process facility platform might be discussed, if applicable. Safety and environmental systems should be addressed.

Hydrocarbon Transportation Systems. The design basis and selected arrangement for flowlines, transfer pipelines, compressor stations, loading/unloading systems, and terminals should be presented. Alternatives considered and cost reduction options (smaller line sizes and use of friction/drag reducers, for example) should be highlighted for each of the major components in the system. Safety and environmental systems should also be presented.

Project Organization. The organization required to execute the development plan and subsequent operational phase should be outlined. This provides a blueprint for management on the method of proceeding with the development and operation following approval of the POD, and it allows project costs to be estimated.

ECONOMICS

The Economics section combines costs and price forecasts with output from the previous sections to allow management evaluation of project viability. An important part of this section is the risk analysis and associated sensitivity studies. Critical factors that will "make or break" the project must be identified, quantified, and their probabilities discussed. It is at this point that the value of information becomes apparent, and where additional information, although possibly very costly, may become economical from the overall project perspective.[10,11]

Table 6 is an outline of this section; some components are discussed below.

Capital Cost Estimates. The estimated capital expenditures should be given and shown by year and as cumulatives. A time schedule, showing both the costs and the items on a Gantt chart, is a good illustrative device to show critical path items for initial development.

Estimated capital expenditures by plant, facility or platform should be given, distinguishing as far as practicable between individual subsystems (oil, gas, water, etc.). For offshore facilities, the distribution of estimated costs over modules and decks should be given. Estimated capital expenditure for each structure should be presented, distinguishing between major components of both fixed (deck, substructure, piling, etc.) or floating (decks, hull, mooring, risers, etc.) structures, as appropriate.

Capital expenditures should be shown separately for flowlines, interfield/inter-platform pipelines, offshore loading system pipelines and feeder/link pipelines, distinguishing between liquid and gas pipelines. Capital expenditures for onshore and offshore trunk oil and gas pipelines should be shown. Costs for intermediate manifolds, risers and booster (pump/compressor) stations should be included. Costs of pig launchers/receivers, manifolds and slugcatchers should be included.

Estimated capital expenditures on terminals should be outlined, distinguishing between crude stabilization, gas processing, storage, effluent treatment, water treatment, pumping, tanker loading, metering equipment, safety/firefighting, power and water supply, site acquisition and preparation, civil engineering work, offices, etc.

Estimated capital expenditure for central base facilities (staff housing, recreational facilities, offices, workshops, yards) and infrastructure such as roads, wharfs, jetties, etc. should be given.

Construction, transportation, insurance, and importation costs should be presented, where significant, for the components to which they apply.

Costs arising from terminating production, well abandonment according to reasonably anticipated regulatory abandonment guidelines, and removal of equipment at the end of field life should be given. The anticipated realization of assets disposed of or their value on transfer to other projects, e.g. compressors, separators, gensets, floating production equipment, should be considered. These costs should be given for the years in which they are expected to occur, in as much detail as appropriate.

Operating Cost Estimates. Operating cost estimates should include itemized listings of:

a. The cost of materials, supplies, fuel, catering costs and contracted services attributable to production, treatment and transportation or disposal of oil, gas or water.

b. Maintenance costs of plants, equipment, sites, platforms, offshore loading systems, other offshore structures and field/feeder pipelines, including materials, replacement parts and contracted services for inspection, maintenance and repair, distinguishing for offshore between topside and subsea work (excluding well maintenance).

c. Well maintenance costs including wellhead equipment and flowline repairs and maintenance, workovers and downhole activities.

d. Transport costs for personnel, supplies, materials,equipment and replacement parts by land, air or sea to the field and between sites, plants and platforms.

e. For offshore operations: the cost of standby/emergency vessels or helicopters or the field's share of the cost of any such mutual support arrangements in the area.

f. Any other operating expenditures that are not allocated to the appropriate function, including head office operating expenditures, or financial charges for provision of working capital for all the cost areas described above, should be specified if they are of a significant magnitude.

A brief explanation should be given of the provision that has been made by the operating company and the partners to meet civil liability claims for pollution damage arising from any oil spills occurring during the life of the field.

Revenues. In this subsection the price scenarios for oil and gas are detailed and combined with the production profiles developed in the Exploitation section to generate the gross revenue stream. A risked distribution of possible price scenarios should be presented and discussed, with details of the distribution chosen to summarize project economics.

Overall Economics. This subsection contains the economic yardsticks that most managements use to evaluate projects, including net present value, internal rate of return, maximum negative cash flow, payout, investment efficiency, etc.

FIELD EXAMPLES

Two examples are presented illustrating the benefits of proper development planning. They serve to illustrate that if the development plan is not prepared in a systematic way, project economics can be seriously affected. These are actual case histories although the field names and other information have not been included for confidentiality reasons.

Example 1

This field, located in a deep water, remote location in Southeast Asia, is in a high permeability Miocene Reef formation. The formation is fractured and exhibits high productivity indices following stimulation. Offset fields have exhibited strong bottom-water drive, with the oil production rate rapidly diminishing when water encroached into the wellbore. The high-permeability fractures and low-permeability matrix were conducive to early hydrocarbon depletion from the fractures with subsequent water entry from an underlying aquifer.

In spite of offset field experience, the operator made no provision for artificial lift or for shutting-off bottom-water. As a result, one of the wells loaded-up and died at about 80% water cut after producing for less than one year. At the time it died the well was still producing over 1,000 BOPD. Rough estimates indicate that high volume artificial lift would have increased oil production to over 2500 BOPD (while handling increasing amounts of water) and resulted in sustained oil rates at high water cuts.

After additional wells watered-out and several workovers were conducted to sidetrack the original completions, the field is currently (August, 1994) producing at about 25% of the original forecast rate. Even during the workovers, when the provision for artificial lift could have been made relatively cheaply, no artificial lift was installed. Other alternatives, such as multiple laterals which might have intersected non-watered-out fracture systems, were not seriously considered.

In this instance the operator failed on at least two counts: a proper Exploitation study was not conducted, and management was not committed to an optimum development. The reasons for these failures are unknown, although the operator maintained a minimal staff and upper management were not accustomed to 'high technology' applications. Whatever the reasons for the failures, the lesson is the same: to optimize a development proper planning is required and those plans must be implemented.

Example 2

This small onshore oil and gas-condensate field is in a Miocene carbonate formation with relatively low permeability and porosity. Logs and initial DSTs indicated the reservoir contained an oil rim that was overlaid by a gas cap and underlain by water. During short term production tests two wells had oil rates of up to 2,000 BOPD and gas rates of 4 MMSCF/D from each well. The gas rates (and GOR) were increasing at the conclusion of each test and were substantially greater than the solution GOR. Based on these 6-hour tests, several additional wells were drilled to maximize the oil production rate. No additional testing was conducted on the original two wells.

The additional wells encountered a retrograde gas cap instead of a producible oil rim. Despite the apparent large gas cap, normal temperature separation facilities were designed and installed to handle over 6,000 BOPD. Furthermore, no provision was made to re-inject or market the produced gas.

Unfortunately, shortly after production began gas-oil ratios increased dramatically in the two oil wells. The maximum oil rate from the field after production began was 2,300 BOPD and it has continued to decrease since that time. The thin oil rim was essentially bypassed by water from below and, at structure top, by gas from above. The field was produced during the next eighteen months, condensate stripped using normal temperature separation, and gas flared while a gas contract was negotiated and a gas sales line installed. During that period over 10 BCF of gas were flared; relatively low-cost low-temperature separation equipment would have yielded an additional 300,000 STB of condensate from the flared gas.

Had the operator systematically evaluated the uncertainties in the exploitation plan for the reservoir, the possibility of high GOR production could have been evaluated and expected production rates determined on a risk-weighted basis. Based on this analysis, facilities to optimize liquids recovery might have been installed and, more importantly, a gas contract and marketing arrangement negotiated. Furthermore, since the field was onshore the operator could have easily conducted a long term test of the oil wells and would have found that the gas-oil ratio increased dramatically. There was evidence from offset fields that high initial oil rates in the producing formation declined significantly, and this also should have been considered in the plan of development.

It should be noted that, in this case, several of the uncertainties were identified for management but were not acted upon. For planning to result in a successful outcome, management must be amenable to changes and data requirements identified in the development planning stage.

CONCLUDING REMARKS

Throughout the text the POD was presented and discussed in a sequential manner, however, this is not the optimum method of preparation. Indeed, the order presented herein is generally not the same as the order of work. Typically, the Exploitation section is prepared for various scenarios and the Design Basis, Engineering, Operations/Maintenance and Economics sections are combined in a strategy-scenario-forecast iterative loop until an optimal development strategy is identified. Often a parallel approach by a multi-faceted team is the most efficient method of conducting the work. During the process, there should be many feedback loops so that the development plan evolves towards the best available option and effort spent on uneconomical options is minimized.

Questions that should be asked throughout the process include:

1. What are the alternatives?
2. Are the data reliable and are additional data required?
3. What flexibility do we have in the plan, and how much are we spending for this flexibility?
4. What components should be emphasized, and which should be de-emphasized (as determined by their impact on project economics)?

With the proper attention to detail and periodic management and outside review/acceptance, a POD can ensure that the project is developed optimally, as far as the accuracy of the geology and engineering data will allow.

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TABLE 1. APPRAISAL/DEVELOPMENT CYCLE

LEVEL	1	2	3	4	5
PHASE	SCREENING	FEASIBILITY	DEFINITION	CONCEPTUAL DESIGN	DETAILED DESIGN
STARTING POINT	•Discovery confirmed •Exploration 2D seismic map •Exploration well test data	•Appraisal completed •Data acquisition (Level 1) completed	•Proved HIP >50% expected value •Economic screening •Sufficient data to firm up base case	•Development plan agreed	•Finally refined technical and contractual data
DATA ACCURACY	•Parameters for estimating reserves/prod. profiles -50% to +100% •Capex ±40%	•Parameters for estimating reserves/prod. profiles ±30% •Capex ±25%	•Well numbers ±20% •Parameters for estimating reserves/prod, profiles ±25% •Design capacities ±10% •Capex ±15%	•Well numbers ±10% •Parameters for estimating reserves and prod, profiles ±20% •Capex ±10%	•Parameters for estimating reserves/prod. profiles ±20% •Capex ±10%
THIRD PARTY & COMMERCIAL ACTIVITIES (during phase)	•Consider potential 3rd party involvement •Consider transportation routes for gas: earliest date, indicative prices, tariffs, strategic opportunities, etc. •Preliminary economic screening	•Assess strengths & weaknesses of principal participants •Formulate negotiating strategies •Identify potential gas sales package •Identify transport & processing infrastructure •Economic evaluation of base case and options.	•Agree major JOA issues e.g. operatorship, cost sharing, equity principles •Draft transportation & processing letter agreements •Draft gas sales contracts •Economic analysis to support Strategic Plan and Budgets	•Agree commercial issues in JOA,etc, in such detail as needed for Management and Government approval. •Profitability analysis to support Strategic Plan and Budgets	•Finalise commercial agreements
RESULTING DOCUMENTATION	•Screening study •Agreed table of uncertainties & additional data requirements	•Feasibility study. •Commercial strategy	•Plan of Development for internal/partner approval and for submission to Government Authorities •Transportation and Processing Agreements •Budget for next phase	•Government commerciality approval •Design Basis Memorandum •Agreed drafts of full commercial agreements •Budget for next phase	•Detailed specs for contracts/purchase orders •Finalised transportation processing/sales contracts

TABLE 2
DESIGN BASIS SECTION - MAJOR COMPONENTS

1.0 FIELD LOCATION

1.1 RESERVOIR AND FLUID CHARACTERISTICS

1.2 PRODUCTION AND INJECTION FORECASTS

- 1.2.1 Reservoir Management Objectives and Plans
- 1.2.2 Production and Injection Rates
- 1.2.3 Reservoirs to Be Developed
- 1.2.4 Sequence of Reservoir Development

1.3 WELLS

- 1.3.1 Production (subsea or platform, singles or duals)
- 1.3.2 Gas Injection
- 1.3.3 Water Injection
- 1.3.4 Delineation or Infill Production Wells Required
- 1.3.5 Well Completion/Equipment Outline
- 1.3.6 Timing of Wells

1.4 ENGINEERING, OPERATING & MAINTENANCE PHILOSOPHY

1.5 INSTALLATIONS

- 1.5.1 Wells (prod/gi/wi/other)
- 1.5.2 Locations of Wells (onshore, per platform or subsea) and overall Design Rates
- 1.5.3 Wellhead/Flowline Details
- 1.5.4 Oil/Gas/Water Separation and Stabilization Facilities
- 1.5.5 Water Injection/Disposal Facilities
- 1.5.6 Gas Compression Facilities
- 1.5.7 Gas Reinjection Facilities
- 1.5.8 Gas Flaring Facilities
- 1.5.9 Natural Gas Liquids Recovery Facilities
- 1.5.10 Power Generation Facilities

1.6 HYDROCARBON TRANSPORTATION SYSTEM

1.7 INFRASTRUCTURE

1.9 GOVERNMENT AND THIRD PARTY CONSENT

1.10 SAFETY/ENVIRONMENT

TABLE 3
EXPLOITATION SECTION - MAJOR COMPONENTS

2.0 HISTORY AND STATUS

- 2.0.1 Discovery and Appraisal
- 2.0.2 Licenses and Operators Involved
- 2.0.3 Offset Operators and Local Infrastructure
- 2.0.4 Offset and Look-Alike Field Comparison

2.1 GEOLOGY AND GEOPHYSICS

- 2.1.1 Seismic Data
- 2.1.2 Structural Interpretation
- 2.1.3 Stratigraphic and Offset Well Data
- 2.1.4 Reservoir Description of the Field
- 2.1.5 Maps and Diagrams

2.2 PETROPHYSICAL AND RESERVOIR FLUID PARAMETERS

- 2.2.1 Petrophysical Interpretation
- 2.2.2 Routine Core Analysis at Atmospheric and Overburden P/T
- 2.2.3 Special Core Analysis - Cap Pressure, Rel. Perm, Rock Compaction
- 2.2.4 PVT Analysis
- 2.2.5 Reservoir Fluid Properties

2.3 RESERVES

- 2.3.1 Hydrocarbons in Place
- 2.3.2 Hydrocarbon Recovery Plan

2.4 RESERVOIR MANAGEMENT

- 2.4.1 Geologic and Engineering Models of Reservoir
- 2.4.2 Drive Mechanism and Reservoir Continuity
- 2.4.3 Well and Field Deliverability
- 2.4.4 Well Spacing and Completion Strategy
- 2.4.5 Reservoir Development Plan
- 2.4.6 Development Drilling Plan - Timing and Location
- 2.4.7 Pressure Maintenance Scheme
- 2.4.8 Artificial Lift
- 2.4.9 Improved Recovery
- 2.4.10 Performance Monitoring

2.5 FIELD LIFE AND PRODUCTION PROFILES

- 2.5.1 Field Life
- 2.5.2 Production Profiles
- 2.5.3 Injection Profiles
- 2.5.4 Gas Production Profiles

2.6 PRODUCTION & FACILITIES ENGINEERING OVERVIEW

- 2.6.1 Well Completions - Equipment, Metallurgy, Strategy
- 2.6.2 Wellheads and Flowlines
- 2.6.3 Production Facilities
- 2.6.4 Transportation System

TABLE 4
OPERATING & MAINTENANCE SECTION - MAJOR COMPONENTS

3.0 OPERATIONS PHILOSOPHY

- 3.0.1 General Overview of Planning Basis - Fluid Rates, Pressures, Controls
- 3.0.2 Facility and Well Operations

3.1 ORGANIZATION

3.2 PRODUCTION OPERATIONS

- 3.2.1 General Description of Production Operations Phases
- 3.2.2 Process and Utility Control Systems
- 3.2.3 Start-up and Shut-down Procedures
- 3.2.4 Major Production Operations
- 3.2.5 Interfaces with Other Installations
- 3.2.6 Testing and Metering
- 3.2.7 Pipelines Operations
- 3.2.8 Supervisory Control and Data Acquisition Systems
- 3.2.9 Corrosion Control and Monitoring
- 3.2.10 Other Aspects

3.3 MAINTENANCE OPERATIONS

- 3.3.1 General Overview on Uptime Policy and Maintenance Plans
- 3.3.2 Scheduling of Maintenance
- 3.3.3 Breakdown and Repair Provisions
- 3.3.4 Permits and Safety Systems
- 3.3.5 Inspection Requirements - Statutory/Company

3.4 DRILLING, COMPLETION AND SURVEILLANCE PLANS

- 3.4.1 General Description of Plans
- 3.4.2 Rig Type and Mobilization Details
- 3.4.3 Surface Drilling Facilities and Equipment
- 3.4.4 Mud, Casing, and Well Evaluation Program
- 3.4.5 Completion Techniques and Equipment
- 3.4.6 Drilling and Completion Costs and Timing
- 3.4.7 Reservoir and Well Surveillance Activities
- 3.4.8 Well Stimulation and Servicing

3.5 SUPPLY AND TRANSPORT OPERATIONS

- 3.5.1 General - Supply Points, Demand Rates, Pricing
- 3.5.2 Air/Marine/Land Transport Equipment and Procedures
- 3.5.3 Drilling and Production Supply Logistics

3.6 SAFETY AND ENVIRONMENTAL

- 3.6.1 Safety Philosophy and Reference to Safety Manual
- 3.6.2 Environmental Philosophy and Studies

TABLE 5
ENGINEERING SECTION - MAJOR COMPONENTS

4.0 FIELD INSTALLATION

- 4.0.1 Onshore Civil Works - Camps, Roads, Flowlines, etc.
- 4.0.2 Offshore Substructures
- 4.0.3 Certification and Insurance
- 4.0.4 Overall Quality Control and Quality Assurance

4.1 DRILLING FACILITIES

- 4.1.1 Locations
- 4.4.2 Access Roads and Bridges

4.2 PRODUCTION FACILITIES

- 4.2.1 General Arrangement
- 4.2.2 Process Facilities
- 4.2.3 Gas Utilization and Compression
- 4.2.4 Metering
- 4.2.5 Artificial Lift Facilities
- 4.2.6 Injection Plant
- 4.2.7 Water Disposal
- 4.2.8 Utilities, Telecommunications and Field Accommodation
- 4.2.9 Pollution Prevention and Control
- 4.2.10 Fire Suppression System
- 4.2.10 Safety and Evacuation Facilities and Plans
- 4.2.11 Emergency Shut-Down Systems
- 4.2.12 Electrical Systems
- 4.2.13 Compressed Air System
- 4.2.14 Corrosion Monitoring and Control
- 4.2.15 Environmental Monitoring Plan

4.3 HYDROCARBON TRANSPORTATION SYSTEMS

- 4.3.1 Pipelines and Flowlines
- 4.3.2 Pipeline Pumping and Compressor Stations
- 4.3.3 Shore Terminals - Location, Ownership and Layout
- 4.3.4 Pipeline Manifold
- 4.3.5 Terminal Process and Utility Systems
- 4.3.6 Storage
- 4.3.7 Terminal Marine, Road and Rail Loading
- 4.3.8 Terminal Effluent Treatment
- 4.3.9 Safety Facilities
- 4.3.10 Offshore Storage and Loading
- 4.3.11 Corrosion Monitoring and Control
- 4.3.12 Pollution Prevention and Control Measures

4.4 PROJECT ORGANIZATION

- 4.4.1 Project Planning and Time Estimates
- 4.4.2 Organization, Resources and Relationships
- 4.4.3 Contracting and Procurement
- 4.4.4 Quality Control and Assurance
- 4.4.5 Cost Control and Reporting
- 4.4.6 Design Changes and Consultation with 3rd Parties
- 4.4.9 Abandonment

TABLE 6
ECONOMICS SECTION - MAIN COMPONENTS

5.0 CAPITAL COST ESTIMATE

- 5.0.1 Presentation of Capital Expenditures Data
- 5.0.2 Allowances and Contingencies
- 5.0.3 Shared Facilities
- 5.0.4 Preliminary Development Costs
- 5.0.5 Appraisal Drilling and Seismic Costs
- 5.0.6 Development Drilling Costs
- 5.0.7 Production Facilities
- 5.0.8 Offshore Fixed Floating Substructures
- 5.0.9 Field Pipelines
- 5.0.10 Trunk Pipelines
- 5.0.11 Subsea Facilities
- 5.0.12 Storage/Loading Terminals
- 5.0.13 Offshore Loading Facilities
- 5.0.14 Ships and Mobile Floating Equipment
- 5.0.15 Capitalised Pre-Operating Costs
- 5.0.16 Other Capital Expenditure
- 5.0.17 Abandonment Costs
- 5.0.18 Cost of Further Development Studies
- 5.0.19 Insurance and Certification

5.1 OPERATING COST ESTIMATES

- 5.1.1 Wages and Salaries - Employees and Subcontractors
- 5.1.2 Production Operations
- 5.1.3 Maintenance of Plant, Platforms, Field Pipelines and Ancillary Facilities
- 5.1.4 Well Maintenance
- 5.1.5 Logistics
- 5.1.6 Safety and Environment
- 5.1.7 Charter Cost of (floating) Production/Storage Facilities
- 5.1.8 Tanker/Road/Rail Freight
- 5.1.9 Trunk Pipeline Operating Costs
- 5.1.10 Insurance and Certification
- 5.1.11 Terminal Operational Expenditures
- 5.1.12 Other Operating Expenditures - Home office Overhead Allocation, etc
- 5.1.13 Pollution Liability Provision

5.2 REVENUES

- 5.2.1 Price Assumptions for Oil and Gas
- 5.2.2 Production Profile
- 5.2.3 Gross and Net Revenue Stream

5.3 OVERALL ECONOMICS

- 5.3.1 Gross and Net Cash Flow to Contractors
- 5.3.2 Net Present Value and Internal Rate of Return
- 5.3.3 Other Economic Yardsticks (Payout, P/I, etc.)

Figure 1. Influence Diagram for Field Development

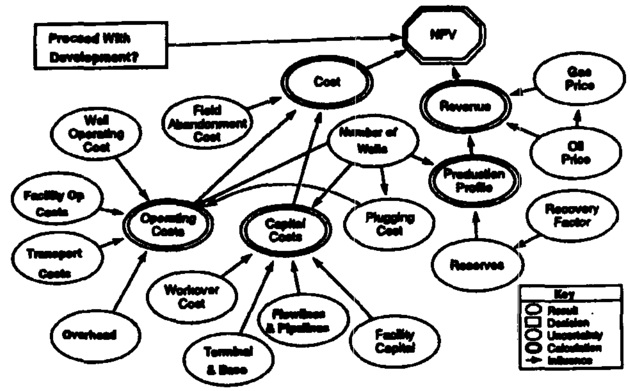

FIGURE 2. TYPICAL NPV SENSITIVITY