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# Lifecycle Cost of Deepwater Production Systems

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## Abstract

Many cost components must be considered to determine the most cost effective deepwater production system for a particular site. Too often, only the well systems CAPEX[1] is adequately included in field development alternative studies. OPEX, RAMEX and RISKEX depend largely on reservoir characteristics, specific well system designs and operating procedures. The effect of these factors nearly always outweigh differences in well system CAPEX. Optimization of total lifecycle cost of deepwater production systems must include all of these factors.

The risks associated with blowouts are often an important factor in choosing one dry tree tieback well system over another. Another important factor often overlooked is the cost of well system component failures. As oil exploration and production moves into deeper and deeper water, the costs to repair well system component failures escalate dramatically.

This paper presents the methodology developed by a Joint Industry Project to quantify capital, operational, blowout risk and reliability costs associated with deepwater well systems. Five well systems have been modeled to demonstrate the methodology: a dual casing dry tree system, a single casing dry tree system, a tubing riser dry tree system, a conventional tree subsea system and a horizontal tree subsea system. Case examples demonstrate the model for these five well systems.

The methodology, results and main conclusions from this Joint Industry Project are presented.

## Introduction

This paper summarizes the work of a Joint Industry Project (JIP) sponsored by five oil companies and the US Minerals Management Service (MMS) to estimate deepwater field development lifecycle CAPEX, OPEX, RISKEX, RAMEX, for subsea systems[1]. An earlier JIP, The Dry Tree Tieback Study (DTTAS) /1-4/, developed and demonstrated the methodology to calculate CAPEX, OPEX and RISKEX for alternative dry tree tieback systems.

That study demonstrated the importance of site-specific estimates of RISKEX, the probability of a blowout during field life multiplied by cost of a blowout, when deciding between single casing and dual casing riser systems.

In 1999 this JIP was initiated which broadened the scope of previous work to include conventional and horizontal tree subsea well systems in addition to Spar and TLP dry tree well systems. Most significantly, RAMEX for both dry tree tiebacks and subsea systems is included in this study. The methodology is especially useful for comparing alternative field development scenarios.

The spreadsheet tool that was developed in the DTTAS JIP has been expanded. The tool now expedites calculation of CAPEX, OPEX, RISKEX and RAMEX. The multiple spreadsheet format permits simple screening of alternative field development scenarios using built-in default values. In addition, detailed site-specific evaluations are possible by easily changing tabulated values for any data for which values that are more accurate are known.

Numerous case examples have been evaluated for a variety of field development scenarios. These studies have taught that a thorough site-specific evaluation is required to determine the most economical well system. The well system CAPEX, OPEX, RISKEX and RAMEX must be based on a thorough evaluation of reservoir characteristics. Too often, project personnel who select field development alternatives fail to consider adequately the lifecycle implication of their selections.

This work demonstrates the importance of site-specific evaluations that tailor the field development scenario to the unique reservoir characteristics. An effective reservoir-centered development requires thoughtful selection of a well system to acheive total lifecycle operational requirements. Lifecycle operational requirements usually involve significant well intervention activities.

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[1] Definitions of terms and acronyms are listed at the end of the paper.

Some wells do not produce as expected and must be kahP cb r                                               -complete to new zones because high production rates of these wells result in relatively fast zone depletion. Most reservoirs are layered and faulted. Most wells water-out and/or production rates drop to uneconomical levels in a relatively short time. For each zone, initial production rates, rate of production decline and total recoverable reservoirs must be considered in a difprot stogitap slPX lifecycle evaluation to ensure that future operational requirements are not overlooked in the original planning.

Some well system component failures should be anticipated for all wells. Tubing string leaks and sand control failures are inevitable and stimulation operations may be required to maintain acceptable production rates. Subse'otapdci tsi retab ri ves ntfip wells must also contend with subsea facilities failures in control system components, flying leads, manifold and tree valves, flowlines, etc. However, we find subsea system failures are less severe than sand control failures idnidpot s ta rei khi tqd star stimulation needs that are common to both dry tree and subsea wells.

Well system alternatives (dry trees, wet trees, dual casing risers, single casing risers, etc.) should be considered as apklot 's bt' ri rq phldei f

A detailed site-specific evaluation is required to determine the at of 'shitp                                  eld development.

Dry tree well systems become more vulnerable to loss of well control with increased water depth (riser length and stresses). Larger and more expensive platforms are required to support the larger risers.

Subsea well system repairs and interventions become more expensive and are associated with longer delays due to reduced availability and increased mobilization times for the required repair vessels.

**Cost Model.** The implications of disasters and business interruptions should be incorporated into business decision analyses that seek to evaluate the viability of alternative designs. Inclusion of these "unforeseen" RISKEX and RAMEX elements with the usual CAPEX and OPEX elements results in the economic model:

*Profit = Max (Revenue-CAPEX-OPEX–RISKEX-RAMEX)*

The methodology is developed to permit predictions of lifecycle cost for a field development based on statistical and judgmental reliability data and carefully estimated system parameters.

Some of the most difficult cost elements to calculate can be quickly and easily estimated with this methodology. Other costs must be included (platform and facilities cost, drilling costs, field operating costs) for a complete evaluation.

**Cost Elements Included.** The following cost elements are considered for both dry tree and subsea systems:

- CAPEX includes capital costs of materials and installation of the wells and systems. Materials include dry tree risers with associated equipment yac ria TRf snist sls

ds'fi                       surface trees, subsea systems such as subsea trees, pipelines, pipeline end manifolds, jumpers, umbilicals and controls systems. Installation costs includes vessel spread cost multiplied by the estimated installation time and rental or purchase cost for installation tools and equipment.

zonal recompletions. OPEX for these planned recompletions is intervention rig spread cost multiplied by the estimated recompletion time for each zonal recompletion. The number and timing of planned recompletions are uniquely dependent on the field development plan. This study has developed a methodology and spreadsheet tool that permits the user to use individual well reserves, initial production recompletion schedule and to develop a total field production profile.

- RISKEX is risk costs associated with loss of well control (blowouts) during installation, normal production operations and during recompletions. Risk cost is calculated as the probability of uncontrolled leaks multiplied by assumed consequences of the uncontrolled leaks.
- RAMEX is reliability-availability-maintainability costs associated with well or system component determined.

**Cost Elements Excluded.** Cost elements that are not included in this study are:

- Spar or TLP platform facilities materials and installation costs (platform, processing facilities, export risers and pipelines, drilling/workover rig capital cost, etc.).
- Drilling costs.
- Downhole completion equipment costs (packer, tubing, SCSSV, etc.).
- Field operations costs such as platform maintenance, downhole treatment chemicals, production operations personnel and boats and helicopters.

These cost elements must not be ignored for a thorough evaluation of field development alternatives. However, the cost elements that are estimated by the methodology described in this paper are often the most difficult to define and are critical in selecting the most economical well system alternatives.

## Methodology

The lifetime cost assessment methodology consists of the following steps:

1. Define field development plan.
2. Define well system components.

3. Develop an FMEA for the systems to identify leak paths and other potential component failures.
4. Develop step by step procedures for well intervention operations.
5. Calculate CAPEX.
6. Calculate lifecycle OPEX.
7. Calculate lifecycle RISKEX.
8. Calculate lifecycle RAMEX.
9. Calculate overall lifecycle cost (CAPEX, OPEX, RISKEX, and RAMEX).

**Define field development plan.** A realistic field description is the first and most important estimate that must be made. Data are always limited at this planning stage a project. There is often a tendency to design the development plan based on what is most likely. The following information must be estimated with as much accuracy as possible:

- Reservoir characteristics - size, shape, productive zones, fault blocks, water/gas drives, etc. that determine the number and location of wells.
- For each well - depth, formation pressure, recoverable reserves, design production rate, production profile and specific completion requirements such as type of sand control system.

In active oil provinces, it is important to consider existing infrastructure such as existing facilities to receive and process production from the wells.

**Define well system components.** It is necessary to define the components that comprise the well system. These components will form the basis of the RAMEX methodology and the leak paths used in the RISKEX calculations.

Typical downhole completion systems and dry tree tieback riser systems were developed in the previous studies. Additional base case designs of both conventional and horizontal tree subsea systems were developed in this study. These detailed designs permitted the identification of all well-control barriers and component seals for these typical systems.

**Identify potential component failures with a FMEA.** A Failure Modes and Effects Analysis, FMEA, is required to identify and document the failures and potential consequences for the well tieback system. This FMEA provides the basis for developing fault trees to calculate RISKEX and RAMEX.

**Develop step by step intervention procedures.** Operating procedures are required for initial installation of completion systems, planned workovers to new intervals as zones deplete, and unplanned interventions to repair and/or replace failed components. Initial completion procedures are used to calculate capital costs, CAPEX. Cost of planned interventions, i.e., recompletions as zones deplete, is OPEX. Cost to repair well system component failures is a major component of RAMEX. Individual steps of all operating procedures define changes in the well control barriers that provide the basis for risk costs, RISKEX.

The following procedures were developed for each dry tree

tieback alternative and subsea well system:

1. Initial Installation of Frac-pack Completion
2. Initial Installation of Horizontal Lateral Completion
3. Pull completion, Install New Frac-Pack Completion
4. Pull completion, Plug Lower Zone and Install Uphole Frac-Pack Completion
5. Pull completion, Plug Lower Zone, Sidetrack and Re-complete with Frac-Pack
6. Pull completion, Plug Lower Zone, Sidetrack and Re-complete Horizontal Well
7. Repair Completion System Leaks (pull and rerun completion string)
8. Repair/replace surface or subsea tree
9. Coil tubing downhole repair

The following procedures were developed for subsea equipment repairs/replacements:

1. Repair pipeline or PLEM
2. Repair/replace flowline jumper
3. Repair/replace tree jumper
4. Repair/replace hydraulic system umbilical
5. Repair/replace electrical system umbilical
6. Repair/replace well jumper
7. Repair/replace well flying leads
8. Repair/replace well control pod
9. Repair/replace well subsea choke
10. Repair extension pipeline or PLEM
11. Repair/replace extension jumper
12. Repair/replace hydraulic extension umbilical
13. Repair/replace electrical extension umbilical
14. Repair/replace tree jumper extension

These procedures provide a broad cross section of the types of work completed during the total field lifecycle. They can be tailored easily to describe the operations for other well depths and water depths.

**Calculate CAPEX.** CAPEX is calculated as the sum of well system materials and installation costs. The CAPEX for dry tree tieback alternatives includes riser related component costs such as riser joints, tensioners (including riser load cost penalty based on riser tension load), air can buoyancy modules and wellheads. The riser load cost penalty was larger for TLPs than for Spars because most Spar riser loads were supported by air cans.

The dry tree alternatives materials costs include riser-related costs for TLP or Spar and for dual casing risers, single casing risers and tubing riser materials. The data are formulated to permit cost estimates for various numbers of wells and various water depths.

CAPEX for the subsea well system includes pipelines between the subsea wells and host facility, pipeline end manifolds, subsea production manifolds, jumpers to connect the pipeline and manifold, hydraulic and electrical umbilicals, well jumpers, and conventional subsea trees or horizontal subsea trees. These basic CAPEX cost components for subsea systems can be used to tailor a site-specific CAPEX estimate.

CAPEX also includes installation costs that are calculated from defined vessel(s) spread costs multiplied by the vessel(s) operating time for initial well interventions and initial subsea system installations.

**Calculate lifecycle OPEX.** Each of the identified intervention procedures is broken into steps. The duration of each step is estimated from historical data. The non-discounted OPEX associated with a re-completion is estimated as:

$$OPEX = (Intervention\ Duration) \times (Rig\ Spread\ Cost)$$

OPEX values are tabulated in the appropriated year that the expense occurs to permit net present value, NPV, calculations.

**Calculate lifecycle RISKEX.** The RISKEX methodology developed in DTTAS /3/ was used as a basis for determining the RISKEX for the subsea completions.

The probability of failure of the well completion system is a function of the probability of failure during the various operating modes (drilling, initial completion, normal production, workovers and re-completions). The lifetime probability of a blowout is calculated as

$$P(BO\ during\ lifetime) = P(drilling) + P(initial\ completion)$$
$$P(prod) + \sum P(WO) + \sum P(re\text{-}compl.)$$

The cost of a blowout depends on the size of the release associated with a certain activity (j) is calculated as:

$$RC(j) = \sum_{i \in \{limited,\ major, extreme\}} Prob_i\ (activity\ j) \cdot C_i$$

where: $Prob_i$ (activity j) is the probability of a blowout of size i during activity j, and $C_i$ is the cost of leak of size, $i \in$ {limited, major, extreme}.

**Calculate lifecycle RAMEX costs.** Well components can fail that will require the well (and sometimes the entire system) to be shut-in while the component is being repaired. The costs to the operating company of these component failures are twofold:

- The cost to repair the component (i.e. repair vessel spread cost multiplied by duration), and

    • The lost production associated with one or more wells being down.

The average cost per year associated with these unforeseen repairs is called reliability, availability, and maintainability expenditures, or RAMEX. The RAMEX of a particular component is calculated by multiplying the probability of a failure of the component by the average consequence cost associated with the failure (repair and lost production costs). The system RAMEX is calculated by summing all of the component RAMEXs that are included in the particular system.

The RAMEX calculation is performed through the following four steps:

*1 - Identify components failures modes.* A table of well system components – from the reservoir to the tubing hanger - is developed for each completion system. Failure modes such as a sand control system failure, tubing leak and SCSSV failure are determined.

Subsea completion equipment (i.e., manifolds, jumpers, etc.) can fail, resulting in production loss from one or more wells. Because these components can cause the downtime of more than one well, they are modeled separately from the downhole components. Table 3 lists the types of subsea repairs with the percent of wells affected.

*2 - Identify costs associated with each repair operation.* An FMECA identified critical failure modes (mechanical failure, reservoir-related failures, and regulatory driven shutdowns) and determined associated consequences of failures for each well system component. This process identified which operating procedure would be used to achieve the repair. The operating procedure determined the duration of the repair activity and the type(s) of repair resource(s) required for the repair. These repair resources include platform rig, MODU, DSV, MSV, wireline or coiled tubing before a resource vessel can be contracted to perform the based on local conditions. These are easily varied to determine their effect on the total project economics. Well production lost/deferred while waiting on repair resources and during the repair operation are dependent on the number of wells affected by the component failure and on individual well production rate(s) at the time of the failure.

*3 - Determine the frequency of component failure.* Component reliability data that were developed for both RISKEX and RAMEX calculations consisted of estimates of limited failures and extreme failures. For example, a tubing joint has a probability of developing limited leak due to minor damage or improper make-up and a less likely probability of an extreme failure that results in rupture or parting.

All extreme failures were assumed to necessitate a workover. However, a limited failure may or may not cause a stoppage of operations, depending on the size and nature of the failure. Small leaks often cause pressures to increase in the annulus between the tubing string and the production casing. The U.S. Minerals Management Service (MMS) permits production to continue with annulus pressure so long as the pressure build-up is within certain limits. Leaks that are sufficiently small to permit continued operations may eventually increase in size until sustained annular pressure indicate loss of a well control barrier.

The fraction of limited failures that are severe enough to require a workover is defined as the ξ-factor. The failure breakdown is shown in the following.
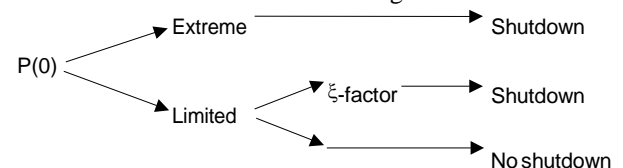
The ξ-factor was estimated to correspond to historical
oxMPrSp                                    nhorheet
pressure for single casing risers mandate the need for a
workover, regardless of the size of the leak.  Therefore, a ξ-
factor of 1 is used for the single casing riser tieback system.

field development system is defined as a simplified,
hierarchical network of completion components. The field
development system can consist of one or more wells; the well
can consist of one or more completion components.

A well is modeled as a list of completion components with
their associated failure modes, corresponding consequences in
terms of reduced production, and required repair resource. A
well is considered to function if all of its components are
functioning (in reliability theory referred to as a series
structure).  The type and number of completion components
may vary from well to well.

The frequency of unplanned workovers can be calculated
using the RAMEX methodology.   Each component failure
mode has a specific workover associated with its repair.
Using the component failure probabilities described earlier, it
is then possible to determine the frequency per year of each
unplanned workover. Unplanned repair frequencies are
calculated for the various types of repair operations.

RAMEX is calculated by multiplying the yearly system
failure probability by the costs associated with lost production
and repairing the system for the particular failure.   This
section will first describe the calculation of the lost production
costs, then describe the repair costs.

The oil/gas production profiles vary over time.   Each
individual well will have a normal production rate, which
sums to the normal daily field production rate.  The individual
well capacity can be larger than the normal rate.

The production consequence for an individual well
depends on the following:

* The production rate at the time the failure occurred
* Lost capacity while waiting on repair resources
* Availability time for the repair resources
* Active repair time

The average production loss per year due to any particular
component is given by the following equation:

$$PL_{year} = \frac{P_a(H) - P_a(L)}{1 \text{ year}} * (T_{AR} + T_{RA}) * PR * 365 \text{ days/year}$$

where: $PL_{year}$ = the production loss cost for a given year,
$P_a(H)$ = the probability of component failure for the end of the
year (e.g. 2 for year 1), $P_a(L)$ = the probability of component
failure for the beginning of the year (e.g. 1 for year 1), $T_{AR}$ =
the mean time to repair a certain failure, $T_{RA}$ = the rig
availability time, $PR$ = the average well flow rate for that
particular year.

The average production loss per year for a given well is the
sum of the losses for all the well components. This concept of
lost production is further illustrated in the following figure,

where: TTF = Time To Failure, LCWR = Lost Capacity while
Waiting on Rig, $T_{RA}$ = Resource Availability Time, $T_{AR}$ =
Active Repair Time).
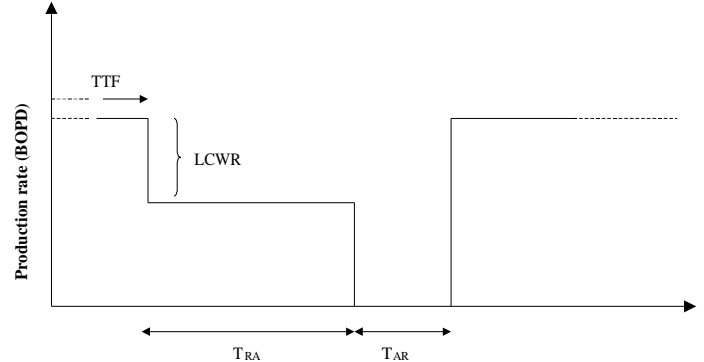


The mean time to repair is dependent upon the operation
used to repair the system. A repair operation is required for
each component failure.

Each operation will have a corresponding repair vessel,
depending on the scenario (dry tree, subsea).

A field production profile prediction provides the basis for
a field development plan.  This field total production rate
prediction is the sum of the individual well production rates.
Processing facilities capacity typically limits the field
wells are
producing at near maximum rates.  The production profile will
production volume over the planned lifetime can be regarded

If the processing facility capacity, at the time of a well
failure, is lower than the rate that can be produced by the non-
failed wells, there is no loss in production rate.  This will
normally be the case during the plateau period.  However, if
the processing facility capacity, at the time of the failure, is
higher than the rate that can be produced by the non-failed
wells, failure will result in a loss of production rate.  This will
normally be the case in the period before the plateau period
(drilling and tie-in of new wells) and the decline phase after
the plateau period.

If the total remaining well flow rate exceeds the production
capacity by more than the flow rate of the failed well, the
production loss is ignored.  However, if the flow rate of a
particular well is more than the difference between the total
well flow rate and the processing facility capacity, the lost
production is the difference between the total field flow rate
and the particular well flow rate.  For calculation purposes, the
following algorithm has been used:

$$LP = \begin{cases} 0 & \text{for } (\sum PR_{remaining} - PFC) > PR_{lostwell} \\ PR_{lostwell} - (\sum PR_{remaining} - PFC) & \text{for } (\sum PR_{remaining} - PFC) < PR_{lostwell} \end{cases}$$

where: $LP$ = lost production for a field in a particular year
(BOPD), $PR_{lost\ well}$ = the production rate of a failed well
(BOPD), $PR_{remaining}$ = the production rate of the rest of the
wells (all minus the failed well) (BOPD), $PFC$ = the
production flow capacity (BOPD).

The repair costs is calculated by multiplying the yearly system failure probability by the mean time to repair the failure and the rig spread cost. For each component failure, there may be a different resource associated with the repair, and hence a different cost. The repair cost is calculated by using the following equation:

$$RC_{year} = \frac{P_a(H) - P_a(L)}{1\ year} * T_{AR} * RSC$$

where: RC = resource cost associated with a particular failure, $T_{AR}$ = the mean time to repair a particular component, RSC = resource spread cost ($/day).

The final RAMEX values are calculated by multiplying the yearly failure probability by the sum of the production costs and the repair costs for a particular failure. This is shown in the following equation:

$$RAMEX_{year} = \sum_{component\ failures} \frac{P_a(H) - P_a(L)}{1\ year} * \{[(T_{RA} + T_{AR}) * LP * 365] + (T_{AR} * RSC)\}$$

where: $RAMEX_{year}$ = the total RAMEX of a particular system for a particular year.

The % uptime is defined as the percentage of the maximum flow capacity of the field over the field lifetime. This percentage is calculated by dividing the well-days attributed to lost production from the total number of well-days in the field life.

The calculation for the % uptime of a dry tree system is shown through the following equation:

$$\%\ uptime_{drytree} = 1 - \frac{\sum_{x=1}^{n} \frac{LPD_x}{W_x}}{D_{total}}$$

where: % uptime$_{drytree}$ = the percentage of maximum flow capacity of the dry trees over the field life, $LPD_x$ = the days of lost production in a given year (x) for the dry trees calculated through RAMEX techniques, $W_x$ = the number of subsea wells for a given year, $D_{total}$ = the total number of well-days in the field life.

The calculation of the % uptime of a subsea system is shown through the following equation:

$$\%\ uptime_{subsea} = 1 - \frac{\sum_{x}^{n} LPSE_x + \sum_{x}^{n} \frac{LPSW_x}{W_x}}{D_{total}}$$

where: % uptime$_{subsea}$ = the percentage of maximum flow capacity of the field over field life, $LPSE_x$ = the days of lost production in a given year (x) for the subsea equipment calculated through RAMEX techniques, $LPSW_x$ = the days of lost production in a given year (x) for the subsea wells calculated through RAMEX techniques.

**Calculate overall lifecycle cost (CAPEX, OPEX, RISKEX, RAMEX).** The CAPEX, OPEX and the Risk Cost will appear during different times in the field life. The net present value of future costs was used to take the time value of money into account. The lifetime cost was calculated by:

$$Lifecycle\ Cost = CAPEX + OPEX + RISKEX + RAMEX$$
$$= CAPEX + \sum_{k \in \{1,N\}} \frac{OPEX}{(1+r)^k} + \sum_{k \in \{1,N\}} \frac{RISKEX}{(1+r)^k} + \sum_{k \in \{1,N\}} \frac{RAMEX}{(1+r)^k}$$

where: OPEX$_i$ and RC$_i$ represent the OPEX and Risk Cost in year i respectively, r is the discount rate and N is the field life in years.

## Base Case Subsea System

A 6-well satellite clustered subsea system design was developed to demonstrate the model. Figure 1 shows the overall layout for the base case 6-well subsea system. The subsea system includes hydraulic and electrical umbilicals and pipeline connecting the subsea system to a remote host platform. Flowline jumpers connect the pipeline end manifolds to a 6-well manifold and well jumpers connect the manifold to individual wells that are clustered around the manifold. Hydraulic and electrical flying leads connect the hydraulic and electrical termination units to individual wells.

The methodology and spreahsheet tool has been expanded to model additional subsea facilities with pipeline umbilical extensions to an additional subsea manifold with associated wells. This permits the evaluation of a variety of subsea configurations and numbers of wells.

A schematic of the conventional tree used in the base case is displayed in Figure 2. The tree consists of a 4-inch vertical access production bore with wireline plug access to the tubing hanger via the tree. The annulus bore is 2-inch nominal with direct wireline access to the tubing hanger annulus.

The horizontal tree connects directly to the subsea wellhead system. The horizontal tree design eliminates a tubing head spool as presently found in the base case vertical tree system. The horizontal tree assembly will carry the flowline hub enabling vertical well jumper connections between the tree and manifold. Figure 3 displays the base case horizontal tree configuration.

## Case Examples

The methodology and spreadsheet program developed by this JIP has been used to quantify the CAPEX, OPEX, RISKEX and RAMEX factors that determine the differences in these well systems. The following sections describe results and conclusions derived from evaluation of numerous case examples.

*Dry Tree Tieback Systems.* We have compared three dry-tree well systems for a case example: dual casing riser, single casing riser and tubing riser. The base case input data are summarized in Table 1 and the lifecycle costs are presented in Table 2 and Figure 4. The results indicate that a dual casing riser is the most cost efficient. The single casing system is differentiated by its high RISKEX and the tubing riser system is differentiated by its high OPEX and RAMEX. Note, however, that the base case is located in deep water (4000 feet) and produces from a high-pressure reservoir.

Single casing risers provide an ideal solution for shallow water and moderately deep water when formation pressures

are very near seawater gradient. Because well interventions are performed with a surface BOP stack through the single casing riser, a small leak in a single casing riser can cause loss of well control in deepwater when formation pressures are abnormal. RISKEX during well intervention operations is quite high in this case. RAMEX is higher than for a dual casing riser because any annular pressure requires an immediate intervention.

Dual casing risers provide the added well control for intervention operation to minimize RISKEX. Well interventions are performed with a surface BOP stack through the dual casing riser. CAPEX is typically $1 to $2 million dollars per well more than a single casing riser in moderate water depths. OPEX for dual casing risers is slightly higher than OPEX for single casing risers are because it takes a bit longer to install the inner riser. RAMEX for dual casing risers is less than RAMEX for single casing riser because production can continue with small annular pressures. When CAPEX, OPEX, RISKEX and RAMEX are all considered the dual casing riser system is the most economical alternative for deepwater developments where reservoirs are abnormally pressured.

The tubing riser system includes a master valve (essentially a subsea tree) at the mudline to provide well control in the event that the tubing riser or surface tree leaks. This system has great attraction to platform designer because it might significantly reduce the riser load carried by the platform. This could significantly reduce platform size and cost. Well interventions require the tubing and subsea master valve to be removed and a well intervention riser system is installed. We have considered two well intervention riser systems: (1) a high pressure single wall riser with seafloor shear ram and surface BOP stack and (2) a dual wall drilling riser. Tubing riser system OPEX is significantly higher than dual or single casing riser systems because of additional rig time needed to change these riser systems before and after any well intervention. A moonpool is required in the platform to run a conventional subsea master valve system or subsea shear ram. An umbilical for annular access, and controls for the subsea master valve, SCSSV, and other downhole components will be about the size of the tubing riser. This dual-parallel riser configuration presents significant problem in analyzing for vortex induced vibration. This single-wall riser may also experience problems of hydrate or paraffin plugging due to cooling.

*Subsea Production Systems*. The results of a case example of subsea well systems are shown in Table 4 and Figure 3. Input data presented in Table 1 were used for this example. The results indicate that the horizontal tree system is the most economical for the base case and both cases are dominated by the RAMEX.

Horizontal subsea tree system permits workover operations without removing the subsea trees. This system is most economical if numerous workovers are required for recompletions to new zones.

Conventional subsea trees can be replaced more easily than horizontal trees in the event of the failure of a tree valve or actuator. Conventional subsea trees can be replaced without pulling the completions string; horizontal subsea trees require the completion string to be pulled prior to pulling the tree. Therefore, the most economical type of tree is influenced by the reliability of the tree components such as valves, valve actuators, connectors, etc.

Subsea production systems have several unique advantages. CAPEX can be much less than for a new platform facility when an existing facility is available to accept production from a subsea production system. RISKEX is relatively low for subsea systems. Table 4 and Figure 3 show that RAMEX and OPEX can be significantly higher than dry-tree systems, depending on reservoir characteristics. The daily spread cost for a MODU is about twice that of a platform rig operation and it takes almost twice as long for most well much longer than dry-tree intervention operations. Therefore, subsea well interventions cost three to four times as much as dry-tree interventions.

Smart completions may be useful to minimize RAMEX for subsea wells. Smart or intelligent completions have the potential to:

- Remotely and inexpensively isolate a depleted zone and initiate flow from a new productive zone, regulate the flow from adjacent zones to maximize recoveries and reservoir performance, remotely achieve other changes in downhole configurations.
- The use of a smart completion for zonal re-completion when the primary zone is depleted provides the potential to eliminate an expensive workover.

This potential saving is partially offset by several smaller costs. The alternate zone must be properly completed with an appropriate sand control system, thus, increasing the initial well cost and perhaps delaying production. Reservoir characteristics are better understood after several years of production, thus, permitting improved re-completion designs. Smart completion tools cost more to install and because of increased complexity are more likely to fail, requiring an unplanned workover.

The net present value (NPV) of a smart completion CAPEX must be compared to the NPV of a later workover and the system RISKEX and RAMEX to determine the most cost effective development plan.

## Acknowledgements

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Technology Conference, Stavanger, Norway, October 1999.

Production
Houston, USA

Effective and Safe Deepwater Completion Tieback
(OTC 12167).

## Terms and Acronyms

CAPEX – CAPital EXpenditures

DSV – Drilling Service Vessel

DTTAS – Dry Tree Tieback Alternative Study

FMEA – Failure Modes and Effects Analysis

FMECA – Failure Modes, Effects, and Criticality Analysis

JIP – Joint Industry Project

MMS – Minerals and Management Service

MODU – Mobile Offshore Drilling Unit

MSV – Multi-Service Vessel

PLEM – Pipeline End Manifold

OPEX – OPerational EXpenditures

RAMEX – Reliability-Availability-Maintainability EXpenditures

RISKEX – RISK EXpenditures

TLP – Tension Leg Platform

$\xi$- factor – Ratio of limited leaks that will necessitate a workover

AXV – Annulus cross-over valve

PWV – Production wing valve

AV – Annulus vent

LMV – Lower master valve

PSV – Production safety valve

CID – Chemical injection downhole

CIT – Chemical injection tree

FIV – Flowline isolation valve

AMV – Annulus master valve

ASV – Annulus swab valve

AWV – Annulus wing valve

**Figure 1:    Satellite Cluster**
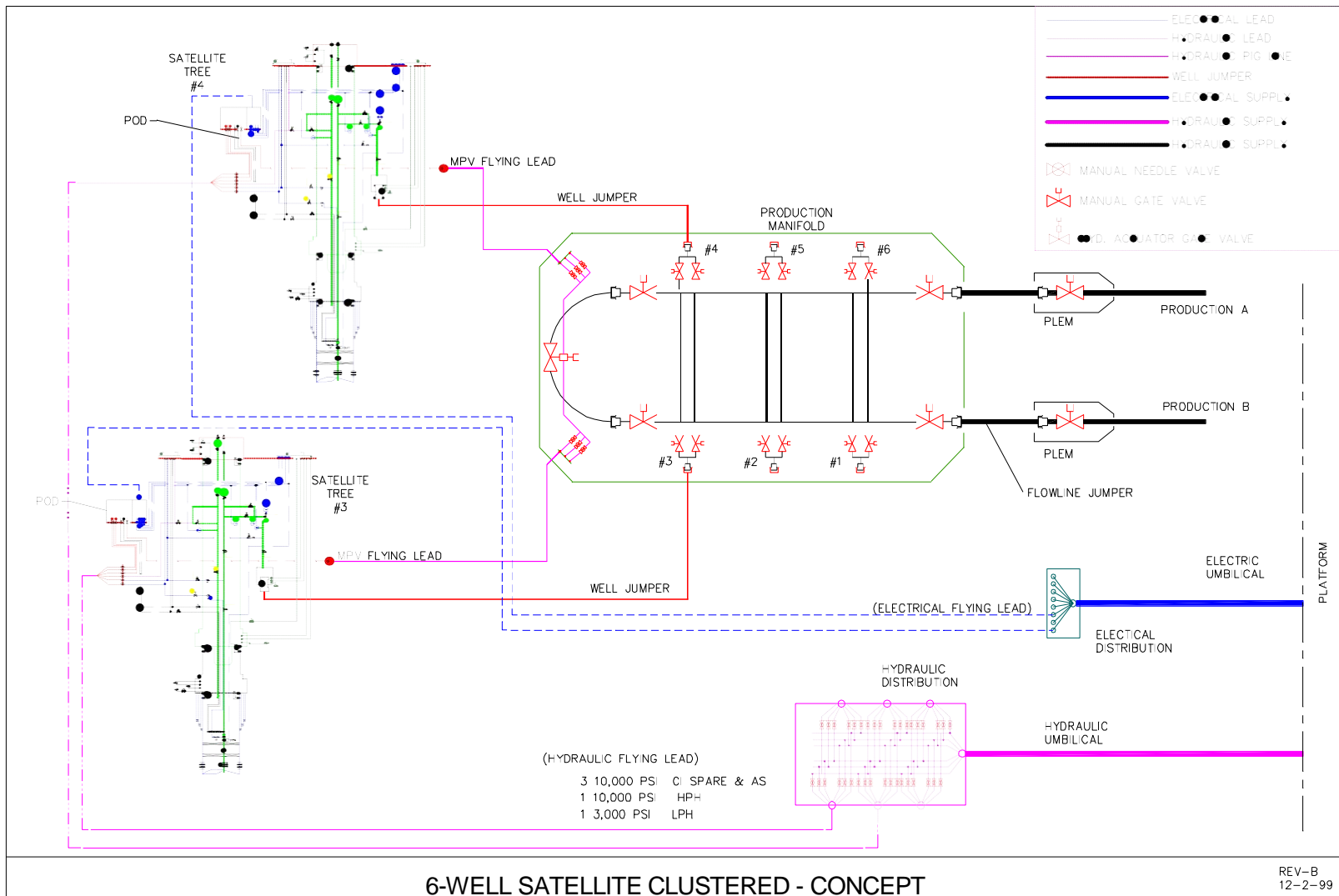


6-WELL SATELLITE CLUSTERED - CONCEPT

**Figure 2: Conventional/Vertical Tree Schematic**
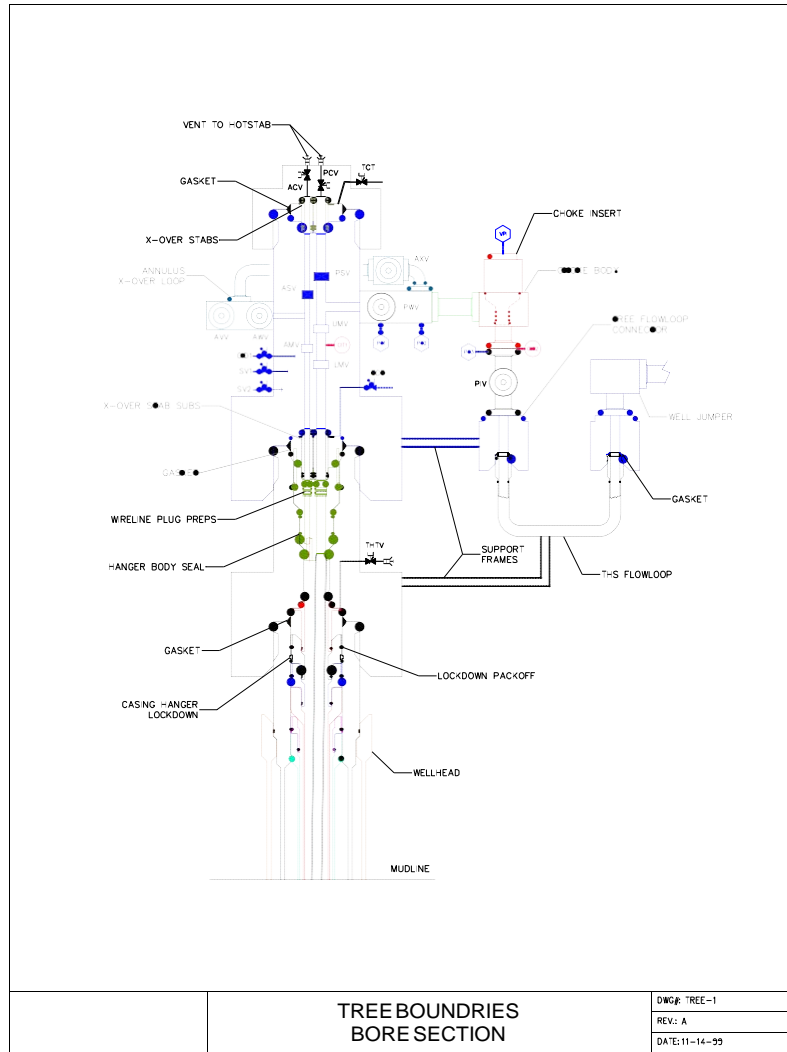


**Figure 3: Horizontal Tree Schematic**
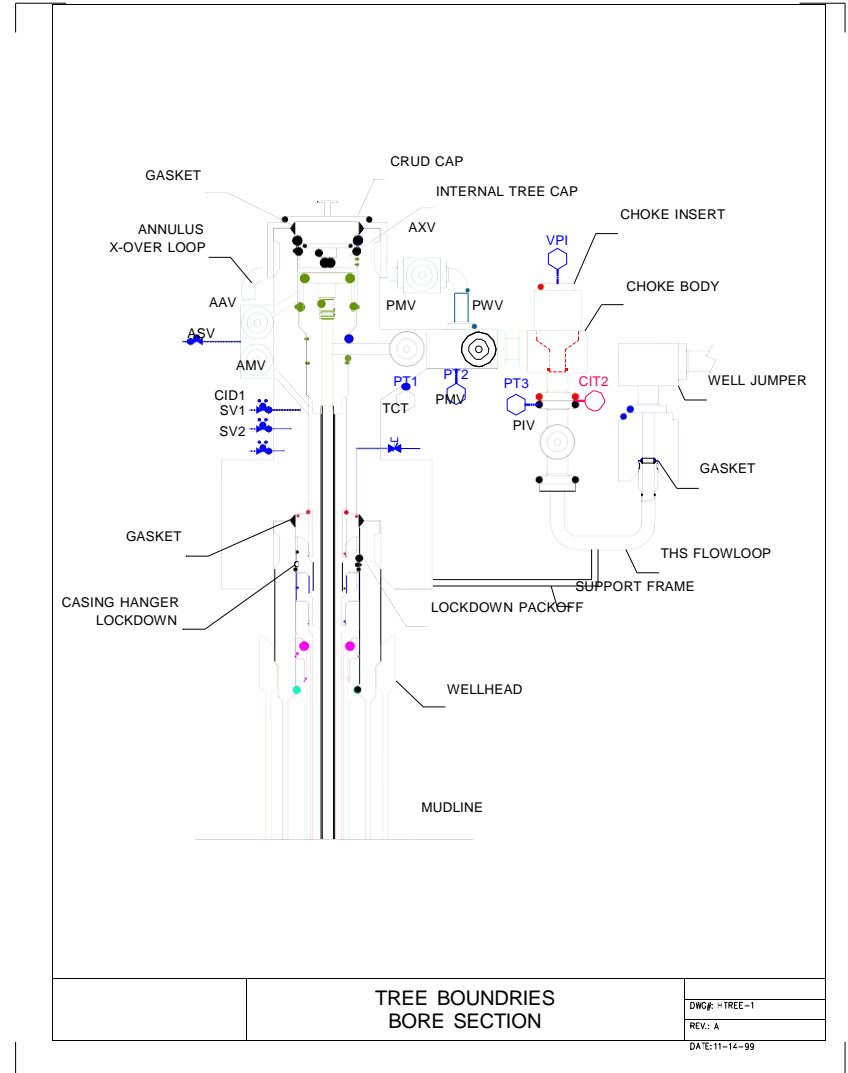
**Table 1:    Case Study Input Data**

| | INPUT DATA |
|---|---|
| Field Life (years) | 10 |
| # of wells | 6 |
| Water depth (feet) | 4,000 |
| Zone depth (feet BLM) | 10,000 |
| Pipeline size (in) - for subsea equipment | 12 |
| Pipeline length (mi) – for subsea equipment | 35 |
| Infield extension (mi) – for subsea equipment | 5 |
| Facilities processing limit (MBOPD) | No limit |
| Oil op. margin in year produced ($/bbl) | 8 |
| Discount rate for NPV calculations (%) | 15 |
| Number of unplanned tree replacements | 2 |
| Number of unplanned downhole repairs | 2.5 |
| Number of unplanned sand control repairs | 5 |
| Recoverable reserves per zone (MM BO) | 22 |
| Initial production rate (M BOPD) | 15 |
| Decline rate (%/year) | 10 |
| Ratio frac pack – horizontal wells | 1:1 |
| Ratio planned uphole frac packs–sidetrack frac packs–sidetrack horizontals | 1:1:1 |
| Limited uncontrolled release cost ($ / BOPD) | $1,700 |
| Major uncontrolled release cost ($ / BOPD) | $35,000 |
| Extreme uncontrolled release cost ($ / BOPD) | $250,000 |

**Figure 4:    Dry Tree Completion Alternatives Lifecycle Cost ($MM NPV)– 6 wells, 4000 ft**

| | Dual Casing | Single Casing | Tubing Riser |
|---|---|---|---|
| Total Cost ($MM) | 193 | 242 | 212 |
| RAMEX ($MM) | 76 | 84 | 95 |
| RISKEX ($MM) | 1 | 61 | 4 |
| OPEX ($MM) | 15 | 15 | 23 |
| CAPEX ($MM) | 101 | 81 | 91 |
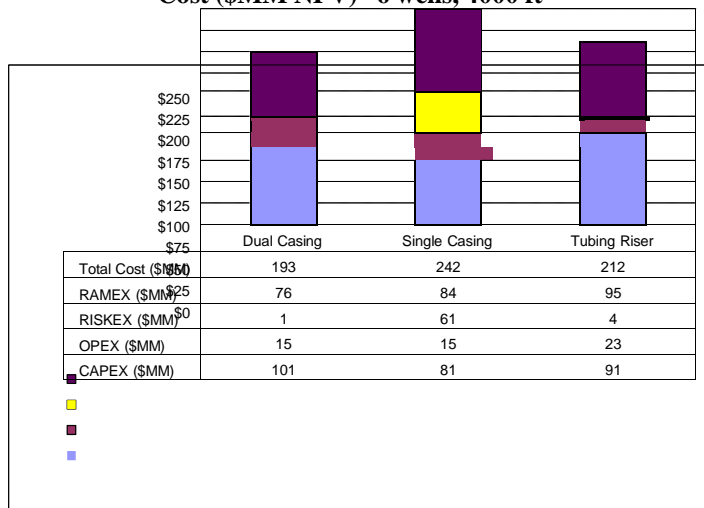
**Table 2:    Dry Tree Completion Alternatives RAMEX Results – 6 wells, 4000 ft**

| | | | |
|---|---|---|---|
| | 98.0 % | 97.8 % | 97.8 % |
| | 11.4 | 12.0 | 15.7 |
| | 25.6 | 29.1 | 28.9 |
| | **37.0** | **41.1** | **44.6** |

**Table 3:   Subsea Equipment Repair Costs**

| Subsea Repair Type | % of Wells Affected |
|---|---|
| Repair / Replace Hydraulic System Umbilical | 100% |
| Repair / Replace Electrical System Umbilical | 100% |
| Repair / Replace Hydraulic Extension Umbilical only if > 8 wells | 100% |
| Repair / Replace Electrical Extension Umbilical only if > 8 wells | 100% |
| Repair Pipeline or PLEM | 50% |
| Repair / Replace Flowline Jumper | 50% |
| Repair Extension Pipeline or PLEM only if > 8 wells | 50% |
| Repair / Replace Extension Jumper only if > 8 wells | 50% |
| Repair / Replace Tree Jumper Extension only if > 8 wells | One well |
| Repair/ Replace Tree Jumper | One well |
| Repair / Replace Well Jumper | One well |
| Repair / Replace Well Flying Leads | One well |
| Repair / Replace Well Control Pod | One well |
| Repair / Replace Well Subsea Choke | One well |

**Table 4:   Subsea Completion Alternatives RAMEX Results – 6 wells, 4000 ft**

| | | |
|---|---|---|
| | 89.6 % | 89.6 % |
| | 69.4 | 64.1 |
| | 132.3 | 131.9 |
| | **201.7** | **196.0** |

**Figure 3:   Dry Tree Completion Alternatives Lifecycle Cost ($MM NPV)– 6 wells, 4000 ft**



| | Conventional | Horizontal |
|---|---|---|
| Total Cost ($MM) | 950 | 903 |
| ■ RAMEX ($MM) | 464 | 445 |
| □ RISKEX ($MM) | 5 | 5 |
| ■ OPEX ($MM) | 88 | 74 |
| □ CAPEX ($MM) | 393 | 379 |