WELL ENGINEERING CONCEPTS TO MAKE METHANE GAS HYDRATE EXPLOITATION AFFORDABLE

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The thesis is submitted in partial fulfilment of the requirements for the degree of Doctor of Engineering at The Robert Gordon University, Aberdeen.

Declaration

This thesis is submitted to the Robert Gordon University in accordance with the requirements of the degree of Doctor of Engineering, in the School of Engineering. I can confirm that the material presented in this thesis is my own work. Where this is not the case, the source material has been acknowledged.

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Date	June 2011

Abstract

There are anticipated to be substantial global deposits of land and seabed methane gas hydrates. The volume of methane gas trapped in these methane gas hydrates is calculated to be at least twice the volume of current global reserves of oil & gas as reviewed by the United Nations. These methane gas hydrates are deemed important as a future energy resource, and several companies and countries are looking at the effective exploitation of the resource for methane gas supply. If safe economic exploitation could be achieved the world will have an energy resource that would be able to support the demands for century's to come. The chemistry, physics and geological setting of the natural hydrates make them difficult to exploit using convention hydrocarbon well engineering techniques. The major nations of the world such as the United States of America, Japan, Canada, France and Germany are investing heavily in research and development to gain a better understanding of the gas hydrate energy source. It is an area that we will see confirmed as a major energy source for the world, provided the costs of development can be reduced. In the perma frost land environment and deep sea marine environment Hydrates have traditionally been seen as a major risk to Drilling operations and have been implicated with many drill well blowouts world wide. This thesis critically reviews the existing industry approaches to hydrate exploitation and proposes several new well engineering techniques, which could be applied to effect successful resource recovery. This thesis derives the conclusion that by an enhanced understanding of the deposit area and by the application of new well technology and varied procedures, methane exploitation will be possible.

The thesis focused on three areas to reduce cost of development:

1. Low cost, low complexity, subsea systems to drill produce and maintain developments.

2. Utilisation of fit for purpose low cost vessels to conduct the field development drilling and completion.

3. Seabed drilling topdrive system to enable rapid drilling of the development.

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Abbreviations

AFE	Authorisation For Expenditure
ALARP	As Low As Reasonably Practicable
BBLS	Barrels
BHA	Bottom Hole Assembly
BOP	Blow Out Preventer
BSR	Bottom Simulating Reflection
CCF	Central Cormorant Field
CNG	Compressed natural gas
DLA	Drill Lock Assembly
DPV	Dynamically Positioned Vessel
DSDP	Deep Sea Drilling Project
FDP	Field Development Plan
FLNG	Floating Liquid Natural Gas
FSR	Financial Stability Revue
GOM	Gulf of Mexico
HSE	Health and Safety Executive
HSZ	Hydrate Stability Zone
IP	Intellectual Property
JIP	Joint Industry Project
LELs	Low Explosive Levels
LIP	Locked In Potential
LNG	Liquefied Natural Gas
LWD	Logging Whilst Drilling
MWD	Measurement Whilst Drilling
NPV	Net Present Value
ODP	Ocean Drilling Project
PDC	Polycrystalline Diamond Compact
PWD	Pressure Whilst Drilling

R & D	Research and Development
ROV	Remotely Operated Vehicle
SCFD	Standard Cubic Feet per Day
SCM	Subsea Control Module
SEC	Securities and Exchange Commission
SFR	Scope For Recovery
TCF	Trillion Cubic Feet
TD	Total Depth
UR	Ultimate Recovery
VOI	Value Of Information
VS	Versus

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1 General Introduction

Global deposits of methane gas hydrates are of such significance to the future of the world as an energy source (1), that many national programmes (2) are investing hugely in the research and development needed to bring forward suitable technologies to allow development of these resources in a cost effective manner. The major investors are United States of America, Japan and India. More recently both France and Germany are reported (3) by the U.S. Mineral Management Agency as taking a more active interest in this emerging energy source, and are reported as having started investment and research and development programmes of their own.

1.1 Research Background

Today we have a lack of means for economic development of seabed methane gas hydrates and in particular we are unable to accurately provide;

- Geophysical acquisition and interpretation techniques that can detect hydrates, and gas bearing zones beneath hydrates.
- Quantification of the saturation and pore scale distribution.
- Mature static or dynamic reservoir modelling capabilities for gas hydrate reservoirs.
- Production engineering techniques that can deliver gas to surface.
- Lower cost Well Engineering techniques for hydrate drilling.
- Lower cost Well Engineering techniques for hydrate production.
- Safety of exploitation.
- Economic evaluation.

1.2 Aims and Objectives

The aim of this project is to research seabed natural gas hydrates, with a view to offering effective technical solutions for the choice of subsea systems and drilling methods in future hydrate field development. Technical, economic criteria will be qualitatively considered in order to develop a generic, affordable well engineering solution for the subsea systems. The findings and recommendations are expected to be of prime importance in future natural gas hydrate development.

In order to achieve this, and contribute favourably to theory and practice, the following specific objectives have been outlined:

- Overview of subsea gas hydrate development and its evolution.
- Review of various hydrate exploitation systems and configurations of well design, well layouts and gas production options.
- Provide some criteria as a platform upon which the screening tool for economical development will be developed.
- Develop the screening tool using qualitative analysis.
- Finally, make conclusions and recommendations on how gas hydrates can be developed in a cost effective manner.

1.3 Project Limitations and Constraints

Limited well engineering work has been done in the area of deepwater seabed exploitation of naturally occurring gas hydrates.

Literature searches encountered difficulty in getting useful data on hydrate well / field development for analysis as much of the third party research is confidential.

2 Literature Search

2.1 What are hydrates?

Natural gas hydrates (or "clathrates") are crystalline compounds formed by water with natural gases and associated liquids. The hydrates are solid ice-like substances composed of cages or lattices of water molecules (host), which are capable of accepting guest molecules of gas such as nitrogen, chlorine, methane, ethane and others, determined by the guest molecular size and how it fits inside the lattice structure (4). Sir Humphrey Davy first discovered hydrates accidentally in 1811 whilst testing Chlorine gas. Unlike pure ice, hydrates can form at temperatures above the freezing point of water.

In the hydrocarbon industry hydrates can form in gas, gas condensate and black oil systems. Basically they require four components to allow formation. These are pressure, low temperature, gas and water. Removal of any one of these will prevent hydrate formation.

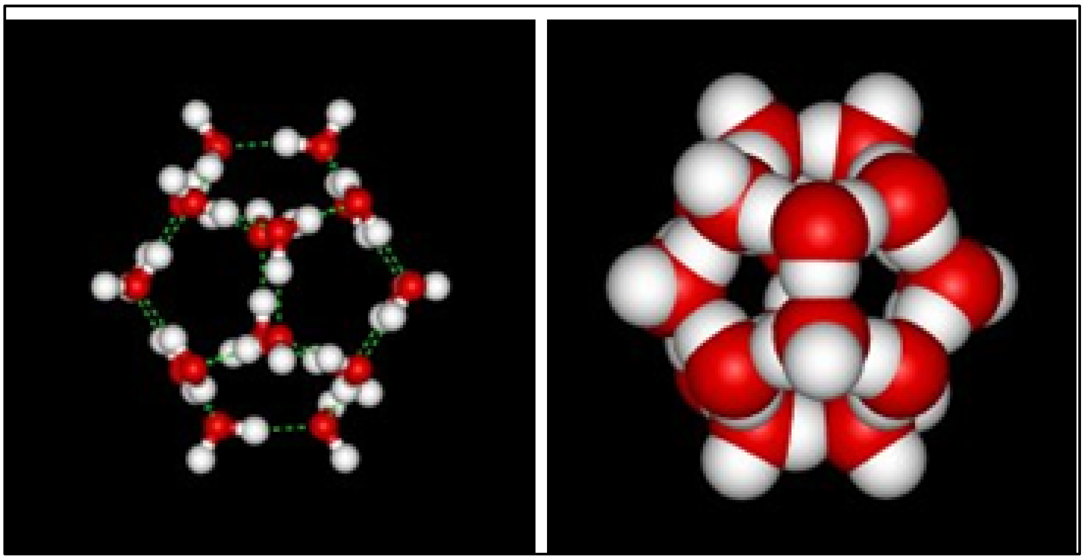

Figure 1: Typical Hydrate Formation (4)

Gas hydrates are solid compounds, which can form anywhere when water contacts hydrocarbon gases such as methane, ethane and other small molecular gases. The pressure-temperature region in which hydrates are stable depends on the composition of the production stream and this is accurately predictable by computer models. Gas hydrates are approximately ninety percent water and ten percent gas in volumetric terms (5) : 150m^3 of natural gas can combine with 0.8m^3 of water to yield 1m^3 of gas hydrate. Gas hydrate formation and dissociation is chemically fully reversible. This means that gas and water from which gas hydrates are formed, can be restored chemically unaltered if the hydrates are melted.

The texture of gas hydrates is similar to that of ice, with agglomerates of hydrate crystals appearing as a white snow-like compound. Like ice and snow hydrate crystals tend to stick together to form accumulations, which can be a barrier to the passage of hydrocarbon product, or to well intervention tools. Gas hydrate density is typically 0.9g/cm^3 (6), but varies slightly dependent upon the concentration of methane (and any other gases which may be present) in the structure.

2.2 What are seabed hydrates?

Seabed hydrates are formed in marine sediments and are stable at water depths greater than 500 metres provided the pressure, temperature, gas and pore space conditions are suitable. The formation of these seabed hydrates fosters a cementation of the loose sedimentary layer on the seabed and can be present in hundreds of metres of sediment. This has been confirmed by industry well drilling reports (7) where hydrates have been encountered below the seabed, and have been measured as extending to hundreds of metres thick. The seabed conditions required are low temperature, water pressure (provided by the hydrostatic pressure), water (contained within the pore space of the lithology column) and methane. Methane is generated by bacterial degradation of organic matter or thermogenic processes. The hydrates are accumulated within the lithology column in an area where they are stable. This is called the hydrate stability zone (HSZ) (8) and this zone can extend to several hundreds of metres thick.

Figure 2 depicts a phase diagram with pressure at depth and temperature to create the hydrate stability zone in the lithology column.

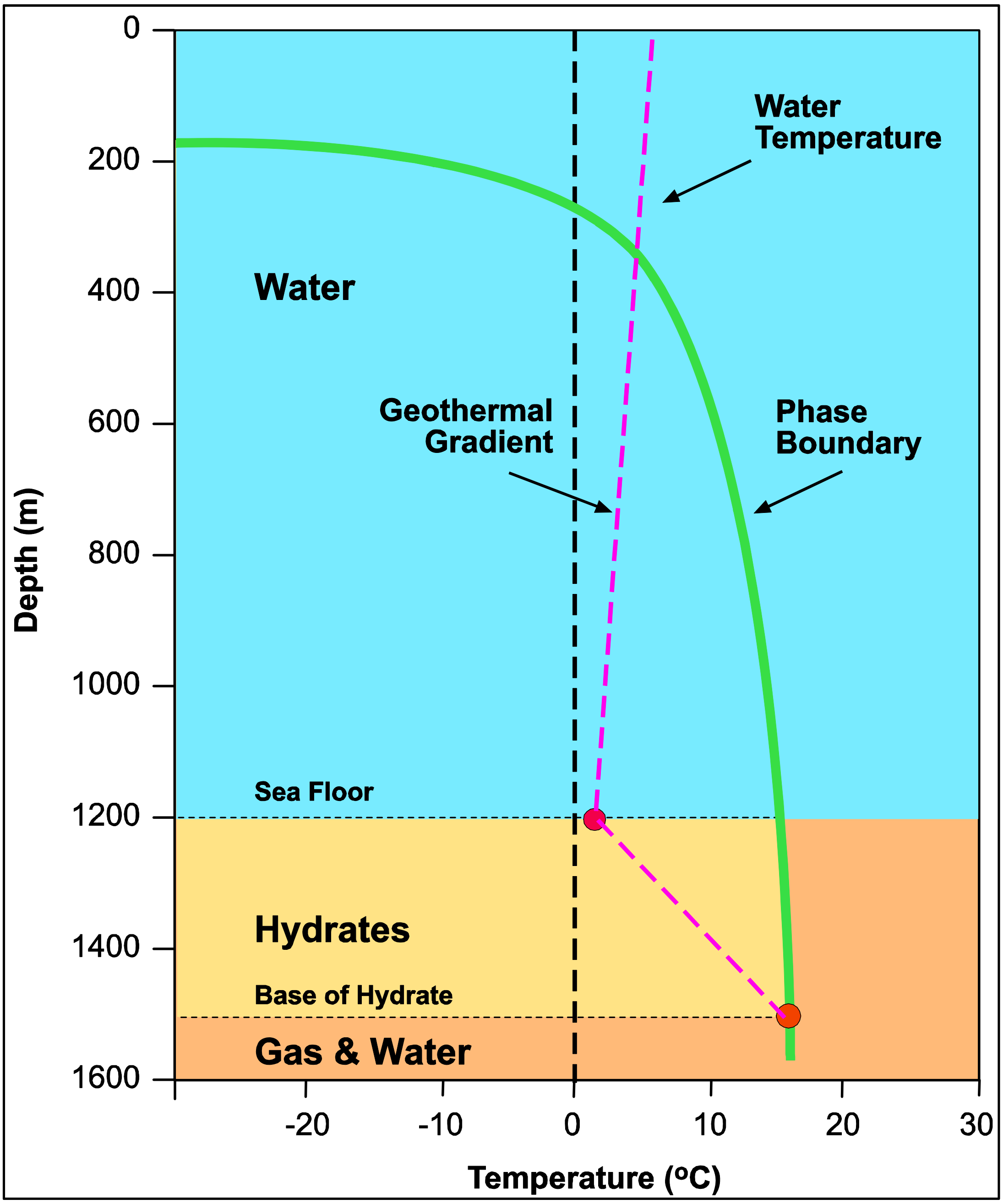

Figure 2: Phase Diagram showing hydrate stability zone. (9)

Seismic reflection profiling has been used very successfully by the oil industry to identify and exploit hydrocarbon deposits. This has been successful because of the ability to calibrate the seismic reflection profile against the sandstone properties when containing hydrocarbons (oil, gas) or water. From this calibration interpretation of the seismic information, traces can be made to identify areas rich in gas, oil or water. Thus allowing the reservoir targets to be selected for exploitation. Little is known about hydrate sedimentary properties and, therefore, lithology calibration work is required to align the fingerprint of the seismic trace with the hydrate stability zone sedimentary properties.

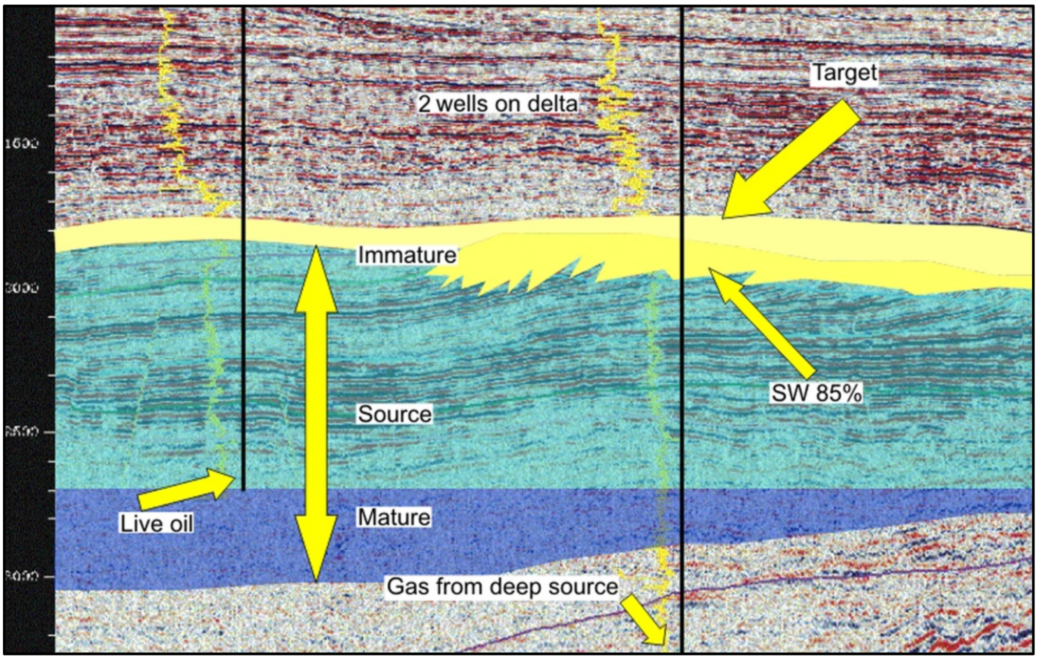

Figure 3: Detail of a seismic trace showing hydrate accumulations in yellow (10)

Whereas biogenic formation of methane may take place both in situ within the HSZ and beneath it, thermogenic methane must move upward into the HSZ in order to act as a supply for hydrate formation. During thermogenic generation of methane, a considerable amount of higher-molecular-weight hydrocarbons is produced; this is a clear indicator for methane source.

Generation of methane formed either thermogenically or biogenically beneath the HSZ could imply upward migration of methane into the HSZ, either as bubbles or dissolved in fluids. If the HSZ moves relative to the lithology column, either upward or downward, the hydrates will dissolve to form water and methane. The methane is then available to move back into the HSZ by migration. The mechanism to move the HSZ up or down could be burial or ocean level change.

Hydrates have been found

(1) Finely disseminated.

(2) As small nodules.

(3) Interlayered with sediment layers.

(4) As massive hydrates such as those found at Deep Sea Drilling Project (DSDP) site 570.

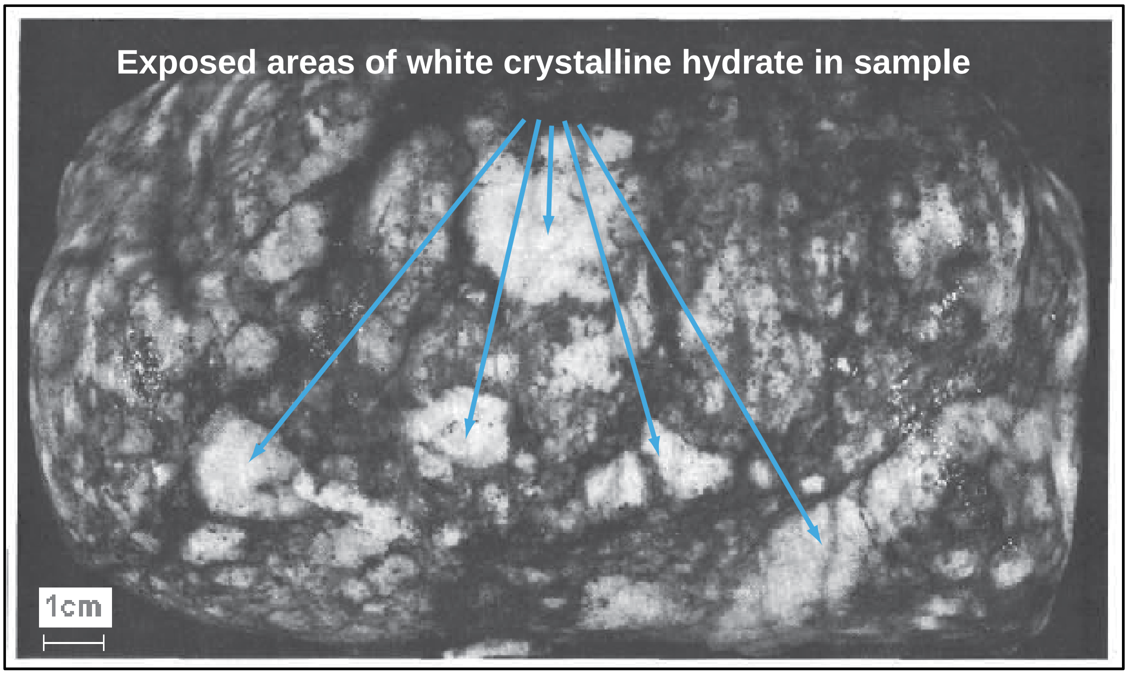

Figure 4: Portion of massive gas hydrate in Core, site 570 (11)

2.3 Global Resources and Locations

Gas hydrates are present in two sedimentary environments. These are the high porosity seabed sedimentary environments, found at the edges of deepwater continental shelves worldwide, and in onshore Arctic sandstone environments. For over thirty years expeditions have been undertaken to many deepwater continental shelf areas to investigate the potential of these seabed occurring hydrates. The investigations are being pursued by many of the major countries of the world with the United States of America investing heavily. Other countries, with little available hydrocarbon stocks, are also playing a key part (such as Japan and India). The surveys have been well described in many articles, books and papers (12), (13), (14) and it is a generally held view that as much as two times the worlds existing hydrocarbon resource stock could be held in seabed hydrates. The motivation for the countries of the world is simple: to tap into this incredible volume of locked in potential (LIP). The challenge, of course, is to tap into it in a manner that is safe and economical. Both these aspects are challenges and much of the hydrate volumetric capacity has been attributed in a manner inconsistent with the more scientifically meticulous classification of proven reserves currently being used by the oil industry as defined by the Security and Exchange Commission (SEC) (15) guidelines.

The accuracy of global resources, therefore, must remain in some doubt until such time as an accurate means of determining the distribution and concentration of hydrates has been realised. This is a major risk to countries that are investing in hydrates – the resource might be less than predicted. Currently, no means exists to model what the area of deposit for methane gas-hydrate occurrences, as explored in the Deep Sea Drilling Project (DSDP) or the Ocean Drilling Project (ODP), could be.

The hydrate gas yield is reported as being of the order 164 m^3 per m^3 of hydrate (5). This will need to be further confirmed by modelling, and from well test results.

Estimations of the actual hydrate volumetric distribution are variable and many estimates have been offered. The table below lists these estimates in an attempt to depict the variation in volume, and give a sense of the uncertainty surrounding all estimations.

Table 1 details from many referenced works, the distribution of volume associated with methane gas hydrate deposits ranging from 35 thousand trillion to 4.9 million trillion cubic feet.

Table 1: Hydrate Volumetric Distribution Estimate (16), (17)

Methane Gas ($x10^{15}$ Cubic Feet)	Reference
180 - 880	Trofimuk et al. (1977)
110	McIver (1981)
270	Dobryin et al. (1981)
620	Kvenvolden (1988)
690	MacDonald (1990)
930 – 4,910	Gornitz and Fung (1994)
35 - 170	Milkov (2004)
4,200	Klauda and Sandler (2005)

These methane gas hydrates are located around the world's oceans at the continental plate margins as depicted in Figure 5, or on land especially in Siberia and Alaska.

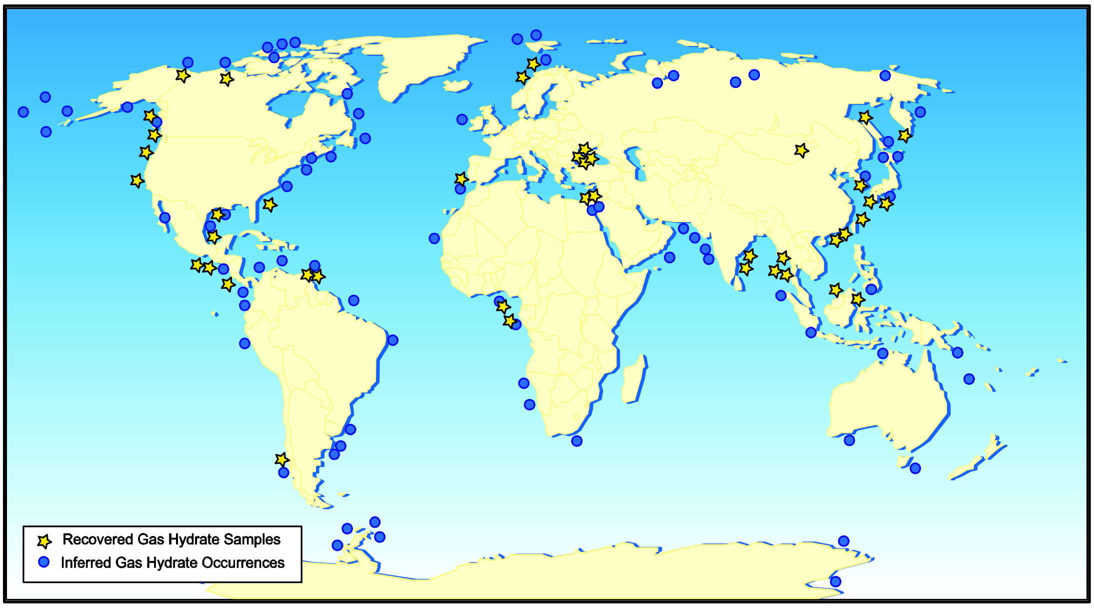

Figure 5: Hydrate Locations (16)

2.4 Gas Market Prospects

Whilst there is some movement in gas markets (and the movement of the energy industry from coal fired electricity stations to gas fired electricity stations) it is still recognised by the major energy suppliers that plentiful low cost gas supplies will be available in land and shallow water locations for the next two decades. Thereafter (circa 2020-2030), gas supplies will need to be developed from deepwater horizons. In this case, the economic profile is such that methane gas hydrate production needs to become economically viable (based on current well technology) by 2030 onwards if it is to be a potential replacement gas source for the market.

The Committee Journal of the International Gas Union concluded in their report "Development prospects for gas supply and demand worldwide 2000 – 2030 (18) that a high level of supply would be sustained until 2030, and even beyond. Since supply and demand are not balanced globally, the Committee Journal suggests that the gas trade could quadruple over the next 30 years, and, therefore large investment will be required to satisfy this demand. It is worth noting that this investment will have to be for conventional deep reservoir gas recovery in deepwater areas of the oceans, as the shallow water and land based gas stocks will have been largely exhausted. This is the time when the economics of these deepwater resources will be in direct competition with a methane gas hydrate supply solution.

In the conceptual picture (Figure 6) of price development for conventional gas and gas from hydrates, the axes are deliberately not detailed, but the depiction shows a crossover point when hydrates need to be in the gas supply portfolio. This is estimated to be about 2030. Much depends on the shale gas industry growth potential and societies support for the continued expansion of these types of gas developments.

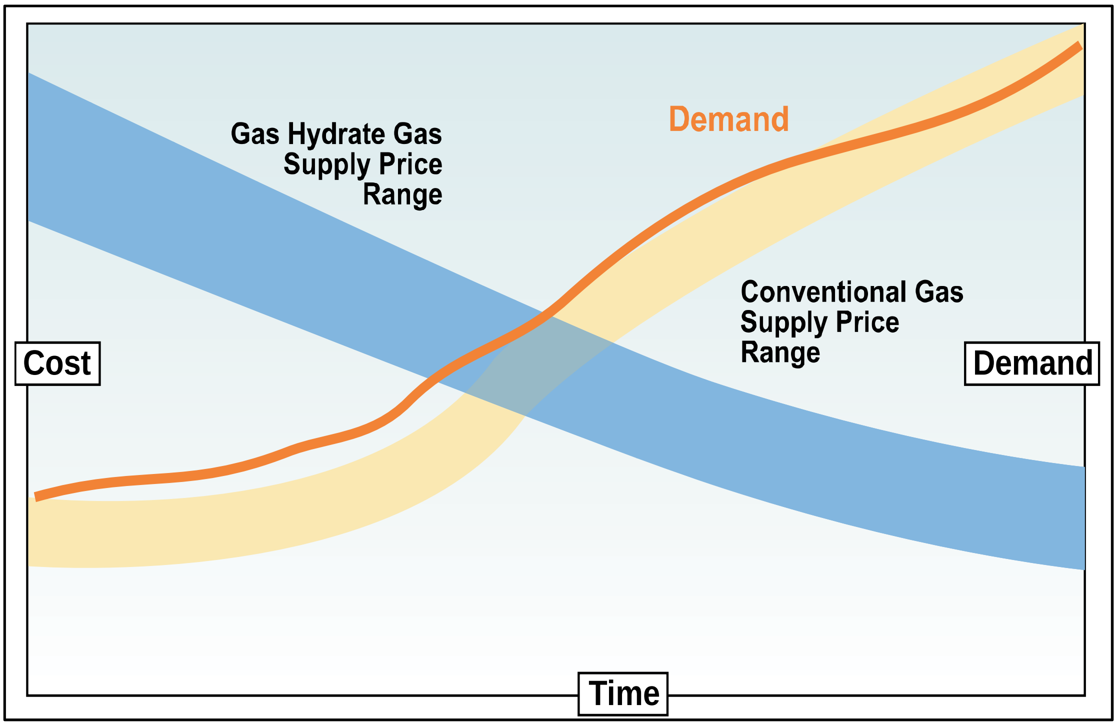

Figure 6: Gas Supply Price Comparison (19)

The market potential, as described by the Energy Information Administration of the US Department of Energy forecasts (20) a worldwide increase of 30-35% in gas consumption between 2007 and 2035, while specific areas, such as Asia and the Middle East, are forecast to double consumption by 2035.

It is clear that the market has a demand for gas, and the timeline is offered by world analysts as indefinitely (21). It is also clear that this gas supply will experience an upward trend in time as a consequence of the pressure to meet demand and to compensate for recovery costs. It is, therefore, concluded that methane gas hydrates extraction technology needs to be in place by about 2015, when the move from conventional to hydrate gas occurs. At the same time as the technology being mature, the extraction economics needs to be equivalent or lower than conventional deepwater recovery economics.

2.4.1 **Alternate Fuel Competition.**

A clear market alternative will come from alternative fuel energy sources. Therefore, market intelligence will need to be closely scrutinised over the development period. The emerging fuel of the future is proposed as hydrogen, and it is envisaged that low cost hydrogen production from hydrocarbons (methane) or water, has the potential to become a widely used, readily-available fuel. Shell Hydrogen is actively involved with the California Fuel Cell Partnership (22), in the development, and testing on road conditions, of a fuel-cell driven car. There is a hydrogen filling station as an integral part of the project. It is envisaged by Shell Hydrogen that pure hydrogen fuel-cell cars will be in mainstream use by 2020. It is, therefore, important that low cost hydrocarbons are available to allow hydrogen production to be a simple low cost alternative. Then hydrogen fuel can be a competitor in the energy market of the future.

Figure 7: Hydrogen Filling Station (19)

The emerging electrical generation technologies, such as offshore wind, wave and tidal stream will also provide a market threat to the exploitation of hydrates. If the above electrical technologies are commercialised on a large scale, then they may have the capability of removing the gas requirement of many nations, who have the appropriate wind, or marine resources.

2.5 Geological setting

Seabed hydrates have been found mostly in subduction basins, along active continental plate margins (Figure 8), where a plate has over-ridden another plate (as in the Pacific trenches of Peru, Middle American Trench, North California, Cascadia, Okushiri Ridge and others). However, hydrates have also been found in passive margins such as the Blake Ridge and in the Black Sea (Figure 9), (where they are associated with a mud volcano).

In an active or passive margin hydrates form in the lithology column at conditions of pressures and temperatures suitable for them as detailed in an earlier phase diagram (Figure 2).

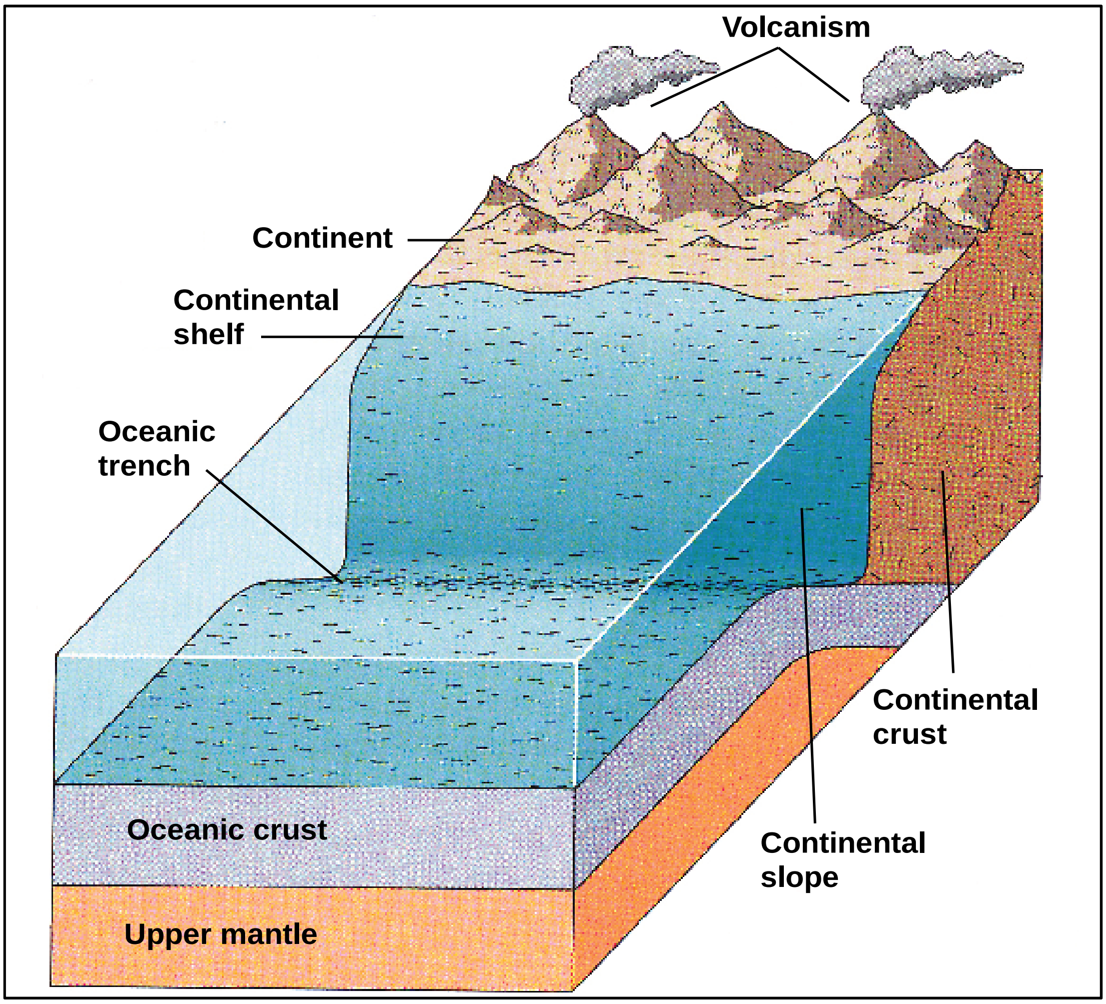

Figure 8: Active Margin (23)

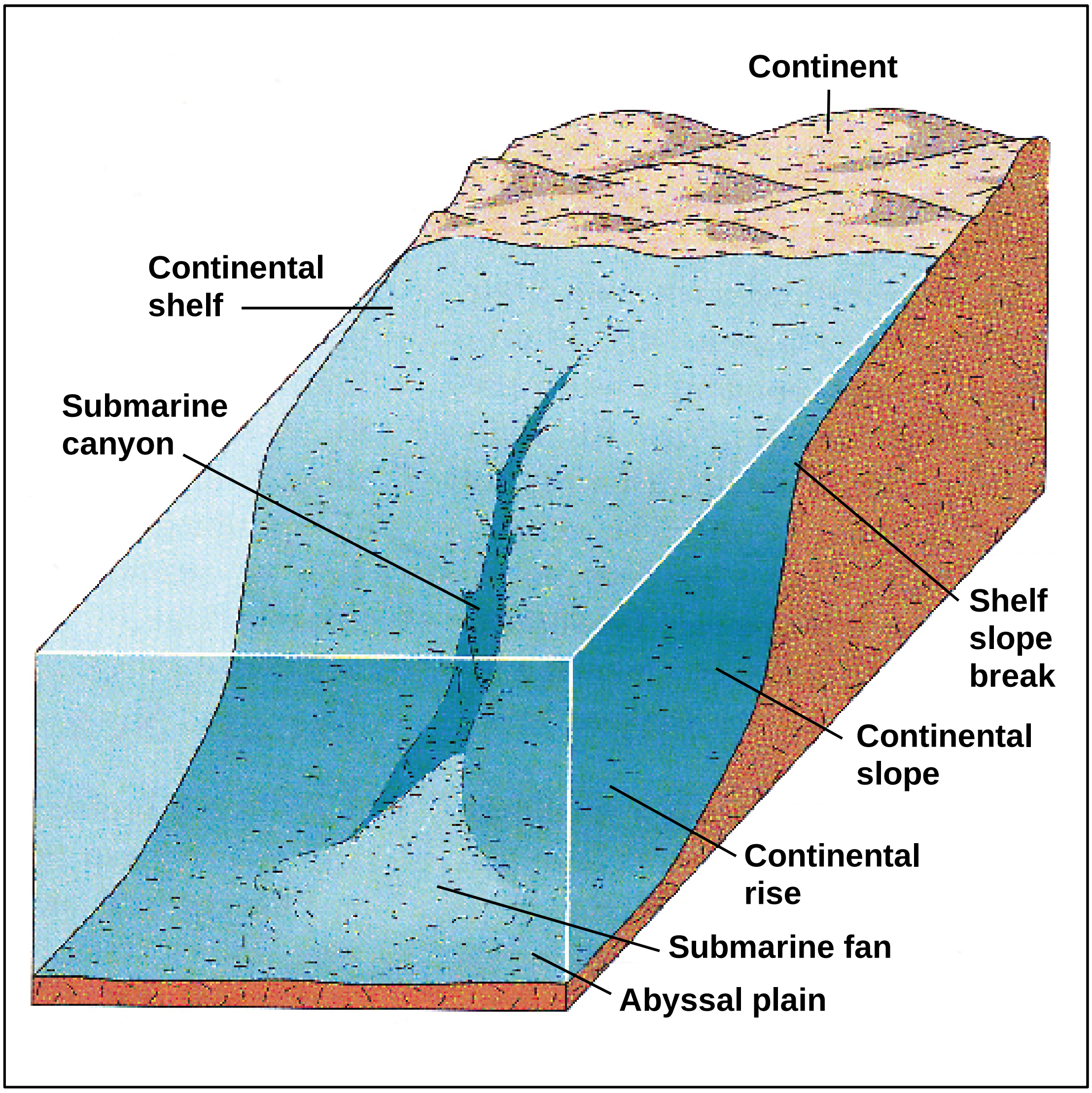

Figure 9: Passive Margin (23)

The oceanic deposits which host hydrates are generally found in submarine alluvial fans that have laid down beds of sand, silt and clay sediment. Over time these have been buried by clays, muds or other mineral layers (Figure 10).

The sediments as laid down are naturally water bearing, and at the pressures and temperatures generally found at about 500 metres water depth, conditions are correct for hydrate formation provided that the sediment is charged with methane and water.

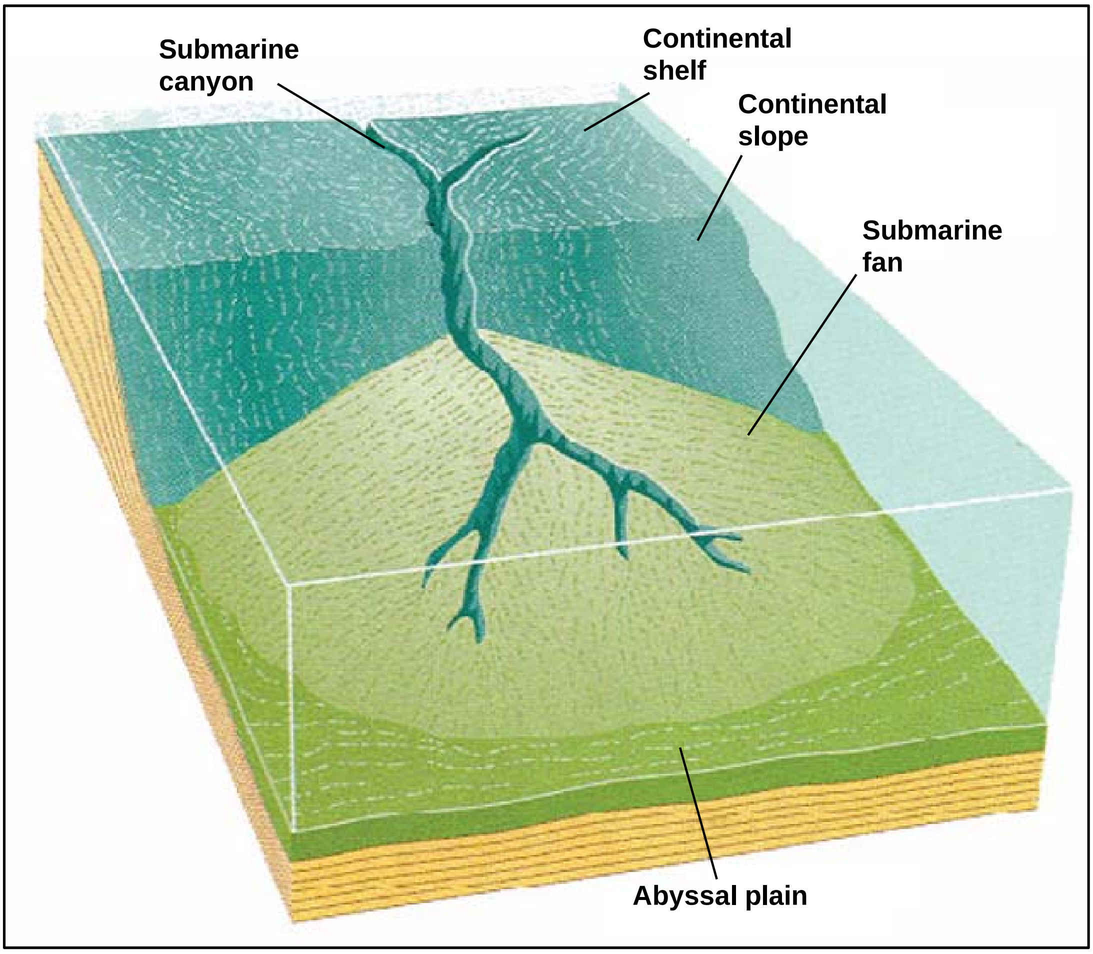

Figure 10: Submarine Alluvial Fan (23)

Much of the seabed deposition is contained within slump structures along the continental margins. The presence of seabed hydrates within these slumps has been noted particularly in the eastern continental margin of North America. Here the slump strata have been mapped in over 200 confirmed locations. The slump locations are not random and it is evident, from a review of the mapped data, that most slides start in a water depth of 500 to 700 metres. It is suggested that over geological time the sea level can fall thus reducing pressure and allowing the gas entrapped by the hydrate to dissociate. Thus causing fluidisation of the sand stone, and therefore, instability of the bed. This in turn can cause subterranean avalanches. The reduction in pressure owing to the fall in sea level will allow the creation from the hydrate of water plus methane gas for each unit of hydrate. This expansion in volume of the pore fluids, because of the reduction in pressure caused by the water level dropping, creates an increase in pore pressure, which can overcome the weight of the sediments that have buried the hydrate zones. This, again, is an activator for sediment slide. The sea level changes, which affect the hydrostatic pressure created by the water, can be induced over time by the formation and melting of ice Sheets formed and dissolved during periods of the Ice Age. In turn these either reduce or increase the volume of water in the oceans of the world. It is possible that the methane gas dissociated from hydrates directly contributed to the climate changes that the Earth has experienced.

It is also possible for methane to become dissociated from the hydrate because of thermal increases as additional sedimentary deposits bury the sandstone, which contains the hydrate. Obviously, this phenomenon of seabed slides caused by the dissociation of methane gas from a hydrate contained within a sandstone sedimentary strata is a major safety and infrastructure risk for potential development options.

Figure 11 depicts a Depth / Temperature plot showing the hydrate stability zone and the thermal gradient decline owing to water depth. It also shows the increasing temperature due to the Earth's geothermal gradient. Both gradients are plotted within the methane gas phase boundary.

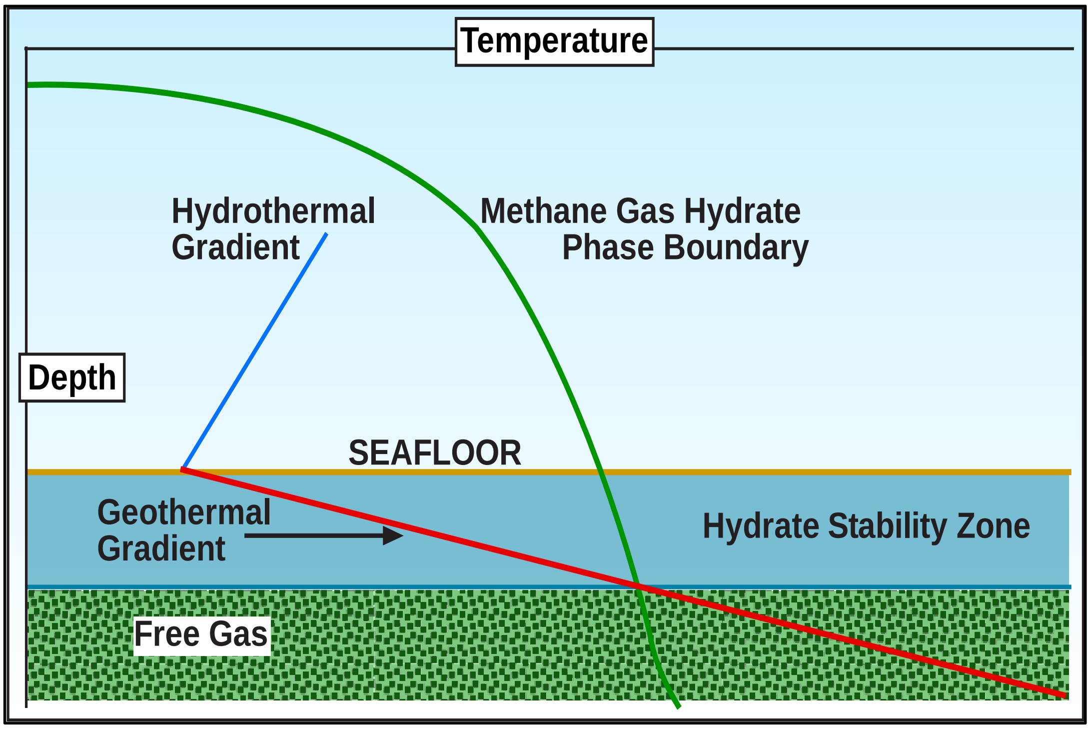

Figure 11: Hydrate Stability Zone (24)

The hydrate stability zone contains the methane hydrate the stability of which is only effective within a defined pressure/temperature regime. In water depths greater than 500 metres, and a temperature up to 14 ^{o}C, the conditions are correct for hydrate formation and stability. It is important to recognise that any sandstone strata below the hydrate stability zone will probably have free gas accumulations, and these are also a potentially attractive source of methane gas production.

The base of the hydrate stability zone is sometimes seen by seismic reflection data as a bottom simulating reflection (BSR). This follows the bottom depth contour at a constant thickness. However, BSR is not always present or detectable in methane hydrate discoveries and, therefore, cannot be used as a natural indicator for hydrate position. One of the major uncertainties associated with gas hydrate production currently, is a lack of geophysical acquisition and interpretation techniques, which can detect the strata of HSZs. They are also unable to quantify their saturation and pore-scale distribution.

2.6 Gas Hydrates and Drilling Operations

The petroleum industry has mixed experience with gas hydrates. Historically, gas hydrates have been a problem when producing water saturated gas, or in well control situations where hydrate accumulations have plugged choke valves, gate valves, choke and kill lines.

Some accidents have occurred with drilling operations which have encountered hydrates. Drilling operations have experienced (whilst drilling in an Arctic Region) mud tank fires after methane gas dissociated from the hydrate owing to an elevation of temperature. The gas subsequently was, inadvertently, ignited. It has also been reported that, within drilling operations in Siberia, uncontrolled releases of gas from Methane Hydrates have occurred on surface when hydrates have dissolved in the mud surface system.

More recently, as the oil industry has extended its frontiers into deepwater locations, there have been some problems where (the well being drilled to a deep strata for the exploration, appraisal or development of oil) has encountered hydrates within the hydrate stability zone. This has led, in some instances to gas cut mud, which has led to low explosive levels (LELs) being reached on surface within the mud system. The solution has been to plug and abandon the relevant hole section and move the well location. Far greater attention is being paid to the shallow gas seismic surveys, and pre-drill bore holes are required more often, so that locations can be selected which do not encounter hydrates.

There is very little experience in commercial offshore drilling operations specifically related to hydrates. The majority of effort being reported are the Scientific Expeditions (25), such as the ODP, and its predecessor the DSDP.

Japan's National Oil Corporation has been reported (12) as leading a two well programme in the Nankai Trough, but very little published information is available.

Within the Arctic region, many wells have been drilled through the permafrost and in some instances, through the HSZ in search of hydrocarbons below the HSZ. Special measures have been taken which could be of use for the deepwater opportunities, the risk being that the gas becomes dissociated from the hydrate accumulations and exposes the land rig to potential explosion and fire. To avoid this, every effort is taken to place the wellhead such that the HSZ is not intersected by the well path. This however either relies on upfront local area knowledge or the use of seismic data to enable a more informed selection of wellhead position.

2.6.1 **Arctic (Land)**

Gas hydrates in the Arctic tundra are almost always below the permafrost layer where the conditions are favourable. Methane gas has accumulated in favourable permeable sandstone that is water saturated, and the conditions are suitable for hydrate formation. Depending on the local conditions hydrates can form at depths up to 2000 metres (17), (26) It is also possible for hydrates in Arctic regions to be detected outwith the HSZ where previously the conditions were favourable. Here some conditions have altered and the gas is dissociating slowly because of thermal conditions.

Detection of hydrates, as explained earlier, can be difficult especially as hydrates and frozen sediments give similar seismic responses. If these hydrates are encountered, an unfavourable gas influx is possible (27).

2.6.2 **Deep Water**

Gas hydrates in deep water drilling, can be encountered depending on temperature, pressure, gas presence and water saturated sediments. Hydrates may be associated with other sub sea geological hazards, such as gas or oil seeps, mud volcanoes, shallow water flows and land slides.

2.6.3 **Geological Threats**

Migrating (thermogenic) gas from a deeper accumulation can be a driving force for the fluids flowing toward the seabed. This can create the correct mechanisms for mud volcanoes, oil flows, seawater flows or gas dissociation; all of which can be hazardous to the people and the environment.

To summarise, key parameters which determine formation and dissociation scenarios are:

- Gas content and composition.
- Elevated pressure.
- Lowered temperature.
- Mechanical properties and their effect on the formation matrix.
- Water.

One unit volume of gas hydrate has approximately 164 unit volumes of methane gas contained within it (28). The fact that this unit volume of gas can be liberated at a shallow depth because of the presence of gas hydrates creates significant potential well control challenges for the Well Engineer. These could be;

- Indeterminate and changing kick volume.
- Gas generation in the mud owing to dissociation from the hydrate cuttings.
- Hydrate deposition in the surface facilities such as shakers, mud tanks, cuttings containment equipment.

It is very important for well engineering that thermodynamic factors are understood, especially aspects like rate of dissociation during drilling or production operations. The properties of hydrate bearing sediments or sandstones still require full investigation and understanding both for well stability issues and seismic calibration.

A fundamental concern for well engineering would be that the well foundations become structurally unstable, either during drilling or production, and cannot be structurally supported by the rock, owing to the dissociation of gas from the hydrate.

2.7 Hydrate Detection

2.7.1 Pre Drill

Drilling Companies rely on shallow gas survey boreholes, or seismic information, to allow safe, accurate planning of wellbore locations. Consequently these are located in an area that will avoid shallow gas, or gas hydrate pockets during the wellbore tophole sections. Thus far, earlier seismic interpretation has not always been effective in identifying gas hydrate accumulations, and much work is still required to calibrate the sonic acoustic feedback with the rock properties of methane gas filled sandstone/sediment. This is particularly difficult, because, as many of the deepsea expeditions have discovered, a core from a given HSZ, when recovered to the vessel being used to conduct the expedition, will immediately dissociate as the temperature or pressure profile is changed. Current work by the Geoscientists has been to improve the techniques for pressurised core recovery that enables analysis of the core to be done with in situ conditions preserved. The industry today is using recognised tried and tested seismic tools such as 3D seismic and the quality of information for Methane Gas Hydrates is limited, when compared to conventional sandstone reservoirs, owing to the lack of suitable rock property/calibration data. This has caused the drilling community to become risk averse, and if any potential risk exists then the wellhead location is moved to try and avoid shallow gas, or gas hydrate zones. An early warning for site surveys is the visual detection of features like “pock-marks” on the seabed, giving clues to previous gas or mud vents through the sedimentary layers.

2.7.2 **Drill**

The primary method for monitoring shallow gas, whether from a gas accumulation or from a methane gas hydrate, is to measure the mud returns for gas content.

Experience whilst drilling, and from the ODP, has highlighted that careful monitoring of drilling parameters may be a good indicator of drilling into an HSZ; as the hydrate zone will be more difficult to drill than water or gas filled sedimentary rocks. This is simply because the strength of the ice-like lattice structure is greater than that of the sediments which do not contain the hydrate.

Pressurized coring can be adopted to core for hydrates under pressurised conditions but this, is of course, provided one has identified the area of concern, and is set up to excavate the pressurised core once HSZ has been detected.

Also, during drilling, it is possible to utilise logging whilst drilling (LWD) tools within the drilling bottom hole assembly to allow resistivity, gamma ray and neutron density parameters to be monitored real time such that an early warning will be given on the presence of methane gas hydrates. This information can be used to take precautionary procedures.

2.7.3 Post Drill

The most common method to detect hydrates is to run wireline logging tools to measure resistivity, gamma ray and neutron density. Calliper logs are also useful because the HSZ will drill up like a hard rock with precision internal bore diameter (when being compared to sedimentary deposits above and below) which gives a good indicator of hydrate presence. One can also deploy wireline tools which take sidewall samples, these can be analysed for the presence of methane gas hydrates. All post drill logging has a higher safety risk than logging whilst drilling because the borehole conditions are such that the gas dissociation process can take place. Liberated gas can start to percolate through the fluid barrier to surface. With gas on surface comes the increased risk of uncontrolled situations which need to be managed by effective well control practices.

2.8 Wellhead Positioning

In deepwater environments where the site survey identifies areas where methane gas hydrates are located near the surface or even visible on the ocean floor, then these sites will not be used. Any temperature elevation, or pressure profile change, owing to the hydrostatic aspects of the fluid column could enable the gas contained within the hydrate accumulation to dissociate. This could then cause fluidisation of the sedimentary beds and lead to collapse, slumping, or cratering of the wellhead location. If a crater is created it could lead to the loss of the entire wellhead structure. More realistically, it could cause some collapse of the soil which will lead to buckling of the conductor casings. Conductor casings rely on support from the surrounding sedimentary beds to help hold upright the heavy wellhead and Blow Out Preventor, (BOP) that are deployed as part of the safe drilling operation. Events, as described above, could cause loss of the well. If not detected early, and acted upon by mitigation measures (well control methods).

2.9 Well Design

Wells that are expected to encounter the HSZ should set some form of casing above the HSZ then, once the HSZ has been drilled, casing should be set, such that the HSZ is contained behind the casing wall. Figure 12 depicts cemented casing to casing and barrier integrity to avoid gas migration.

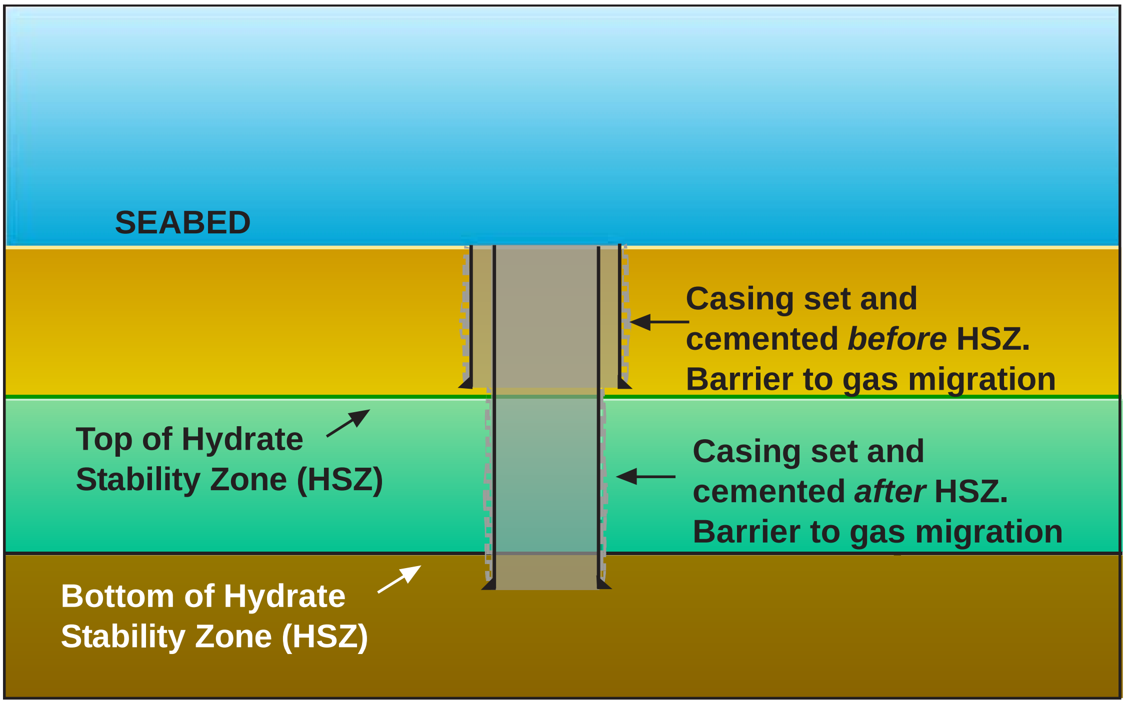

Figure 12: Well Design

Casing set and cemented will preclude the dissociation of gas from the hydrate. But if, dissociation were to happen, then it is likely that the gas will percolate up behind the casing wall and create annular pressures. The cementation bonding of the casing needs to be high quality, and the cement needs to be circulated back to surface to ensure the cement is placed in the well and acts as an effective barrier to gas flow, thus assuring well integrity. This provides maximum pressure protection and will also provide stability for the heavy wellhead and BOP.

Consideration needs to be given in the well design to the annulus pressure that could be generated by the volume changes, if the production process were to cause thermal conditions which created an environment where gas could dissociate from the hydrate accumulation. This could lead to high collapse pressures being exerted on the exterior of the casing if the hydrate formation were to take place when the thermal conditions were to return to geothermal normality. No operational evidence has been found to identify the potential overpressure that could be exerted by this hydrate formation after degradation by temperature, however, an article by Goodman (14) suggests that in normal permafrost wells, collapse pressures of 1.6 x the overburden gradient have been induced by the refreezing of thawed permafrost. It is, therefore, necessary to consider the use of thermal isolators in all casing strings, so that the heat generated by normal production does not get transferred to the sedimentary sandstones which contain the methane gas hydrates.

2.9.1 **Threats During Drilling Operations**

Whilst drilling through HSZs as described earlier, the early warning indicator is gas cut mud returns caused by the gas being liberated from the hydrate lattice structure. The current technology would detect the gas in the mud, and alarms would be activated. These would require safe drilling practices to be adopted, such as; shut in the well, monitor for pressure build-up, then increase the specific gravity of the mud and circulate the well until stable. The dissociation of gas could also lead to cavings coming from the wall of the borehole. These can cause hole fill, stuck pipe or borehole washouts. If not managed with consideration for the prevalent conditions, then the hole will collapse and that hole-section will be lost, often with the drilling bottom hole assembly (BHA) being lost. These events have significant cost implications for the well and mitigation steps must be taken.

Figure 13 shows potential problems by loss of well integrity owing to failed cement barriers, or trapped annular pressure.

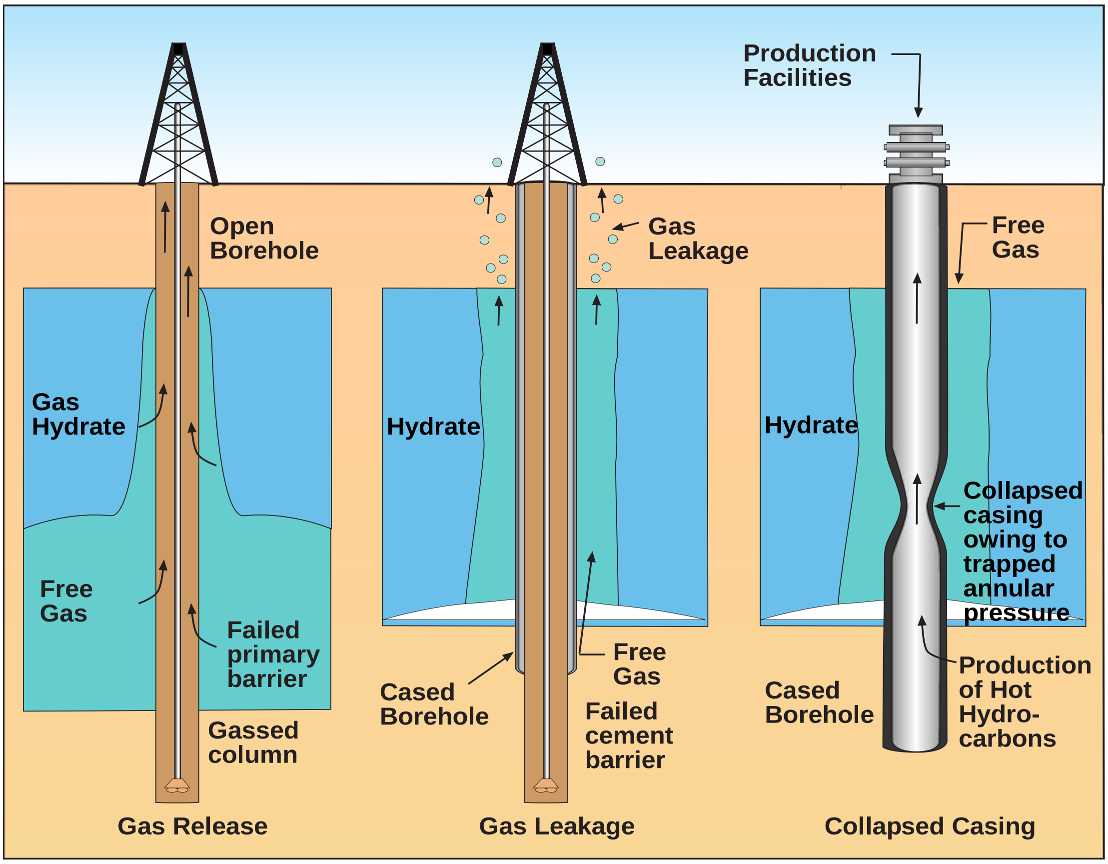

Figure 13: Potential problems during drilling operations and loss of well integrity (9)

Some of the mitigation methods that would need to be considered centre on retaining the HSZ at equilibrium whilst it is drilled. Therfore one must;

- Maintain the borehole temperature at geothermal gradient.
- Maintain the borehole pressure at geopressure gradient.
- Use drilling practises that do not significantly change chemically the near borehole pore contents.
- Use a dissociation inhibitor.

This list is not exhaustive, but for effective hydrate zone drilling it is fundamental to avoid the environmental instability that leads to gas dissociation. The knowledge of how hydrates form can be used as an input for successful drilling practices that prevent dissociation.

2.9.2 **Well Control Considerations.**

As stated previously, gas dissociated from hydrates will enter the wellbore. This gas can be anything from a simple influx that can be managed, to a full scale well control incident that leads to an ultimate blow out.

The industry, in most instances, has adopted as the primary means of well control for hydrocarbon drilling, a fluid system that provides a hydrostatic overbalance when measured against the encountered pore pressure. This methodology has been enhanced by accurate gas detection for the mud system, and by designing drilling circulation systems such that high circulation rates can be achieved to allow gas to be circulated effectively from the wellbore.

Figure 14 depicts pressure increase with depth, the pore pressure being managed in situation by head of drilling fluid specific gravity to retain control of the well.

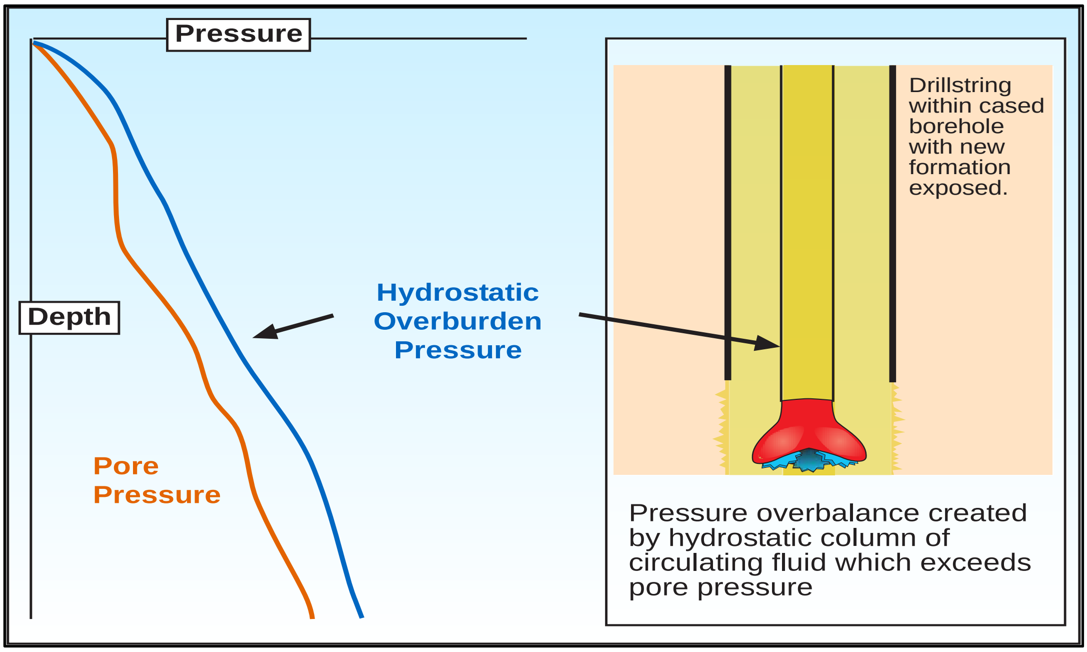

Figure 14: Well Control System (19)

In subsea well operations the secondary means of well control would be BOPs, then dynamically killing any shallow gas influx whilst taking gas returns to the seabed or through a basic diverter type BOP system. Drilling a pilot hole as a detection borehole is a common technique. If shallow gas is encountered it can be dynamically killed much more easily owing to the reduction in volumes associated with the mud circulation system in a smaller diameter borehole. This is a practice recommended in the Shallow Gas Procedures Manual (29).

A review of the Gulf of Mexico R & D Workshop Proceedings (9) (held in August 2000) was undertaken. In particular the work of the Drilling Safety Breakout Syndicate who were tasked with identifying the research required to allow safe drilling through a HSZ in order to gain access to conventional hydrocarbons. The reviewed work on drilling safety was well described and was interestingly very similar to drilling in any new area (frontier) where one needs to succeed safely. The safe practices detailed were:

- Good Well Planning
- Risk Managed Well Execution
- Supporting Offset data

The syndicate session from the GOM R & D Workshop (9) described the items listed in Table 2 as areas where a lack of information existed, which precluded successful accomplishment of drilling through the HSZ.

Table 2: Barriers to Drilling Safety through HSZ.

Well Planning	Well Execution	Lack of Data
• Depth challenge with slimhole. • Geomechanical behaviour of hydrates. • Prediction and detection. • Lack of understanding relationship between gas hydrates and shallow water flows. • Public perception – lack of understanding has created lost opportunities. • High drilling costs.	• Hydrate reformation plugs. • Drilling through in situ hydrates. • Unstable well bore. Emergency disconnection • Kicks and blowouts • Openhole vs riser/BOP well control. • Cementing casing • Maintaining well stability. • Lack of reaction time. • High drilling cost.	• LWD (Logging whilst drilling) shallow. • PWD (Pressure whilst drilling) shallow. • Geophysical data • Petrophysical data • Geochemical and thermodynamic data • Pre drill. • Lack of o Training o Communication o Sharing

Having reviewed the Table 2 contents, and from the engineering challenges described in earlier text it is evident that the existing oilfield methodology will not, as used currently, deliver a technically and economically acceptable solution for drilling into, and production from, methane gas hydrates. Much of the R&D workshop was just debate with no real action to move this initiative forward.

2.10 Literature Research Summary

Conventional well engineering practices will not be suitable for the development drilling of methane gas hydrates with the purpose of production from the hydrate stability zone. The existing convention has been to drill using a hydrostatic column that has a pressure greater than the pore pressure being drilled. This with casing with sufficient mechanical properties will allow the hydrostatic mud column to have its gradient increased to cope with increasing pore pressure as the well is being drilled. This rationale relies on the principle that there is enough mechanical strength to support the hydrostatic pressures being exerted by the mud column and pore pressure such that muds can be circulated around as usual. Methane gas hydrates are encountered at a relative shallow depth in the well, where the sedimentary layers cannot support the casing or mud columns needed to overbalance the pressure induced by the liberated gas. Therefore, new well technology, with revised operating practices, needs to be applied to allow the safe production of methane gas from methane gas hydrates.

The ODP and its predecessor the DSDP has identified that the majority of seabed hydrate systems are found in water depths of over 500 metres and the hydrate stability zones are circa 500 – 2000 metres below the seabed. The challenges faced for the successful economic exploitation of methane gas hydrates are numerous and have been the subject of significant research and development investment over the past two decades.

These challenges, as discussed previously, include:

- Cost (current Oil and Gas well costs are prohibitively expensive).
- Drilling risk (HSE and Operational).

- Well Control aspects post BP Gulf of Mexico disaster
- Seafloor stability.
- Field Development Plans.
- Production and Transportation.
- Environmental issues

The literature available on methane gas hydrates has increased in volume significantly since the start of this research. Some of it made very compelling reading and listed, are examples of the compelling reading in the subject matter area for this research project.

Scientific results from the Mallik 2002 gas hydrate production research well program, Mackenzie Delta, Northwest Territories, Canada (Geological Survey of Canada Bulletin 585) Edited by S.R. Dallimore and T.S. Collett (30).

The Natural Resources Canada and its partners held, as confidential, the publication of bulletin 585 from the Mallik 2002 well program for a period of 4 years, after which time the author obtained a complete copy of the work. The bulletin contains 63 technical research papers and has contributions from almost 300 scientists and engineer involved in the Mallik 2002 Gas Hydrate Production Research Well Program.

Clathrate Hydrates of Natural Gases Third Edition, E Dendy Sloan and Carolyn A. Koh. (31)

This well written third edition book has been incorporated into the Chemical Industry's Series of Reference Books and Textbooks reference number 119. The book provided new fundamental information on structure, kinetics, and production methods, provided computer model software to provide thermodynamic and safety/dissociation times for plug removal

Cruise Report – The Gulf of Mexico Gas hydrate Joint Industry Project (covering the scientific cruise of the Uncle John Mobile, Atwater Valley Blocks, 13/14 and Keathley Canyon Block 151. The cruise was conducted from 17 to 22 May 2005 and the report was published in late 2006. Operational summary Aaron Conte and Ben Bhoys. (13)

This report contained 9 sections of scientific determinations from the offshore operations that lasted some 35 days, and cost almost $8,000,000, with seven boreholes and 5,540 ft of hole drilled or cored during the cruise.

Methane Hydrate Advisory Committee (chairman Dendy Sloan) – Report to the United States of America Congress, dated 15/06/2007 (32).

This report provided insight into the budget and objectives of the US methane gas hydrate programme, as established by the Federal Methane Hydrate Research and Development Act of 2000 and the Methane Hydrate Act as amended by the Energy Policy Act of 2005. The report estimated the resource worldwide to exceed 700,000 Trillion Cubic Feet (TCF) of Natural Gas of which 200,000 TCF are located within the United States.

A TCF is reported in the Shale Gas Primer (33) as being able to:

- Heat 15 million homes for one year
- Generate 100 billion kilowatt-hours of electricity
- Fuel 12 million natural gas fired vehicles for one year

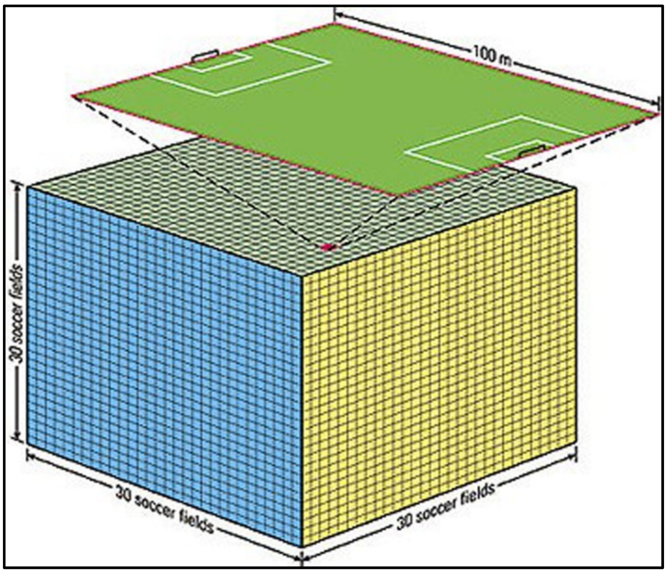

Figure 15: One trillion cubic feet represented by soccer fields (34)

An incredible opportunity for additional energy provided we have the techniques to bring it in an economically viable manner to market. If the low-end number of 700,000 TCF were to be substantiated, then we will be energy rich for over another 100 years.

South Korean National Methane Gas Hydrate Drilling Expedition program in the Ulleung Basin, East Sea by Keun-Pil Park (KGHDO) and the UBGH - 1 scientific party March 2008. (35)

The Ulleung basin gas hydrate expedition 1 (UBGH1) successfully explored and recovered gas hydrate cores from three locations, during a 57 day, two-leg expedition and confirmed presence of gas hydrates in all three locations.

Gulf of Mexico Gas Hydrate Joint Industry project leg II: Operational Summary of April 2009 Hydrate drilling programme (36).

The Gulf of Mexico Joint Industry project successfully drilled and collected a suite of downhole logs from seven exploratory hydrate wells in water depths greater than 750m. Hydrate wells approximately 750m long were drilled using a semi-submersible vessel.

The above examples provide a summary of the most useful references reviewed during the past five years of this project.

3 Exploitation Strategy Considerations

3.1 Strategy for Exploitation

Reviewing the conventional methods for deepwater development drilling has confirmed that the traditional well is split, almost evenly, between drilling and completion, and that only 50% of the drilling time is made up of actual drilling. The rest could be considered waste as, it is only an enabler for delivery of a borehole through the hydrocarbon horizon. Once through the hydrocarbon horizon the other 50% of the time was spent making the well safe and secure for hydrocarbon production by the installation of a completion. The need is to move away from the traditions as described to a place where we can as efficiently as possible drill to total depth (TD) and do as little as possible thereafter, before turning the well over to production. What is required is a well that is drilled, cased, completed and ready for production within 10 days. This would represent a tenfold improvement when compared to these current operations.

A review of existing data (37) demonstrates the ability to drill to equivalent depths as required in about five days which without any drilling inefficiencies leaves five days to prepare the well for production.

3.1.1 What type of well is needed.

A well is required that can intersect the HSZ indirectly, such that the stability of the structure is not jeopardised by the drilling, or production operation. It is, therefore, proposed that a horizontal well be drilled. The horizontal or high angle well will provide a much greater radial flow area and will avoid localised stability problems above the HSZ.

The well would have to have functional elements, namely:

- Barrier to flow.
- Horizontal bore to entend area of radial flow.
- Can dissociate gas from hydrate.
- Sand control method.
- Hydrate removal from wellbore.
- Simple.
- Low cost.
- Can be drilled and completed in 10 days.

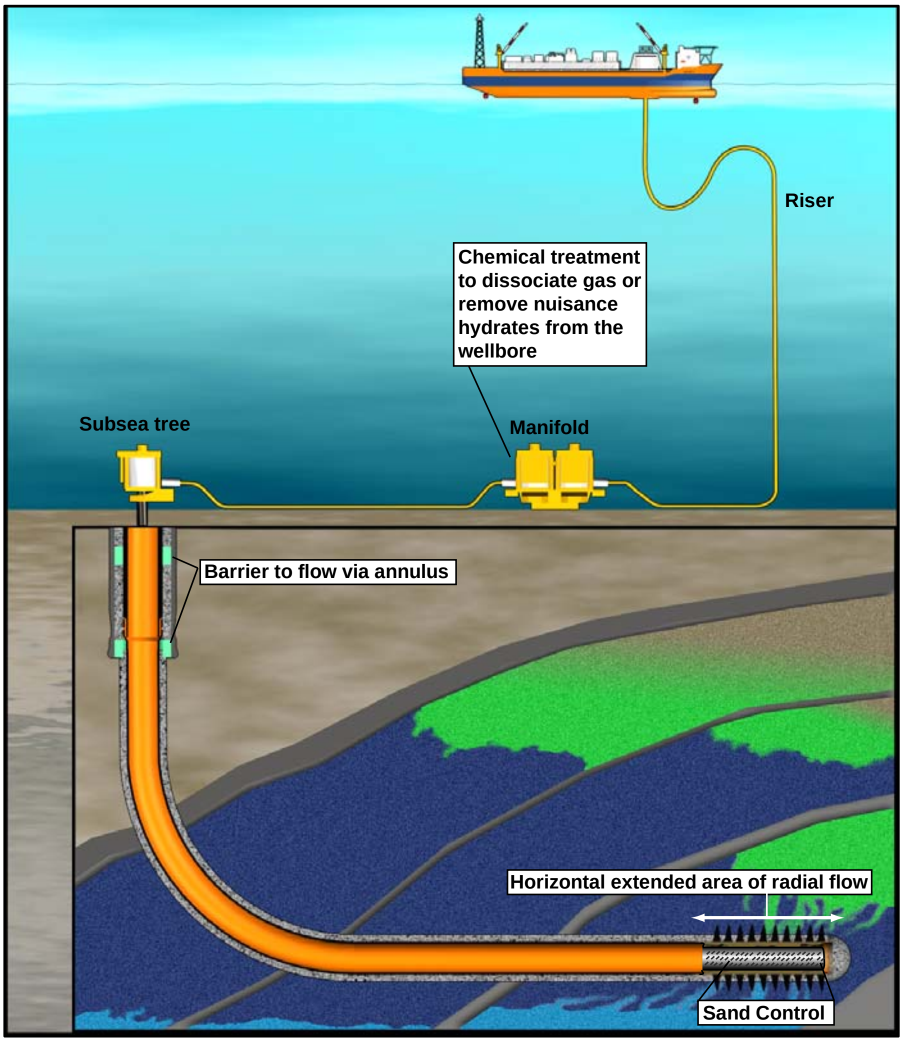

Figure 16: Well Type Requirements (19)

3.2 Conceptual Well Engineering – Concept Overview

It is intended to utilise new, or existing technology, to slimhole drill the wells. Tophole will be drilled as a 6 3/4" hole utilising a 4 1/8" drill bit with a 6 3/4" underreamer. Surface casing will be 5 ½" 14 lb per foot, with optional hole angle build, depending on final outstep required. The section will be drilled with low density brine (i.e. Sodium Chloride) and hole cleaning chemical sweeps to remove cuttings from the hole. The section will be drilled utilising, casing whilst drilling technique with Blow Out Preventor control. To aid this, good seismic data will be needed to give confidence that shallow gas does not exist and a site, survey combined with a pilot drill hole, will have been conducted before arrival of the development vessel. The surface casing will be cemented back to the seabed to ensure a suitable foundation for the wellhead and production equipment.

The Hydrate reservoir will be drilled as a 4 1/4" hole, utilising a 2 7/8" drill bit with a 4 1/4" underreamer. Well casing and tubing will be 3 ½” 9.2 lb per foot with hole angle building to a very high angle or horizontal, depending on well requirements. The reservoir section will be drilled utilising casing whilst drilling techniques, combined with, a sub sea topdrive package with a pressure control module. The 3 ½" Tubing will have a packer or seal assembly within the string to provide an annulus pressure barrier. The lower completion, below the packer, in the open hole section will provide means of dissociating the methane from the hydrate by depressurisation. The lower completion will provide sand control using sand screens to preclude production of large quantities of sand through the sub sea facilities.

The drilling system and subsea topdrive will drill on a batched grid pattern with a high density well concentration per hectare of seabed. This provides operational efficiencies for movement of the drilling on a well by well basis.

The well would be drilled with a Measurement Whilst Drilling (MWD) and Logging Whilst Drilling (LWD) devices, to gather scientific data, as part of the bottom hole assembly.

The casing drilling system would be used, and it is intended to use both the sub sea top-drive system and the drilling motor assembly within the casing drilling BHA. This will provide increased penetration rates and improved hole cleaning as the pipe rotates. An advantage of the Sub sea top-drive is that it allows the removal of traditional riser systems that are deployed from the vessel as the drilling system is located on the sea floor. By removal of the riser system, there is no hard connection between the vessel and the well. This makes the operation less susceptible to weather down time and avoids the time required for riser deployment. The vessel can also sail away easily if unsafe conditions were to materialise in the drilling process.

3.2.1 **Modelling 6 ¾" Top Hole with 5 ½" Casing.**

As detailed in the well schematic (Figure 17) the tophole will be drilled as a 6 3/4" hole utilising a 4 1/8" drill bit with a 6 3/4" underreamer. Well surface casing will be 5 ½" 14 lb per foot with optional hole angle build depending on final outstep required. Bi Centre bits are being used more and more in the oilfield, to open holes to a diameter greater than the internal diameter of passage, but, in casing drilling applications, this relationship between hole size drilled and casing internal diameter, has not been readily achievable.

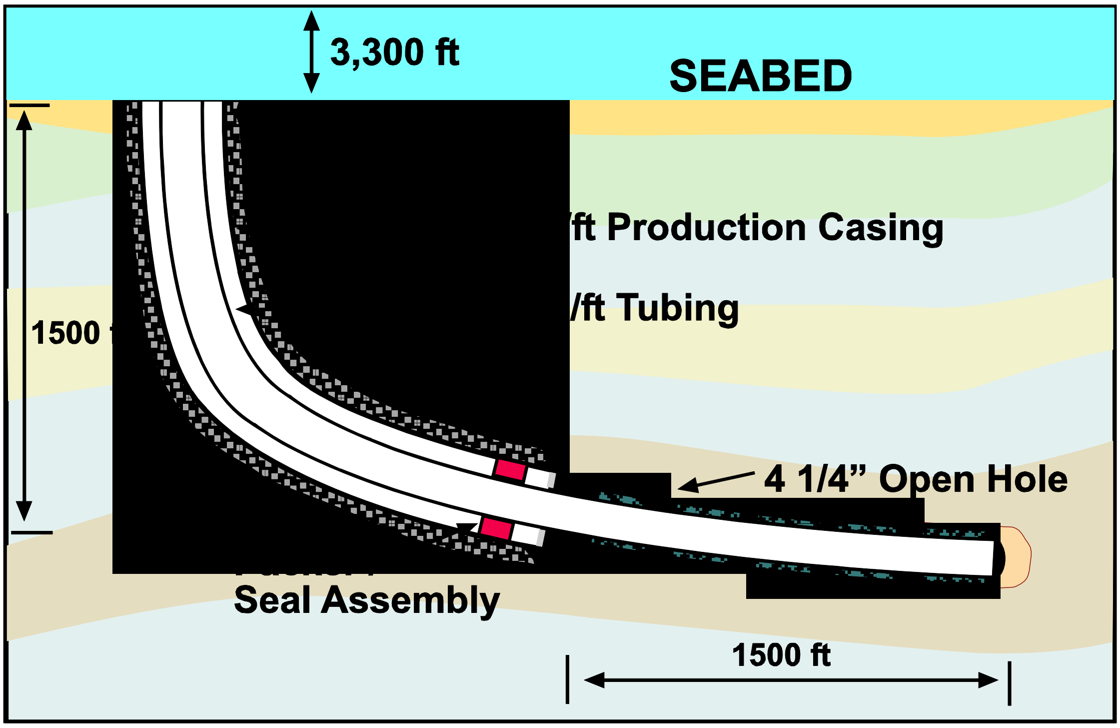

Figure 17: Wellbore Schematic (38)

Directional control is possible by utilising an MWD sub within the drilling BHA and by using powerdrive, or bent subs, to allow directional positioning of hole, both for inclination and azimuth control. For both hole sections logging can be achieved by the use of a Logging Whilst Drilling (LWD) sub.

Well modelling has shown that the hole section can be drilled within safe operating parameters namely.

- Torque
- Drag
- Deviation
- Casing Tripping weight
- Buckling

Depicted in Figure 18 and Figure 19 are two screen dumps from a well model utilising Wellplan software. The full run details are included in appendix 1.

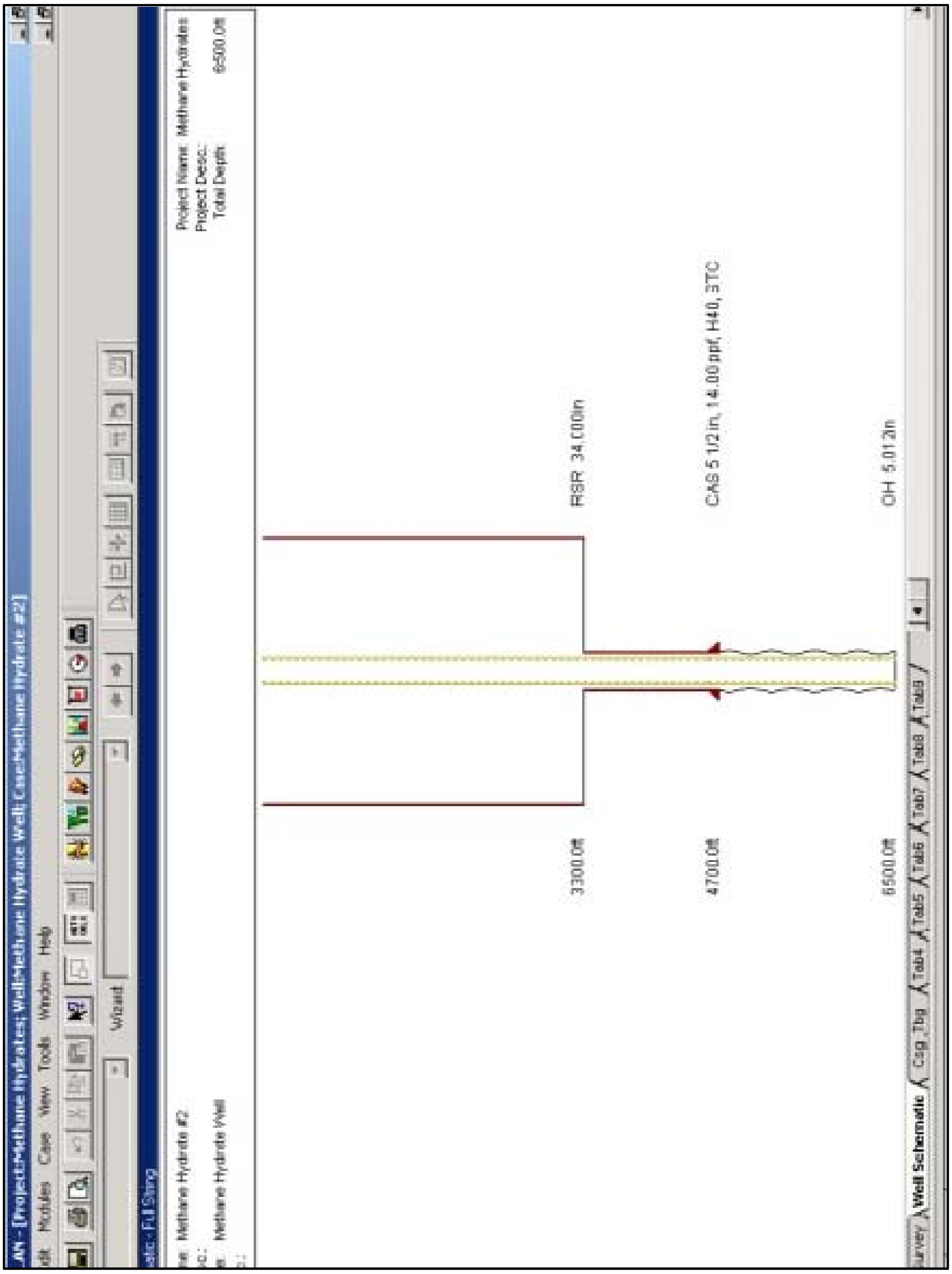

Figure 18: Full String Chart

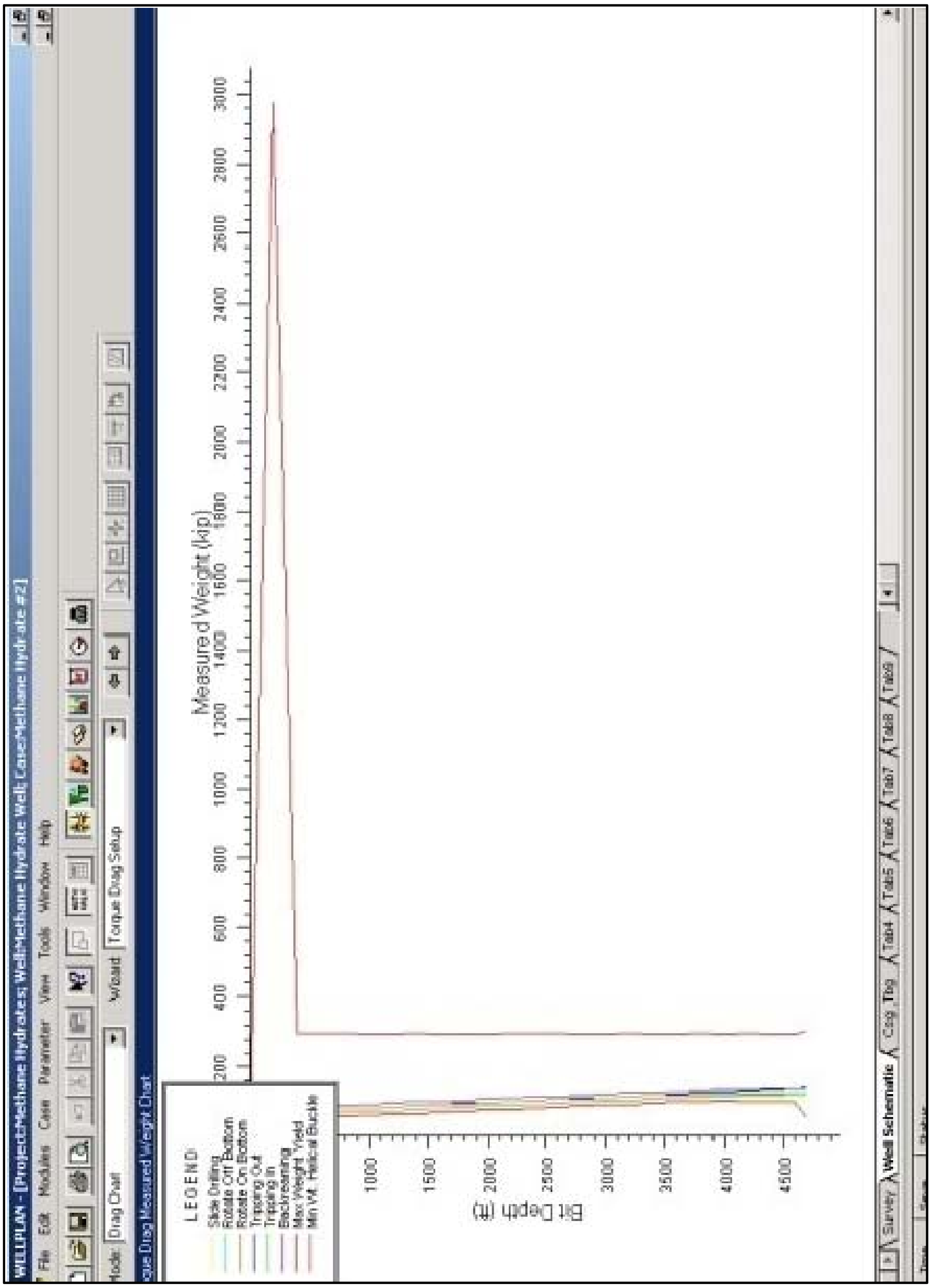

Figure 19: Drag Chart

Well-cat Casing Design software tool was run to clarify that the well design as proposed met that requirements for

- Burst (Safety factor 1.25)
- Collapse (Safety factor 1.0)
- Axial (Safety factor 1.3)
- Tri-axial (Safety factor 1.25)

These safety factors are applied to compensate for casing wear, casing imperfections in manufacture and casing diameter tolerances range

The modelling detailed confirmed the required surface casing suitable for this intended service and modelling outputs were within current oilfield safety factors.

3.2.2 Modelling 4 ¼" Reservoir Section with 3 ½" Tubing

Reservoir will be drilled as a 4 1/4" hole utilising a 2 7/8" drill bit and the hole will be opened out with a 4 1/4" underreamer. Directional control is possible by monitoring deviation data with an MWD sub within the drilling BHA. Directional and azimuth control can be achieved with either a bent sub or by using an automated steering system. The tubing will be 3 ½" 9.2 pounds per foot tubing.

Well modelling has shown that the hole section can be drilled within safe operating parameters namely:

- Torque
- Drag
- Deviation
- Tubing Tripping weight
- Buckling

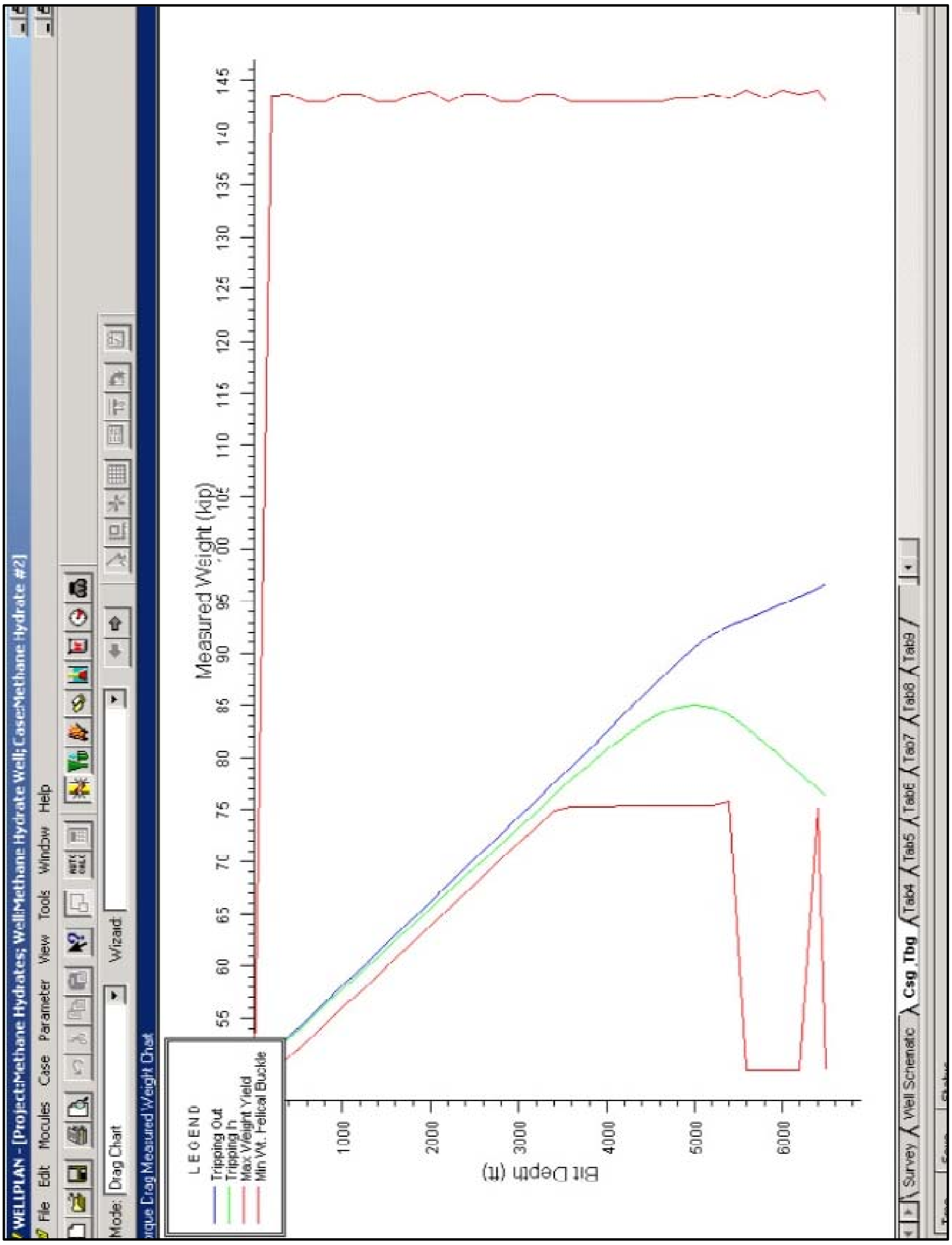

Figure 20: Drag Chart

Depicted in Figure 20 is a screen dump from a Wellplan software model depicting drag loads that was run for the well, the full run details are included in appendix 1.

Well-cat Tubing Design software tool was run to clarify that the well design, as proposed, met that requirements for:

- Burst (Safety factor 1.25)
- Collapse (Safety factor 1.0)
- Axial (Safety factor 1.3)
- Tri-axial (Safety factor 1.25)

The modelling has confirmed the preliminary design suitable for the intended service. A point of note is depicted in Figure 21 below. The modelled axial loads are acceptable, however when compared with the absolute axial safety factor of 1.25, it can be seen from the depiction that the conditions for methane production, hot kill and hot shut-in bring the modelled load conditions close to the acceptable criteria at, or around, 4,500 ft.

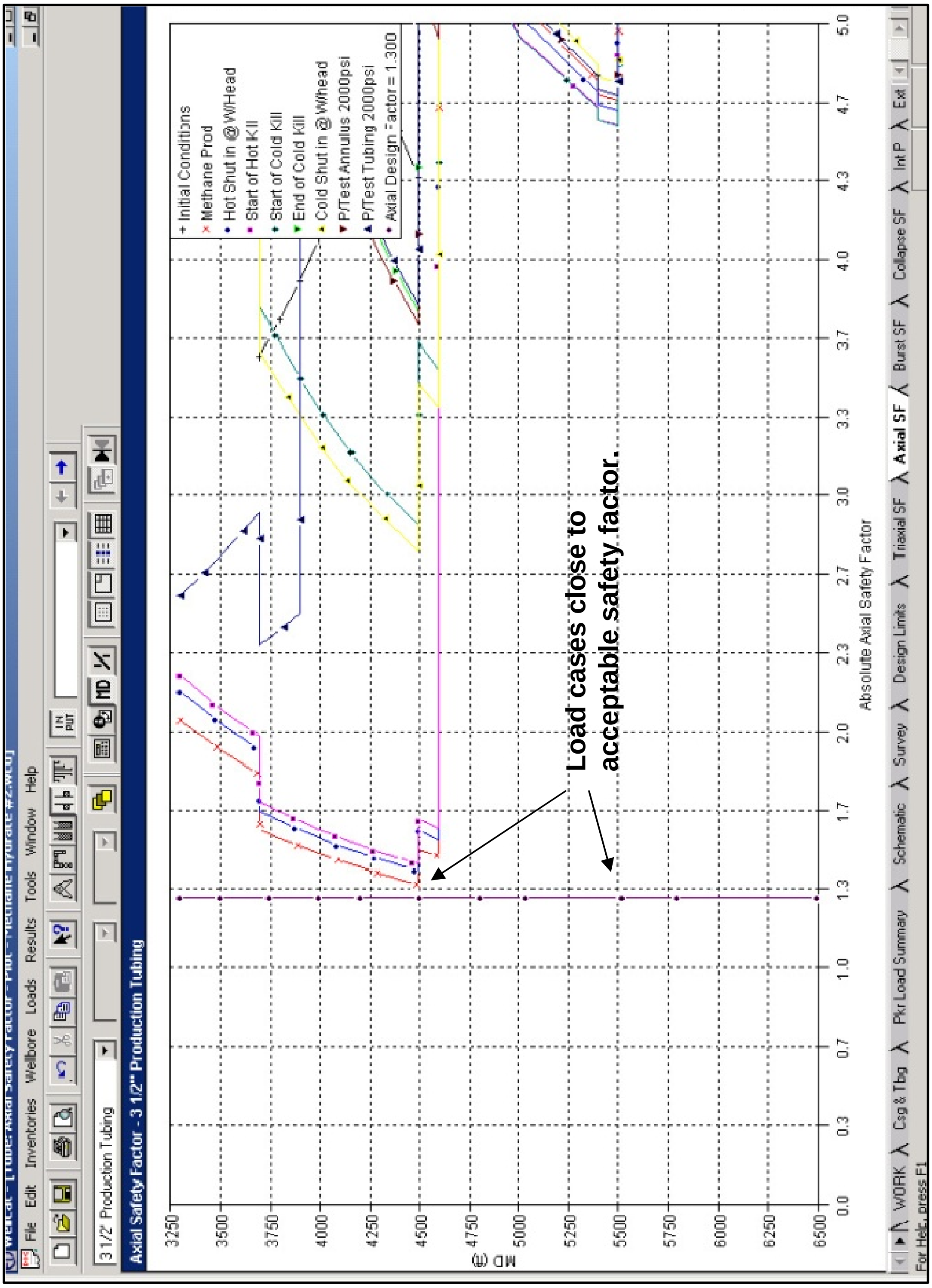

Figure 21: Axial Safety Factor

The above figure depicts well life load conditions that are close to the acceptable safety factor.

3.2.3 **Casing Drilling-What is it?**

Casing drilling is a new technology currently being developed and trialled by several operators in the oil and gas industry. The casing is used as the drill string and has within it, a bottom hole drilling assembly, which can be recovered when section total depth (TD) has been reached. The method is fast and efficient and avoids the time consuming practise of drilling with drill pipe then recovery of the drill pipe then conveyance of the casing string.

Benefit Summary

Drilled and cased off simultaneously avoiding much of the hole problems from elements, such as reactive shales and unstable hole conditions.

Advantages

- Reduces unscheduled events and flat times.
- Reduced overall well costs (10-30%).
- Elimination of drill pipe and drill collars.
- Elimination of tubular tripping.
- Casing can be cemented, with the bottom hole assembly in situ.
- Increased safety (loss of hole, tubing handling reduction.)
- Improved HS&E (reduced handling).

3.2.4 **Casing Drill - Details of System**

The casing drilling system is made up of down hole and subsea components that allow the use of standard casing joints, as a drill string, providing both mechanical and hydraulic power, to a wireline retrievable drilling assembly. The wireline retrievable drilling assembly is suspended in a landing nipple, at, or near, the casing shoe. The casing can be rotated from the surface to drill the well or the casing internal bore is the pathway for hydraulic power to the motor, so that the casing can remain static, and the hole section drilled using the motor assembly.

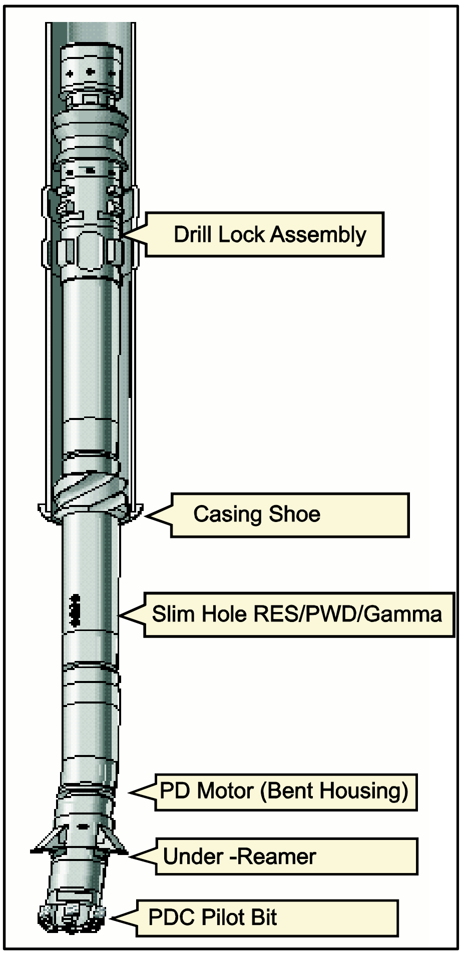

Figure 22: Casing Drilling (19)

The drill lock assembly (DLA) in the upper part of the BHA provides mechanical coupling to the casing, and also provides the means of sealing the casing to BHA, so that the hydraulic fluid can be delivered to the motor assembly and the drill bit.

The DLA has a locator and lock mechanism very similar to most wireline retrievable devices used in completion designs today. With a seal bore and seal stack, it is very similar to a wireline lock mandrel. The key difference, however, is the splined mechanism that locates within the landing nipple, to provide the means of delivering torsional forces.

The PDC bit, depicted in Figure 22, is run with an underreamer above such, that the PDC bit drills basically a pilot hole then the underreamer opens the hole out to the size suitable for the casing running.

The casing drilling system uses either the motor within the drilling bottom hole assembly, or a top drive, to rotate the casing.

3.2.5 **Subsea Topdrive System**

The casing string will be attached to the subsea topdrive utilising an internal casing drive system, that has been developed by companies such as oil services company, Tesco.Inc. The system provided by Tesco has a slip assembly that is held within an overshot type device, thus gripping the exterior of the casing with an internal spear which provides a hydraulic seal for the pipe.

Figure 23 is representative of an umbilical operated subsea topdrive system which could be deployed from a dynamically positioned vessel.

Figure 23: Diagram depicting a representation of a subsea topdrive system (19)

For this application the BHA and Casing, would then be conveyed, complete with sub sea topdrive system to the seabed using wireline from the support vessel crane. The system would land and locate in the mudline system (38) as shown in Figure 24 and drill itself into position. The proposed mudline suspension system is a new patent pending, IP, designed by the author. It is described in detail in Section 4. The BHA has a powerdrive, or similar device, which allows angle to be built, whilst drilling the section, to allow the casing length to be drilled into position with a 45 deg inclination. The drilling cuttings will be recovered to the seabed and the mudline system will have the facility built into it to direct the cuttings to re-injection wells or cuttings recovery.

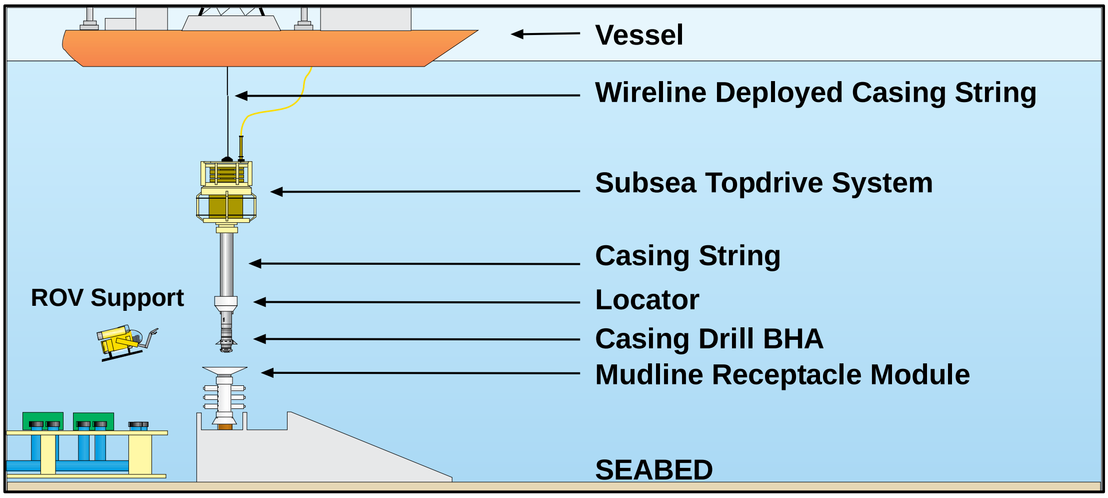

Figure 24: Deploying Surface Casing (38)

Once the casing is at the required depth, the sub sea topdrive system will be ported open at the top of the unit, and wireline deployed to recover the drilling BHA. Once the BHA has been recovered from the landing nipple profile, the casing will be cemented via the sub sea topdrive, with returns back to seabed. It would be possible to install cement into the cement column by hydraulic manipulation of the sub sea topdrive system so that the plugs could be deployed as a part of the cementation process. This would, however, add complications and trials would need to be conducted to assess the suitability of the cementation, if the cement were circulated into place behind the casing wall without cement plugs acting as a barrier to the circulating medium. Once the cementation is completed, the sub sea topdrive can be recovered on wireline from this mudline receptacle slot. At surface an identical system will be already made up to a second casing string, which will now be deployed on an adjacent mudline well bay. In theory we could have two simultaneous drilling operations provided sufficient deck space being available for all the surface and subsurface equipment. It may be that a supply boat could be used to provide additional deck space for enhancement of logistical capacity. It is not envisaged that simultaneous drilling systems would be utilised initially, but this is seen as an opportunity for improvement of performance, once operational experience had been built up.

3.2.6 **Drilling Horizontal or High Angle into the Hydrate Stability Zone.**

Casing whilst drilling will be used to drill the HSZ. To do this a 3 1/2" flushjoint casing string will be used, combined with a 2 7/8" drill bit and bottom hole assembly components, namely a mud motor assembly, complete with powerdrive to allow the hole to be drilled expediently. An under-reamer will be used behind the drill bit to open the hole to 4 1/4". Currently, the measurement whist drilling, and logging whilst drilling, tools require a fluid environment to operate, and hole sweeps will be required to obtain accurate data. This is an area for further development and directional and logging data recovery, in a gaseous environment, would be a key area for further study. Whilst drilling this hole section, it is important to avoid practices which may liberate methane gas from the HSZ.

Underbalanced drilling is defined as drilling with the hydrostatic head of the drilling fluid, intentionally designed to be lower than the pressure of the formations being drilled. Underbalanced drilling is not recommended in this instance, due to the possibility of releasing methane gas from the well bore.

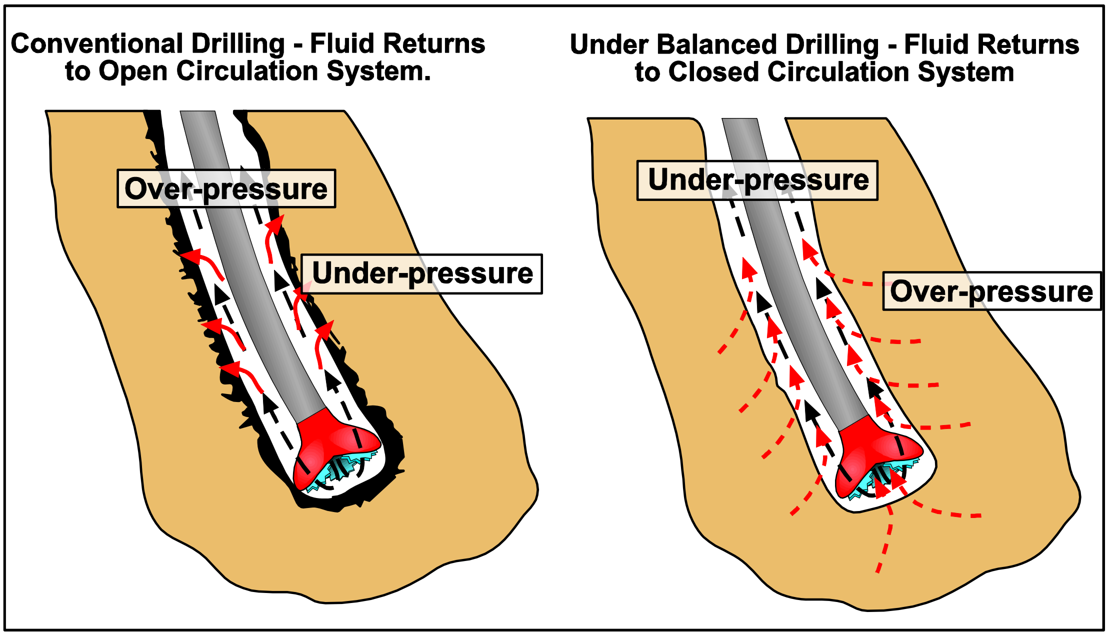

Figure 25: Underbalance and Overbalance Theory (19)

Conventionally when drilling overbalanced; a hydrostatic fluid is used to maintain the wellbore pressure, acting as a safeguard from any influx of formation fluids or gases. This would have to be the case with hydrate zone drilling, and new legislation covering all types of offshore drilling will demand this.

Design Summary

To drill into the hydrate stability zone our casing whilst drilling sub sea topdrive system will be mounted on a pressure control module which will be connected to the 5 1/2" casing wellhead system and have the ability to close in on the 3 1/2" casing with an annular preventor. The pipe’s internal pressure will be controlled by the sub sea topdrive system and the return pressures will be controlled by a choke system located on the pressure control module. The drilling cuttings will be routed to a disposal well or system, having first passed through a subsea centrifuge system ensuring the associated hydrocarbons, or solids, in the fluid are reduced to acceptable levels for discharge. This same centrifuge system will be used to remove produced water and sediments from the gas stream, when the well is on production. Drilling and leaving in situation the 3 ½” tubing with sand control and packers will require extensive field trials to perfect the techniques. If well control problems occur, the well can be dynamically killed with seawater, as if it were shallow gas. It is envisaged, however, that the gas and water would react to form hydrate plugs which would seal the wellbore, and this is the best defence for well control.

3.2.7 Hydraulics and Hole Cleaning

The importance of hole cleaning during the drilling of both the hole sections cannot be over-emphasised. The casing drilling, if not combined with rotation by the sub sea topdrive system, will lead to formation of cutting beds or accumulations on the low side of the hole. This has been demonstrated many times in coiled tubing drilling operations where the coil has become stuck, expensively, because of the build up of cutting beds. Cutting beds when formed require both rotation and agitation to breakdown, and the agitation normally comes from clean-out trips. The benefit of cased hole drilling is getting the casing in place whilst drilling up the section. Therefore operating practice must include both drilling and frequent rotation to provide best possible hole cleaning conditions. Experience has shown that good hole cleaning can be achieved in coiled tubing drilling, by combining low viscosity and high viscosity circulation sweeps; one circulation sweep to start the cuttings moving and the other to keep them in suspension during transportation to surface. The casing drilling, that it is planned, will benefit from occasional application of this type of combination sweeps. When setting the cutting lift velocity, the balance of effective hole cleaning versus prevention of hole wash out must be understood and managed to avoid drilling difficulty.

3.2.8 **Drilling Considerations**

It is important for the safe and efficient drilling of the reservoir section, that methane gas is not liberated during the drilling of the HSZ. It is planned therefore to use a combination of brine, with viscous sweeps, to aid hole cleaning. The use of brine has two advantages. It is inert, when in contact with the hydrate, which therefore will help avoid the reactive problems associated with drilling into the hydrate stability zone. It is also very easily mixed on board the Dynamically Positioned Vessel (DPV).

The return materials from the circulation system will be diverted, as in the previous hole sections, to a disposal system away from the modular equipment, via the sub sea centrifuge system. If gas is present this will be monitored by gas detection at the pressure control module and small quantities will be vented to the sea. This is to avoid the significant risk associated with gas being recovered to the boat for venting or flaring. It would require a Hazard Assessment to be satisfied that the method for gas venting sub sea was non hazardous to the facility, or the vessel. To avoid hydrate reforming methanol, or glycol injection will be possible via the umbilical. This would be injected in upstream of the choke. The methanol will also be able to be pumped back into the annulus of the well, if necessary, to allow hydrate dispersal.

Penetration rates are such that the hole can be drilled to TD within 24 hours with penetration rates of circa 30 - 100 m (100 - 300 ft) per hour (36) expected, as the normal penetration rates. It is important that this section is drilled in as expedient a manner as possible as it provides fewer opportunities for the methane gas to dissociate from the hydrates, which could lead to further problems with the drilling operation.

Table 3 shows the overall rates of penetration achieved during the recent (2009) GOM JIP Leg II, where the primary purpose was the collection of a range of logging-whilst-drilling data on typical hydrate reservoir sands. Based on standard industry experience, it is expected that these rates would be doubled during a typical commercial drilling programme.

Table 3: Penetration Rates achieved during LWD data collection(36)

Well	Length Drilled (m)	Time (hr)	Penetration rate (m/hr)
WR313-G	776	42	18.5
GC995-I	650	12	54
GC955-H	585	13	45
GC955-Q	441	12	36

3.2.9 Completion Integrity

At TD, after hole cleaning efforts, the packer assembly is set inside the 5-1/2" casing to form a seal, and thus secure the annulus of the inner casing string from any gas migration behind the annulus. Before the packer was set, the annulus should be displaced to a glycol / water mix, to avoid potential collapse problems associated with hydrate formation when the wells are closed in. This is a valuable barrier which gives protection against potential tubing collapse.

The BHA will probably not be recovered, as the cost and time associated with rigging up intervention equipment is deemed to be prohibitively expensive. Although the BHA will cost around £200,000, it is seen that this is the lower cost option.

Material corrosion properties of the BHA are therefore important to minimise any impact on the well or the environment.

3.3 Production

3.3.1 The 3 ½” Tubing

The 3 ½” tubing needs to be designed capable for casing whilst drilling operations then also provide:

- **Pressure Transmission**; to be able to prevent pressure transmission through the body of the casing to the well bore during installation, but allow product to flow through it once the well is in production.

- **Sand Control**; act as a sand filter to prevent the potential large amounts of sediment from being back produced with the wet gas. It is important to recognise that the well will be producing wet gas and associated sedimentary deposits, therefore to enhance stability of the overburden, and to prevent costly erosion of our infrastructure, the well needs to have a means of controlling, or preventing sand production.

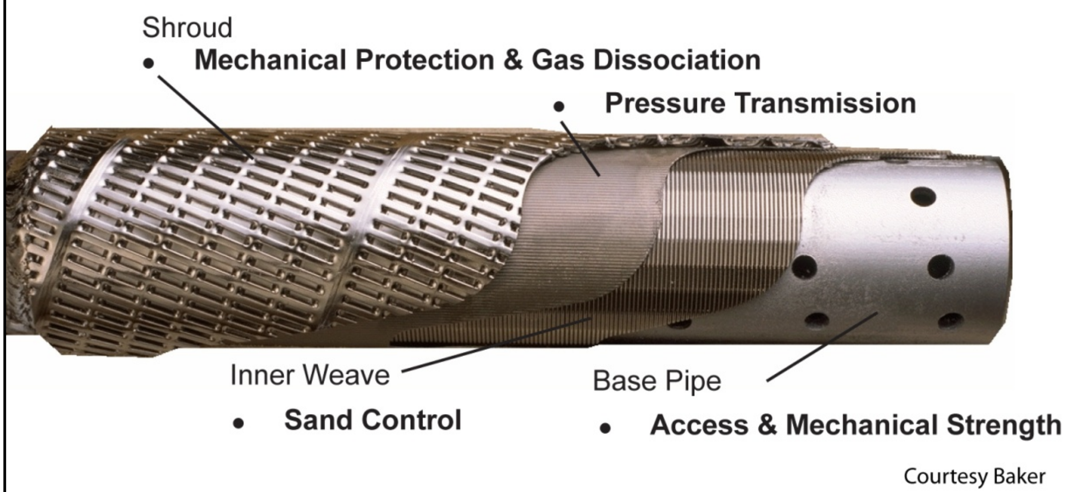

Figure 26: 3-1/2" Tubing Design Features (38)

Sand control will be a requirement as it is envisaged that the relatively unconsolidated sediments will break down into a slurified soup-like mix that could lead to screen partial blockage, as the poorly sorted particles contact the screen weave (Figure 27). When sizing the sand control screen it will be important to trade off sand control down hole with the knock out of sediments by the sub sea centrifuge system. Steps to be taken to ensure correct selection will include:

- Perform fully integrated study.
- Include experts and peers in the evaluation process.
- Use rigor in decision analysis (include performance and cost risk / uncertainty).
- Have a carefully considered well unloading, bean up and monitoring plan in place.
- Get production test on well after it is on production.

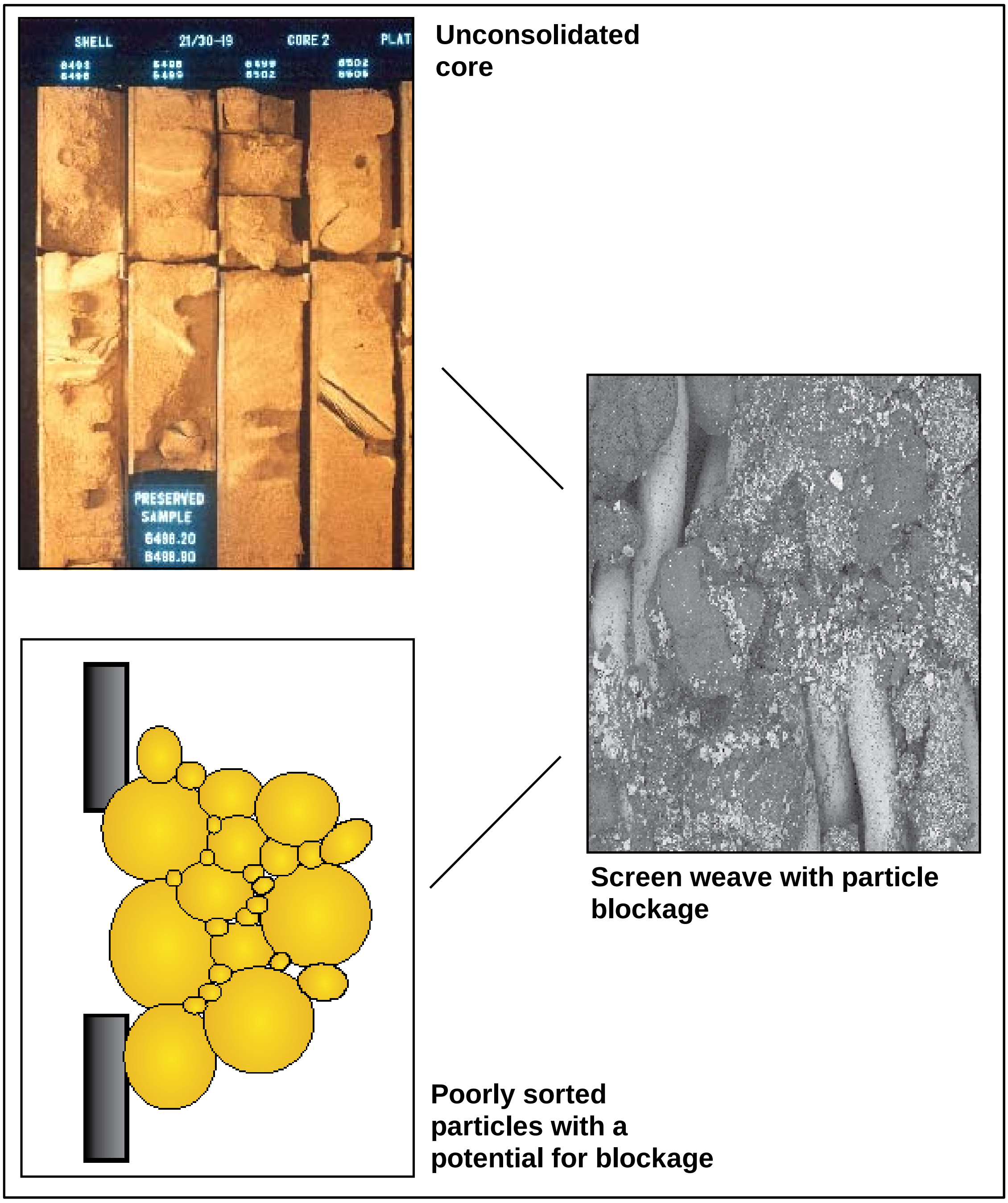

Figure 27: Sand Control Challenges (19)

3.4 Pressure Barrier for Safe Well Entry

For exit from the well, or re-entry to the well, a barrier which can be operated will be needed to allow recovery of the sub sea topdrive system and pressure control module. This can be achieved, simply, with today's technology, by the use of a sub sea lubricator valve, which is hydraulically operated open or closed by hydraulics available within the umbilical system. Having drilled the hydrocarbon bearing section and requiring safe exit from the well, closure of the lubricator valve and leak off test will provide adequate protection. Once integrity is confirmed, then the pressure control module and sub sea topdrive system can be unlatched to allow recovery or transfer to another well-slot, depending on the drilling sequence programme.

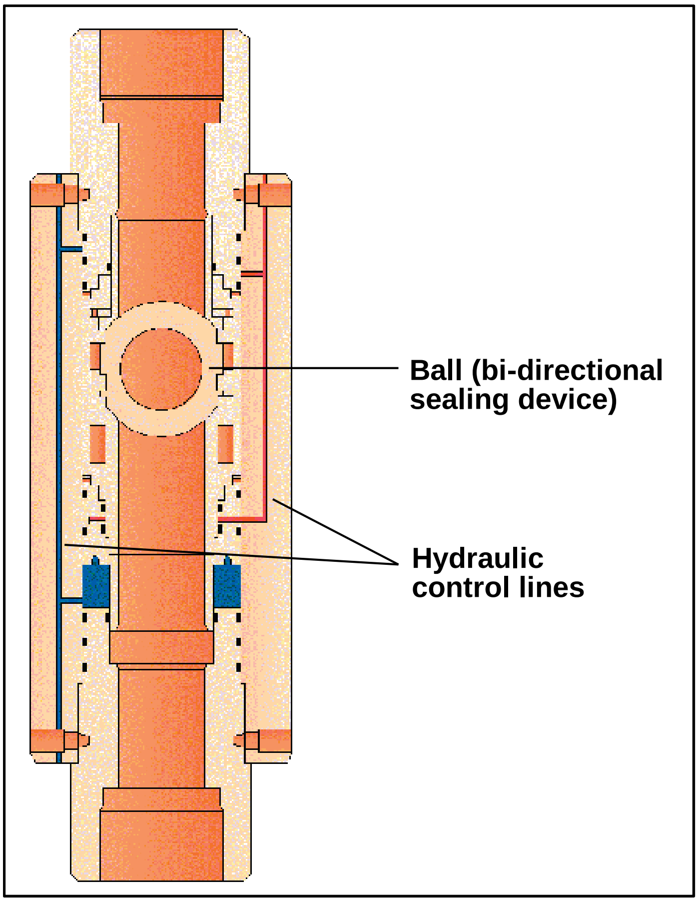

Figure 28: Subsea Lubricator Valve (courtesy Expro)

In summary, the well is completed with two strings. Casing support string and completion string. There is limited down hole equipment, no subsurface safety valve and minimum controls.

3.5 Production of the Methane Gas

The well will need to be artificially enabled for production. It is possible to do this in one of three ways, or as a combination of the three methods:

- Reduce or increase the pressure to a position out with the hydrate stability zone. Pressure reduction could be achieved, but only by applying large draw down pressures across the borehole. This type of draw down in conventional gas wells has historically led to localised hotspots and because of the increases in velocity around localised hotspots erodes the sand management system. However this gas has such a quantity of water production that this risk will not be relevant. To over pressurise the reservoir to the point where hydrates are destabilised is not practicable as you are trying to increase the pressure in the entire reservoir and this would require large capital investment water injection equipment.

- Increase the temperature around the borehole, thus dissociating the gas from the hydrate structure. This would be difficult in deeper waters owing to the cost associated with steam injection or in situ electric heating systems.

- Utilise a chemical to breakdown the hydrate to liquid water and gas. Chemicals suitable for this could be methanol or glycol.

The well will also need to be capable of monitoring borehole temperature, via a temperature gauge in the wellbore, such that adjustments can be made to the gas flow rates via the use of a choke. The well will also need to be able to remedially repair borehole blockages of hydrates, should gas production be shutdown, and the wet gas being produced were reformed as hydrate plugs or blockages.

3.6 Gas Evacuation Options

The traditional method for transportation of natural gas has been to use a pipeline infrastructure so that conditioned, or unconditioned gas, can be exported from the production facility to an onshore processing and transportation hub. An example of this would be the Shell U.K. Exploration and Production pipeline system, that allows transport of produced associated gas from the Brent Field in the East Shetland Basin to a land fall processing and transportation hub at the St Fergus gas terminal in the North East of Scotland.

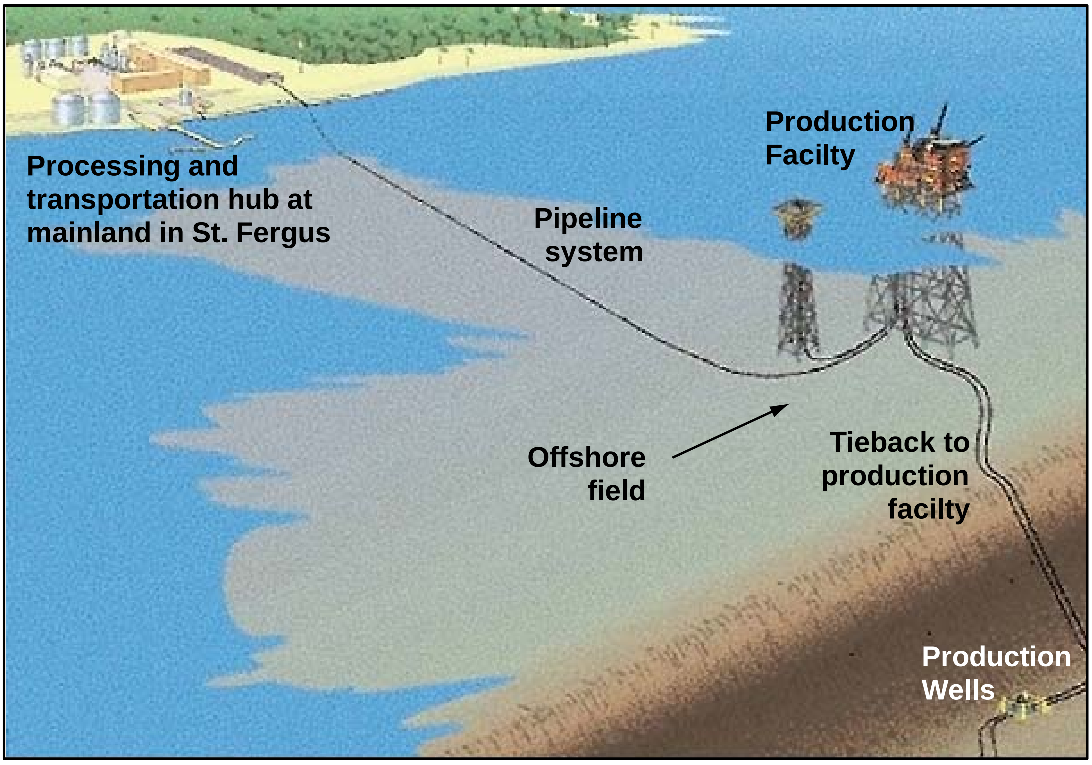

Figure 29: Traditional Natural Gas Transportation Method (19)

Owing to the remoteness of the Methane Gas Hydrate accumulations from the continents and the likely lack of a pipeline infrastructure, alternative means therefore need to be considered for the delivery of the product to the market place. Briefly options considered are:

- Pipeline.
- Floating Liquid Natural Gas (FLNG).
- Compressed natural gas (CNG).
- Hydrate for gas transport.

3.6.1 **Pipeline**

The pipeline option, whilst technically feasible to build and install, it would be prohibitively expensive in nearly all circumstances, unless a near field pipeline network could be accessed. The technical challenges faced trying to lay a pipeline in 1000 metre water depth are significant. The amount of compression power required to compress the gas so that it can be transported, would also be prohibitively expensive and would require substantial investment in Power Generation to drive the compression train.

3.6.2 **Floating Liquid Natural Gas (FLNG)**

This is an available technology that has the potential to enable the exploitation of remote methane gas hydrate accumulations. The concept utilises a gas liquification plant mounted on the processing facility, which can process the gas as LNG. The LNG is transferred to carrier ships that deliver the product to spot price or contract price world markets. Whilst this is available, cost of development can only be borne by a significant gas accumulation as part of a full field development plan.

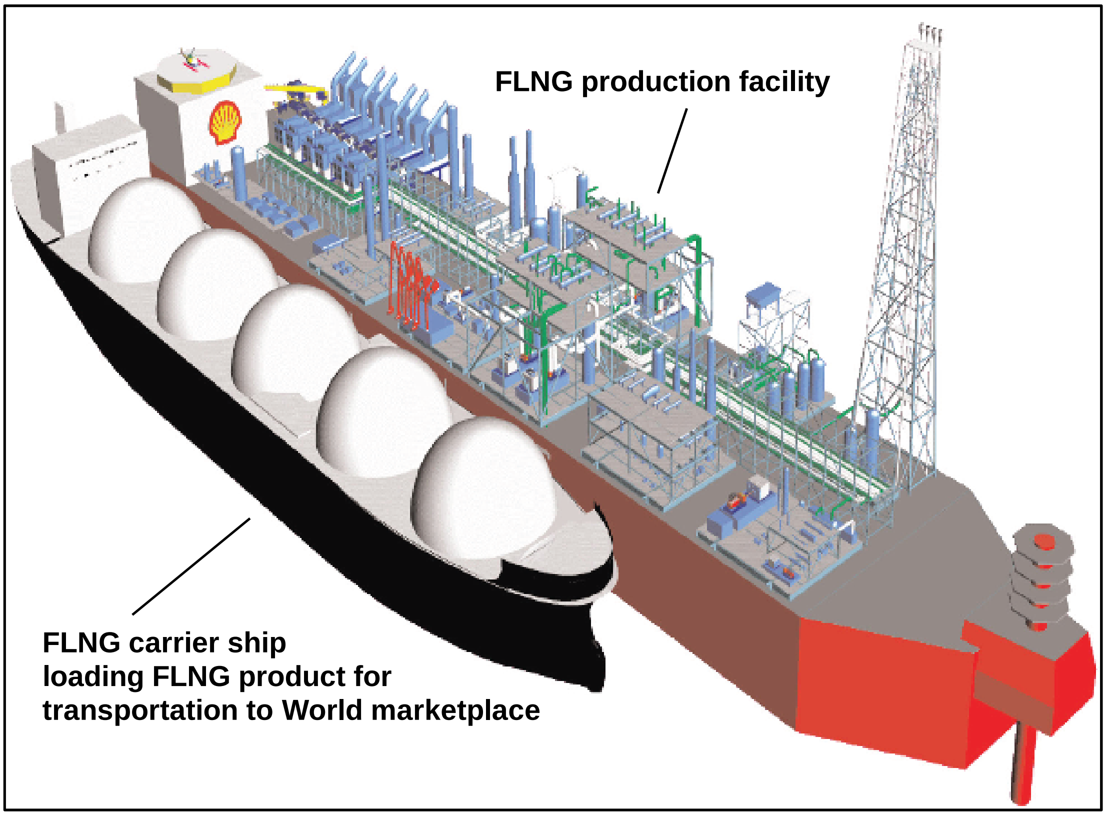

Figure 30: FLNG Production Facility (39)

3.6.3 Compressed Natural Gas (CNG)

Compressed natural gas is a proven technology that has been used in small niche applications for many years. An example of this would be vehicle transport of compressed gas in pressure vessels charged to 3000 psig and above. Large scale transport of gas as CNG has been generally seen as uneconomic, due to the relatively small volumes of gas that can be accumulated per unit capital cost of a facility for compression. Research has established that Cran and Stenning Technology (now NG have developed a coiled piping storage system that can be installed on a ship with thousands of feet of 6" pipework (Tubing/Casing) being wound into 45 feet carousel reels for the storage of compressed gas. The volumetric capacity of the vessel is not as large as the FLNG, but the process costs are lower, therefore this method could have potential as an inter-field link transport facility, filling up with methane gas from one field and transporting it short distances to the main processing facility, or in times of FLNG carrier ship shortage, it could be utilised for additional product storage. Interestingly, the carousel pipe storage system was patented by Enron, whom Cran and Stenning worked for in the 1990's.

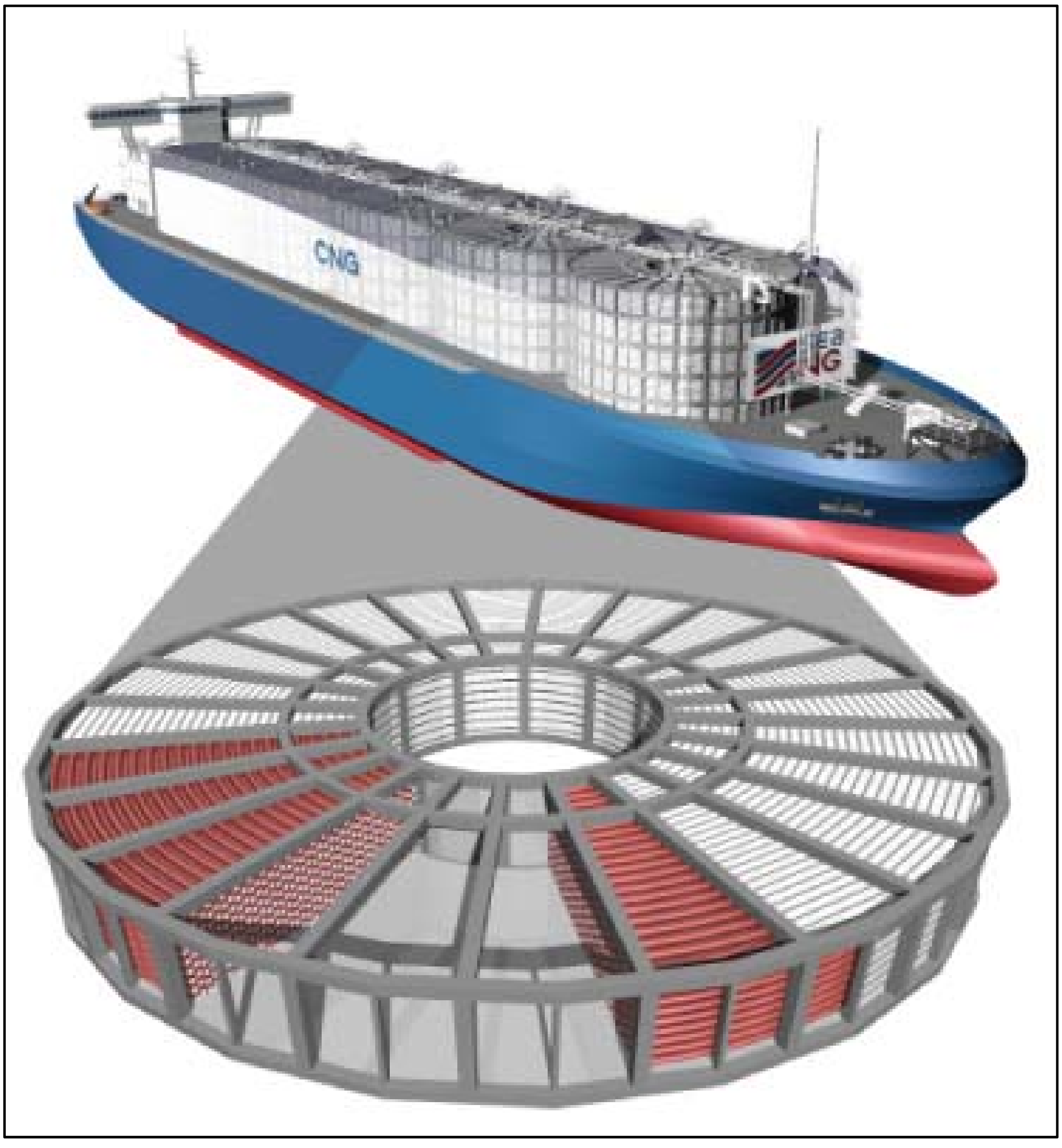

Figure 31: Compressed Natural Gas Transportation (40)

3.6.4 **Hydrate for Gas Transport**

A Norwegian joint industry project (JIP) (41) was set up to review the potential of deliberately forming gas hydrates, and maintaining the hydrate for ease of transport. This would be like transporting blocks of ice. The JIP confirmed that the process of formulation was simple. Many unanswered questions remain, however, and the system has not been confirmed as economically viable. A watching brief should be maintained on this initiative and options such as only partially forming hydrate i.e. slush should be further investigated.

3.7 Transport options technical maturity and cost impact analysis

It is not practicable to do an economical analysis of the options detailed namely pipeline, FLNG, CNG, or hydrate for gas transport, as there are too many variables to allow definitive analysis. The depiction (42) in Figure 32 offers subjective analysis of what could be the best option for transportation of Methane Gas from deepwater methane gas hydrate accumulations to the market place, depending on volume in place and distance to market.

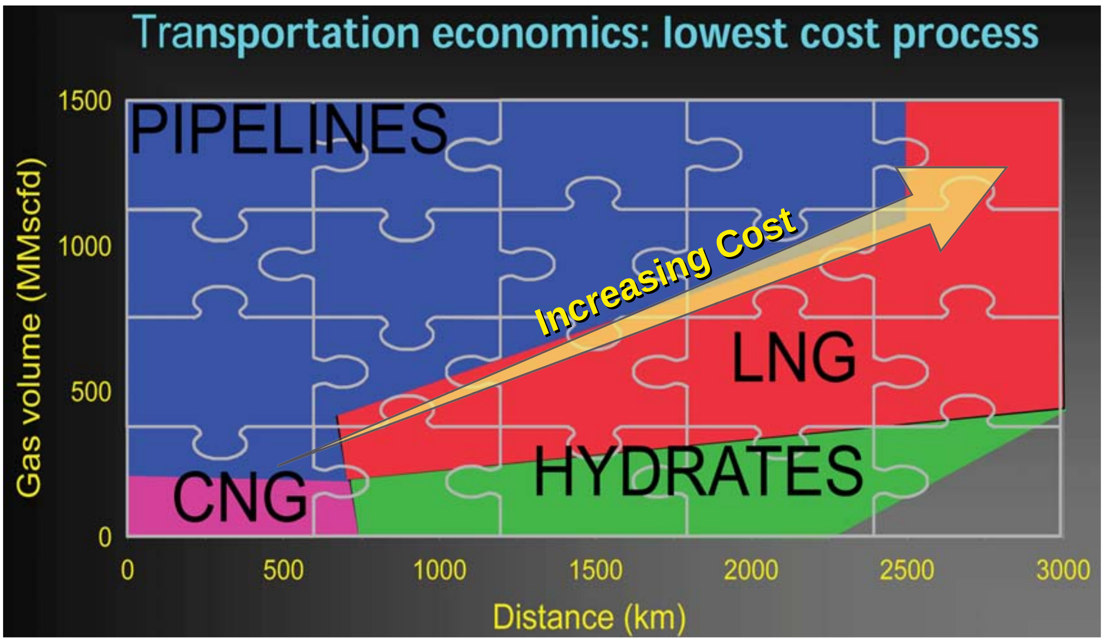

Figure 32: Transportation Economics (42)

The developments would have to have an economic analysis on a case by case basis to determine the optimum economic solution for the particular field. It is important to recognise that a field in the Gulf of Mexico with a pipeline infrastructure nearby will be totally different to an accumulation in the middle of an ocean thousands of miles from any other infrastructure. Each case needs to be handled on its own respective merits.

3.8 Sub-sea Infrastructure

Traditional sub sea wellhead tree and manifold systems as depicted in Figure 33 are costly in terms of Capital Expenditure and Life Cycle Facility Operating Expenditure. It is vital for the viability of methane hydrate exploitation that a system is developed that can provide a safe and cost efficient methodology of production.

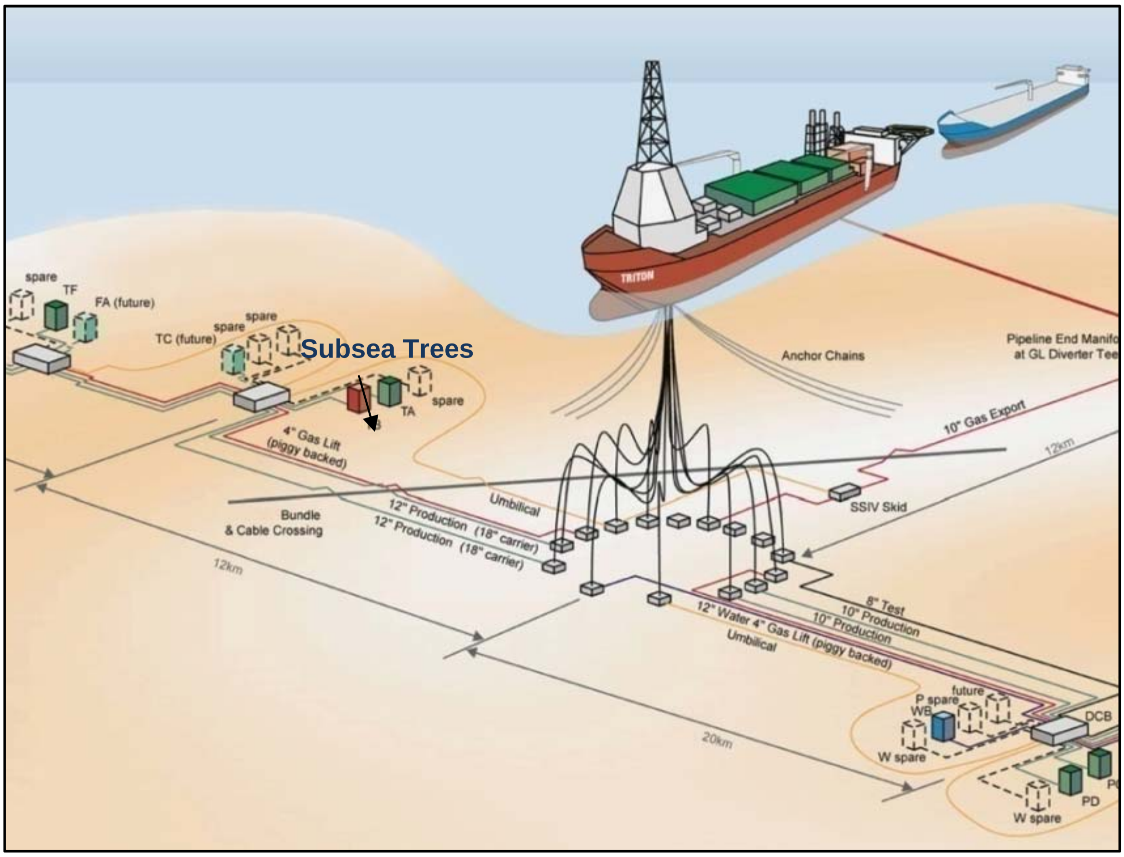

Figure 33: Traditional Subsea Wellhead Tree and Manifold System (10)

The functional requirements for a modular sub sea system are:

- Can be deployed from a DPV.
- Modular construction.
- Fully standardised.
- No special tooling.
- Low cost.
- Reliable.
- Reusable.
- Modular maintenance.

3.9 Field Development Plan (FDP)

The objective of any field development plan is to be able to demonstrate the business case for the potential hydrocarbon resource over the life cycle of the field. Field development planning is complex and a requisite of the FDP is to optimise a range of uncertainties to safeguard the project economics. The Plan provides an evaluation of field development alternatives together with the selection of an optimal development concept. The FDP includes a range of forecasts/reserves, conceptual well types/numbers/locations, conceptual surface engineering requirements, costs and an economic assessment, including an analysis of risks/contingencies and requirements for additional field appraisal to reduce uncertainty to an acceptable level

Resource volumes are tied to the project or activity that develops them and are generally reported by field. The term reserves is used for resource volumes associated with a project that is technically and commercially mature, to the extent that funding is 'reasonably certain' to be secured. Resource volumes that do not meet these criteria are classified as Scope for Recovery (SFR). Proved reserves are the portion of reserves that is reasonably certain to be produced and which will be reported externally. If no proven reserves can be assigned to a project, then the related resource volumes are to be retained as SFR.

The concept of reasonable certainty requires hard field data, and thorough evaluation to support the numbers. The implication is that as more data becomes available, upward revision is much more likely than negative revision.

3.9.1 **Appraisal/Data Gathering**

Lack of understanding of commercial methane hydrate accumulations is such that before any economic commitments can be made, it is vital that an appraisal drilling campaign is undertaken. Much of the deepwater locations have already been explored by the DSDP, ODP and other joint ventures. Data gathering from those expeditions is important for development planning. It would not be unusual to have to pay for the data from the scientific bodies that conducted the expeditions. Appraisal is a term generally reserved for the data acquisition through drilling wells to supplement the delineation and characterisation of a field. In essence, though, there is no difference between appraisal in this meaning and any data gathering that helps refine the decisions towards, and optimisation of field development. Therefore the data gathering from the scientific expeditions has as much importance as information acquired during the appraisal drilling campaign. Both efforts are necessary because they help develop a greater understanding of the prospect and thus complement efforts to mitigate risk, and better understand outstanding uncertainties.

The geophysicist or geologist typically drives early data acquisition. As the opportunity matures, other disciplines may drive the acquisition programme: the petrophysicist and reservoir engineer for rock property and fluid data, production and well engineering for rock mechanics and stress fields, development engineering for metocean and slope stability data. Inefficiencies at this stage can have a major cost / time impact later in an opportunity lifecycle.

Justification of data acquisition will be done based on a Value-of-Information (VOI) exercise. A good appraisal strategy, or VOI study, identifies the value of the data, but also suggests how to extract that value from the data and apply it to the project planning. It is important for the efficient management of data to be gathered, that the clear link is made between what data is required for what purpose, and once gathered how it will be used in further work. It is therefore recommended that an appraisal drilling programme needs to be planned to obtain information for Project Planning.

The main elements derived, therefore, from the data gathering and appraisal drilling will include:

- Data collection and quality control
- Stratigraphic review / correlation - using biostratigraphy and sequence stratigraphy. The correlation should also be consistent with the structural interpretation.
- Sedimentological review / depositional modelling, ensuring consistency with the subsidence, sediment supply and other controls on sedimentary deposition paying particular attention to methane dissociation potential by subsidence.
- Structural interpretation / mapping - of the reservoir model must tie seismic and well depth data with reference datum.
- Rock properties / Petrophysics - porosity, saturation, and permeability derived from log analysis integrated with laboratory analysis and quantitative

seismic analysis. Additional evidence / support will come from reconciliation of reservoir behaviour with any production, testing, sampling, wireline logs, seismic analysis or core analysis.

3.9.2 Reservoir Description

A static reservoir model will be required to understand the reservoir and it is an area currently of huge uncertainty when considering methane gas hydrates reservoirs.

The static reservoir model will be coordinated by the Production Geologist with key input from the Geophysicists for the structural interpretation / mapping and Petrophysicists for the rock/ sediment/ HSZ properties / Petrophysical interpretation. As stated previously, rock properties will also be vitally important for future seismic calibration analysis and interpretation.

The resulting reservoir description will form the primary input to the construction of the reservoir static model. This will also provide the primary structural input for the Probabilistic Analysis and is a fundamental for establishing a range in the deposition of the sediments, the internal properties of the reservoir and the trap geometry.

3.9.3 Gas/Fluid Model

The objective of gas or fluid modelling is to understand the composition of reservoir gas/fluids and to predict their behaviour under different reservoir and producing conditions, as input into subsurface, hydraulics and process modelling and for the development of commercial assumptions. An accurate fluid model is a fundamental element of static and dynamic modelling, well number requirements, process requirements and reserves calculations. Obtaining good samples is often the key justification for testing of appraisal wells. The challenges associated with obtaining samples from a methane gas hydrate well are, as stated previously, central to the challenges faced by the dissociation of the methane gas from the hydrate lattice structure. This will have to be carefully planned to ensure reservoir condition samples are obtained. A pressurised core from the drilling of the HSZ will be required, and will provide valuable information about the depositional environment, saturation conditions, and porosity rock characteristics. A range of tests will need to be devised to build a picture from the samples obtained, both from the subsurface and the well tests.

Gas compositional data and characteristics will be obtained from gas samples. There is always the chance that the 'guest' molecule might not be methane - it could be H_2S from thermogenic sources.

3.9.4 Static Model

The particular aim of this static reservoir modelling is to capture and evaluate the range in architecture of the sediments, as well as their properties. It is a fundamental tool for addressing and evaluating uncertainties within the reservoir, and the challenge will be to build from the traditional model process depicted below, a methodology for the understanding and analysis of a methane gas hydrate reservoir.

The static reservoir model will provide the basis for deterministic volume calculations. The deterministic route is one of two ways for estimating in place volumes. The other one is the probabilistic route. Through deterministic scenario modelling, the static reservoir model can lend support to the probabilistic method in providing field-wide average reservoir parameters for a range of model outputs. The results of both methods have to be reconciled to come up with a final probability distribution of volumes.

3.9.5 **Dynamic Model**

The dynamic model will build on the static model, but allow interrogation of the effect of key subsurface uncertainties on life cycle flow performance, such that the surface hardware options will be matched to the predicted subsurface scenarios. It is believed that the subsea infrastructure specification can be greatly reduced as the life expectancy of the wells are less, and the cost for drilling is low enough to make a well expendable in a high number of wells field.

The range of possible dynamic reservoir models available today is vast but no experience exists for the development of deepwater methane gas hydrate fields. The dynamic model, when built, will be required to predict the

- Dynamic behaviour of the gas/fluid within the reservoir
- Well and reservoir behaviour
- Surface processing constraints
- HSZ behaviour

The level of detail in the dynamic model will focus on what is relevant in helping to make the next milestone decision in the exploitation of methane gas hydrates.

3.9.6 **Probabilistic Volumetrics**

The objective of a probabilistic volumetric estimate is to capture the full range in possible hydrocarbon volume, (in place and reserves) expressed as a probability distribution.

The volumetric probability distribution is a key deliverable of the field study. It sets the scene for management expectations of the field. It forms the basis for marketing efforts and provides a measure of uncertainty to be considered. The width of the uncertainty distribution will affect the assessment of the development concepts, in terms of flexibility and robustness. The probabilistic route is one of two ways of estimating reserves, the other one being the deterministic route. The results of both methods have to be reconciled to deliver a final probability distribution of volumes, with estimates probabilistic volumes.

Integrity, in reserves booking, is a key aspect of the economics and value credited to a hydrocarbon field. It is important that this process is fully developed for methane gas hydrate accumulations, as much of the attributed volume classification has not been determined with the rigour of the current oilfield processes. Investors and Governments will be very interested in the method of determining reserves before financial commitments are made.

3.9.7 **Deterministic Analyses**

A deterministic analysis will be required so that the sensitivities of discrete physical realisations of the development concepts can be compared to determine 'best' option scenario matching.

Deterministic analyses are central to uncertainty management for reserves calculation. This uncertainty management requires parallel deterministic and probabilistic volumetric assessments, with reconciliation between the two.

The methods employed are applicable to any output from the models' (field life, plateau length etc.)

3.9.8 Well Modelling and Design

Optimisation, of conceptual development well design is a key input into the FDP process, which requires integrated effort to be carried out successfully. Typically during an opportunity, Select Phase (Table 4), says it is the Business Opportunity Manager who will own the work and be responsible for pulling together Petroleum Engineering, Well Engineering and Project Engineers inputs. Although high levels of work detail may be required for various well design / evaluation aspects, this is normally still on a conceptual, rather than individual well basis.

Table 4: Project Development Phases (10)

PHASE 1	PHASE 2	PHASE 3	PHASE 4	PHASE 5
IDENTIFY	FEASABILITY	CONCEPT	APPROVAL	REVIEW
The identify phase is aimed at determining the potential value of the opportunity.	The feasibility phase will review the potential options for practicability.	The concept phase is intended to address the major uncertainties within the preferred project	The approval phase is when financial investment decisions are given for the planned scenario.	The review phase is to learn from what was planned versus actual and feed the learning into future planning

Conceptual well design is all about optimising the number and type of wells (reservoir drainage points) consistent with full life-cycle needs. It links the desire to minimise capital and operating expenditure with the need to maximise hydrocarbon recovery and optimise data collection.

Well design is typically an inside-out process with production tubular and reservoir inflow needs driving the overall configuration of the actual well.

Understanding of reservoir drainage needs

This requires knowledge of the likely drainage mechanism of the field, the geology and the fluid or gas type. Knowledge of these will give an indication of the type, and number of reservoir penetrations, that will be optimal for the field. This knowledge is an 'output' from the static / dynamic modelling or, early on, from field analogues.

Inflow system design

Based on an initial understanding of the reservoir and its likely drainage needs, well inflow options will be evaluated and modelled. This will typically include looking at different hole configurations (horizontal, vertical, slanted) and their fit to the reservoir, any dissociation issues that may drive a different well design, sand control requirements and actual off-take rates required. Studies required for development of a Methane from Hydrate include but not limited to:

- Analytical inflow assessment.
- Sand prediction/control.
- Compaction studies.
- Subsidence.
- Well configuration impact on Ultimate Recovery (UR).
- Well impairment analysis.
- Well evaluation needs.

For Methane Gas Hydrates, it is approximated that the well productivity will be circa 0.14 million m^3/day (~5 million SCFD). This has been calculated based on a 5 year timescale shown in Figure 34.

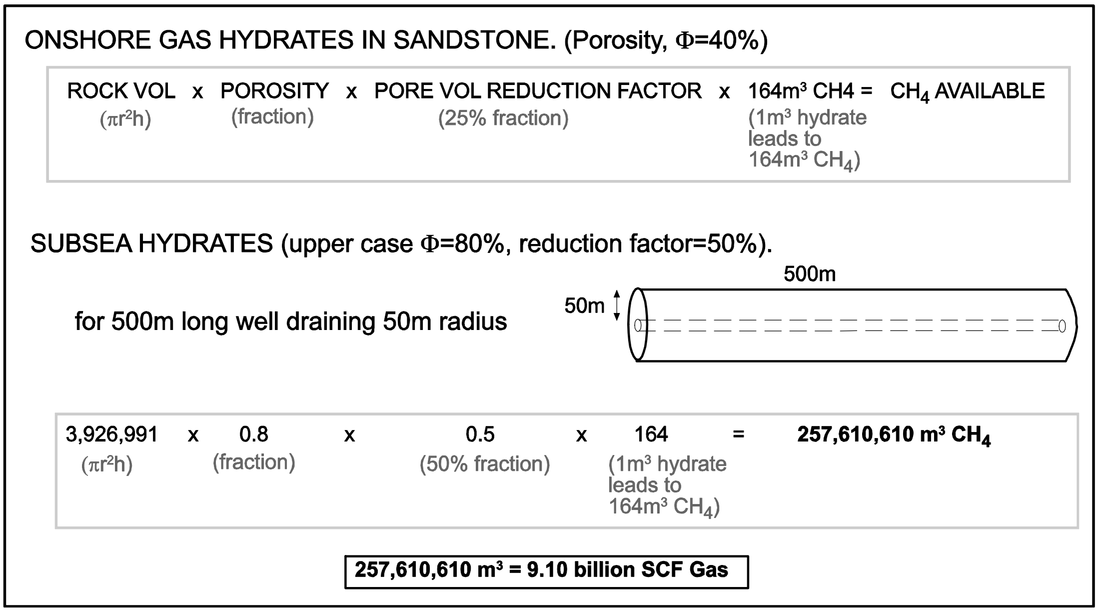

Figure 34: Well productivity calculation for five year period.

Outflow System Design

A large part of outflow system design revolves around the modelling of tubular sizing to ensure there is adequate production potential from the well over its lifecycle. This requires an understanding of reservoir performance and production forecast to ensure tubulars are correctly sized for total life cycle.

Based on experience of water wet gas wells and flow rates of 0.14 million m^3/day. It is estimated that 2 7/8” or 3 1/2” tubing will be required. This has been checked with PipeSim and confirmed as acceptable.

Well Engineering Design

Well needs will be fully developed, once the inflow and outflow requirements are fully known. This requires the construction of a casing/borehole infrastructure that will enable the requisite size of production tubulars and equipment to be installed. This has been fully described previously in Conceptual Well Engineering - Overview.

3.9.9 New Technology Assessment

To ensure the possibilities offered by new well engineering technology are captured, new technology options need to be formally addressed as part of any well design process and new technology application will be managed by a Value Assurance Framework.

3.9.10 Substructure Definition and Modelling

The different types of structure required to support the exploitation of methane gas hydrates includes:

- Ship - supports production facility and offloading system and logistical support.
- Dynamically positioned vessel - drilling and intervention activity.
- Offshore Loading Units - used for tanker offshore loading.

3.9.11 Export System Definition and Modelling

The export method may include one of the following:

- Pipeline to an existing pipeline.
- FLNG.
- CNG.
- Hydrate for gas transport.

On a case by case basis, an assessment of the most favourable (technical and economic) export methods would need to be determined.

3.9.12 Production Facilities Definition and Modelling

This will identify the size and weight of equipment required and layouts to enable selection of the most appropriate support structure for a given field development. In the early phases of a project, this work will form a significant part of detailed design and, therefore, will have a large impact on Net Present Value (NPV). In our plan, a contractor will be paid a tariff from production to deliver the process vessel and facility. Our role on the project then becomes one of Value Assurance.

3.9.13 Cost Estimation

A clear understanding of the risk costs associated, with different options, needs to be worked out for all phases of a field development opportunity.

The field development must have a life cycle approach. Successfully completing value assurance requirements, as defined in the process, will ensure successful progress of the project through the phases depicted in Table 5

Table 5: Project Development Phases (10)

PHASE 1	PHASE 2	PHASE 3	PHASE 4	PHASE 5
IDENTIFY	FEASABILITY	CONCEPT	APPROVAL	REVIEW
The identify phase is aimed at determining the potential value of the opportunity.	The feasibility phase will review the potential options for practicability.	The concept phase is intended to address the major uncertainties within the preferred project	The approval phase is when financial investment decisions are given for the planned scenario.	The review phase is to learn from what was planned versus actual and feed the learning into future planning

As the project development matures through each phase, the level of technical certainty will increase. This enables progressively more detailed cost estimates to be developed from an initial un-risked Authorisation For Expenditure (AFE) P50 which has an uncertainty of +/- 40% to the final approved P50 AFE which will be fully risked and have an uncertainty of +/- 10%.

3.9.14 **Economic/Commercial**

Economic evaluation and screening processes will be used. Within the FDP context, these evaluations are a fundamental tool for ranking options to determine the most appropriate option for a development.

Economic evaluation and screening of investments involves:

- Open and honest declaration of cost and risk per option (no hobby horse).
- Assessment of the risks and uncertainties associated with the option and quantification of the likely downside.
- Justification of the business case for the investment requested.

Further detailed work is required on Cost Analysis

3.9.15 **HSE**

All activities will be planned and performed in order that risks are understood, and mitigation steps taken to reduce the risk to (ALARP) As Low As Reasonably Practicable whilst complying with all statutory requirements. Field Development Planning of methane gas hydrates will require an identification of all HSE needs for the opportunity, and assurance plans for managing them. It is important to state that conventional thinking will not deliver the project for society. We need to fully understand the behaviour of methane gas hydrates, and use this understanding to challenge all conventions and standards, so that the opportunity can be realised in a safe and economic manner.

3.10 Methane Hydrate Resource Classification Challenge.

A review of the available literature which tries to define the volumetric potential of methane gas hydrates (17), has confirmed to the author that the volumes being expressed are hugely speculative, and have no foundation when compared to the rigorous definition, as detailed by the Petroleum Resource Classification Requirements, as depicted in Figure 35.

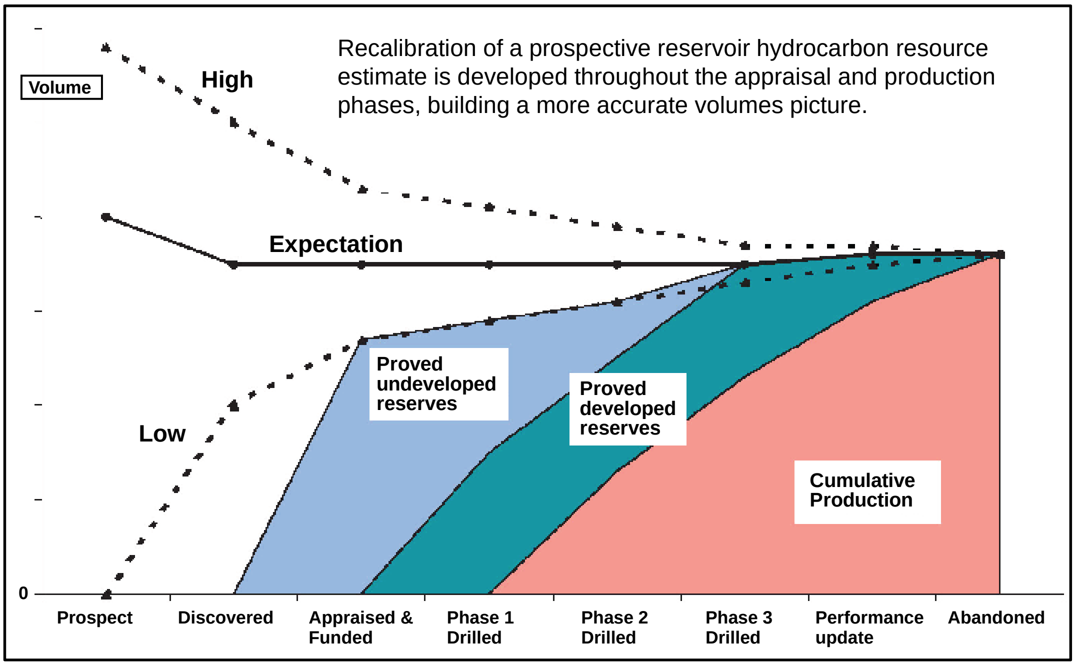

Figure 35: Volumetric Potential of Methane Hydrates (courtesy Shell)

As we gain understanding of the reservoir by the analysis of appraisal well data, we can recalibrate all estimations in line with current hydrocarbon resource classification convention, and ensure we build a clear picture to justify financial investment decisions and reserves bookings.

4 Conceptual Engineering Design

4.1 Description of the seabed mounted Methane Gas Hydrate Exploitation System

The design that evolved from the literature search relates to a gas hydrate exploitation apparatus, operable as a subsea installed well drilling, production and well effluent disposal system.

As stated, conventional subsea oil and gas well drilling and production systems are designed to access hydrocarbon reservoir strata many thousands of feet under the seabed. This makes these systems technologically complex and high capital cost. A typical deepwater drill ship (Figure 36) in the Gulf of Mexico will cost approximately $500,000 per day. The use of such vessels would immediately make methane hydrates uneconomical to exploit at current gas prices, as payback on investment would not be achieved in an acceptable timeframe for investing.

Figure 36: The "West Navigator" Drillship used on Shell deepwater projects

The seabed mounted Methane Gas Hydrate Exploitation System (patent application submitted) design provides a seabed methane gas hydrate extraction system that can be operable as a subsea well drilling site, a subsea gas production and well effluent re-injection site. The configuration avoids disturbance of the point area around the hydrate zone and any active gas seepage is captured inside the segmented structure.

The system comprises a segmented seabed structure with modular subsea well drilling, gas production and effluent process (filtration and pumping) infrastructure attached to the segmented structure. It also allows for connection to subsea intervention vessels and / or gas export process and storage facilities.

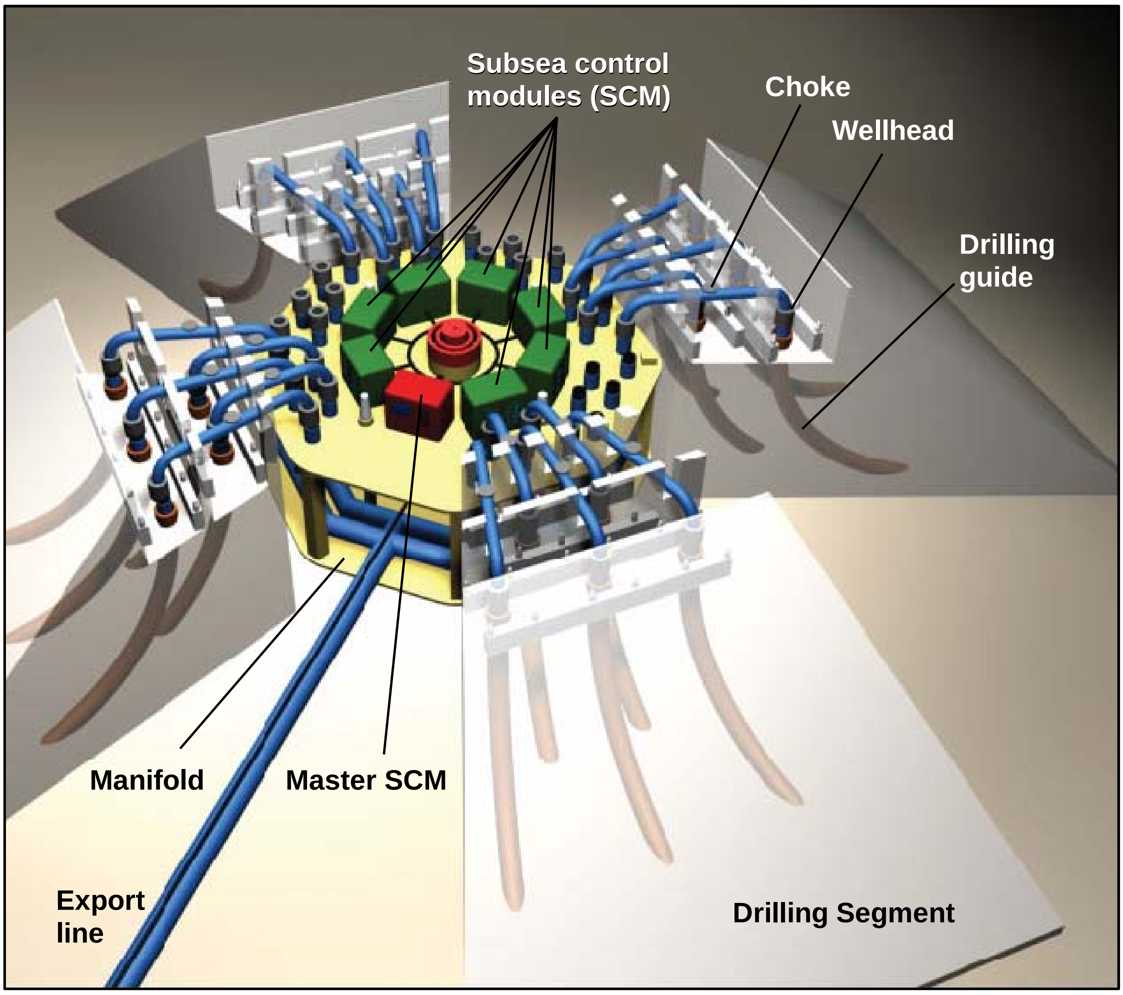

Figure 37: Seabed Methane Hydrate Extraction System (43)

This design simplifies the technology required for the exploitation of seabed methane gas hydrate and also allows for a lower cost installation vessel to be used for the operation (see section 4.2). Basically, the design allows for a vessel of opportunity to be utilised for the well drilling operation, as opposed to a higher cost conventional semi-submersible drilling vessel or drill ship.

The design provides modular flexibility in order to deploy well drilling, gas production control / export, effluent filtration and effluent disposal modules onto the segmented structure. The configuration of the components into segments allows for the apparatus to be deployed and, or, removed in stages. It allows for multiple lower cost slim hole wells to be drilled from one central subsea location.

The present invention does not require the installation of a Subsea Production Tree system (known as a Christmas Tree in the oil industry). This saves capital costs (approximately $2.5+ million per tree). It should be noted that conventional deepwater trees, as depicted in Figure 38, provide excellent and safe production from conventional fields are also acceptable for methane hydrate gas production but may be too expensive.

Figure 38: Conventional deepwater Christmas Tree (courtesy FMC)

The configuration of the components allows for the site to be completely decommissioned, leaving no infrastructure in place.

4.1.1 **Detailed design**

An example of the design will now be described in detail, by referring to the accompanying drawings in which:

- Figure 39 shows a first perspective of the seabed system;
- Figure 40 is a perspective representation of the well drilling segment;
- Figure 42 is a side view representation of Figure 40;
- Figure 43 is a perspective representation of the central production manifold;
- Figure 44 is a side view of the central production manifold system

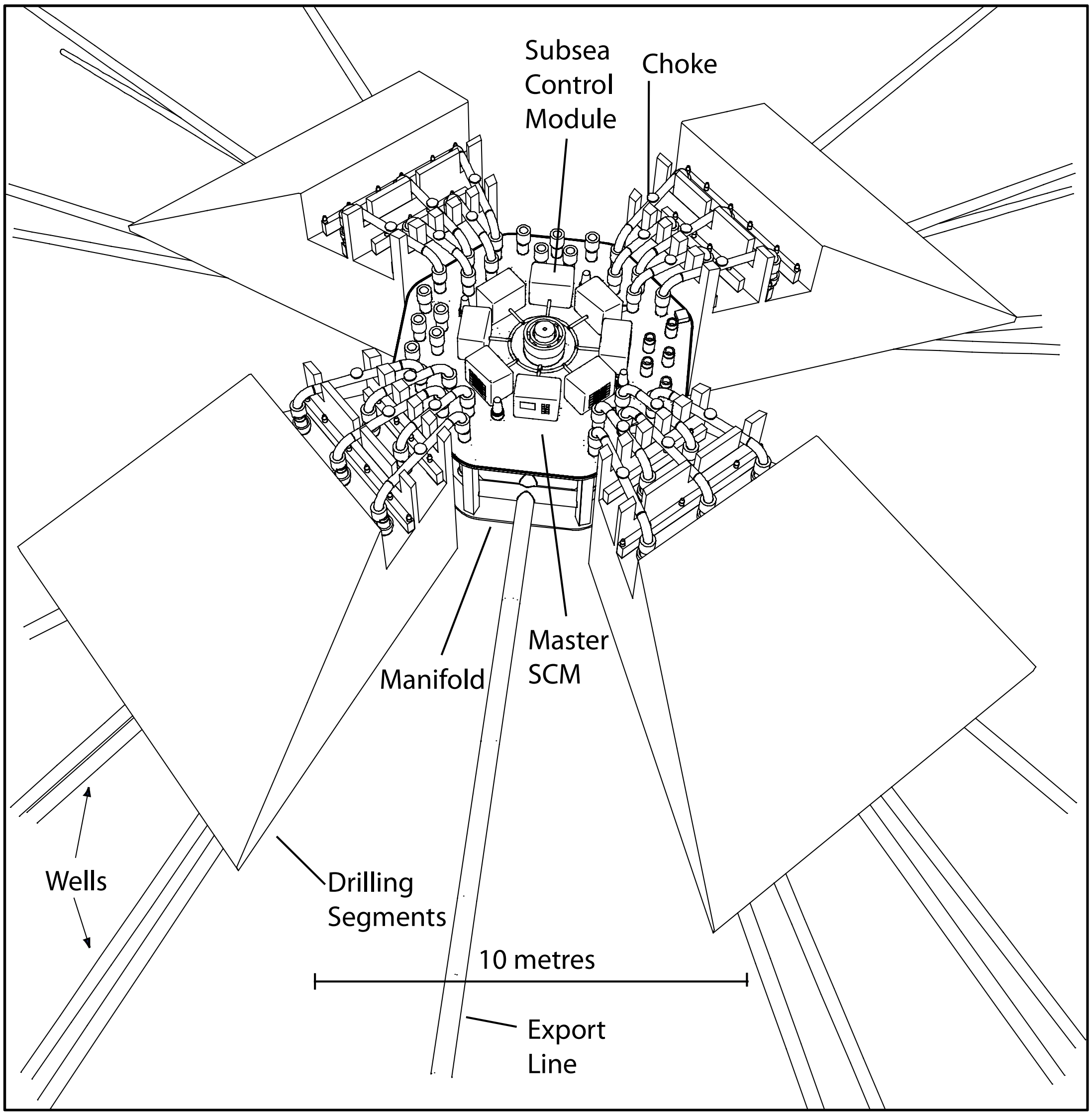

Figure 39: Fully constructed seabed system (43)

Figure 39 shows the fully constructed system. It is comprises a series of individual well drilling segments, which surround a central production manifold. A scale is included to give an idea of size.

The fully constructed system will be placed such that it can act as a hub for the well drilling operations and a gathering station for the methane produced from the wells. The gas would then be stored and transported to market.

The system (43) will be modular in nature and have the ability to allow simple removal and repositioning of the following:

- Well entry architecture
- Gas production control modules
- Gas export pump modules
- Gas and effluent containment structure
- Well effluent separation modules
- Well effluent disposal / pumping modules

Located on the central manifold, in Figure 39, are the Subsea Control Modules (SCM) and production Chokes to control gas flow. There may be a single SCM to control the wells, or production requirements on each wedge segment, or a single SCM to control the wells on all wedge segments. A master SCM will be required for the manifold itself. The SCMs allow for electro-hydraulic control of all the functions on the seabed, such as sensors and valves. A remote computer station on the production host controls the subsea SCMs.

Figure 40 shows the well drilling segment apparatus from a prospective view showing the wellheads. The perspective of the apparatus can be seen with the casing of each well moving sub-surface.

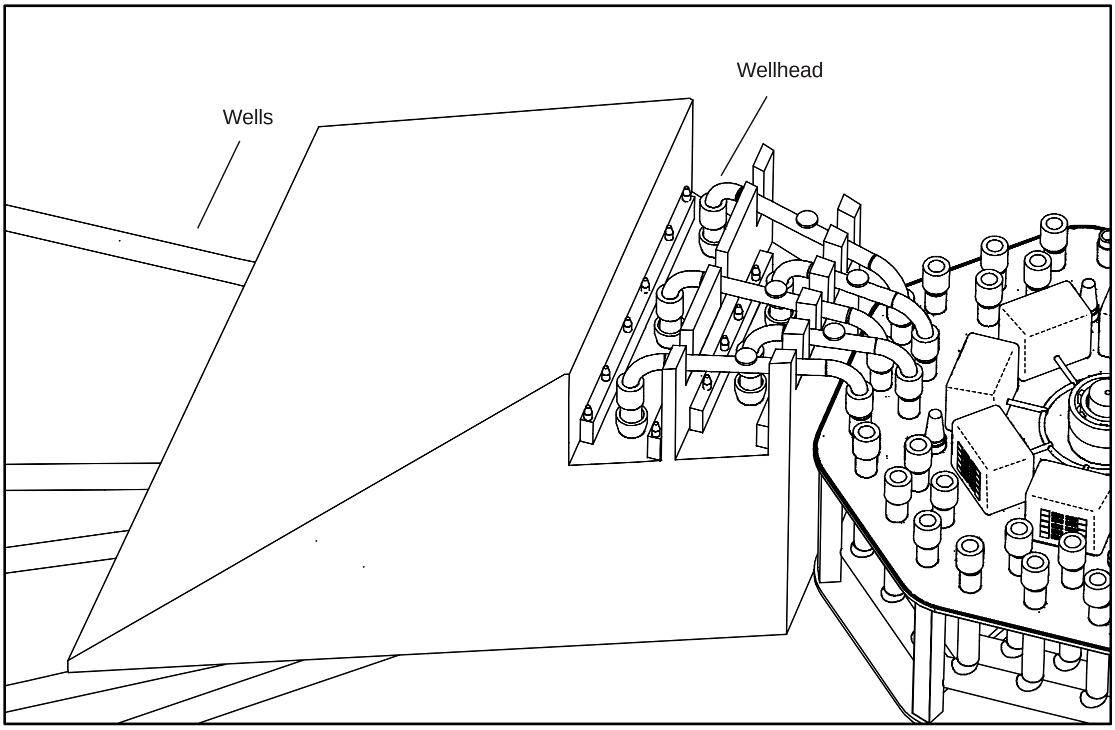

Figure 40: Well drilling segment apparatus (43)

The manifold would be deployed to the seabed first. It would locate on a conventional subsea wellhead guidebase, shown in Figure 41.

Figure 41: Conventional subsea wellhead guidebase (19)

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The Guidebase is an item of conventional oil industry equipment of known size (12 ft between posts). Individual well drilling segments would then be deployed from a vessel and positioned next to the manifold. The fully constructed system, and associated pipe work can be parametrically scaled, as required.

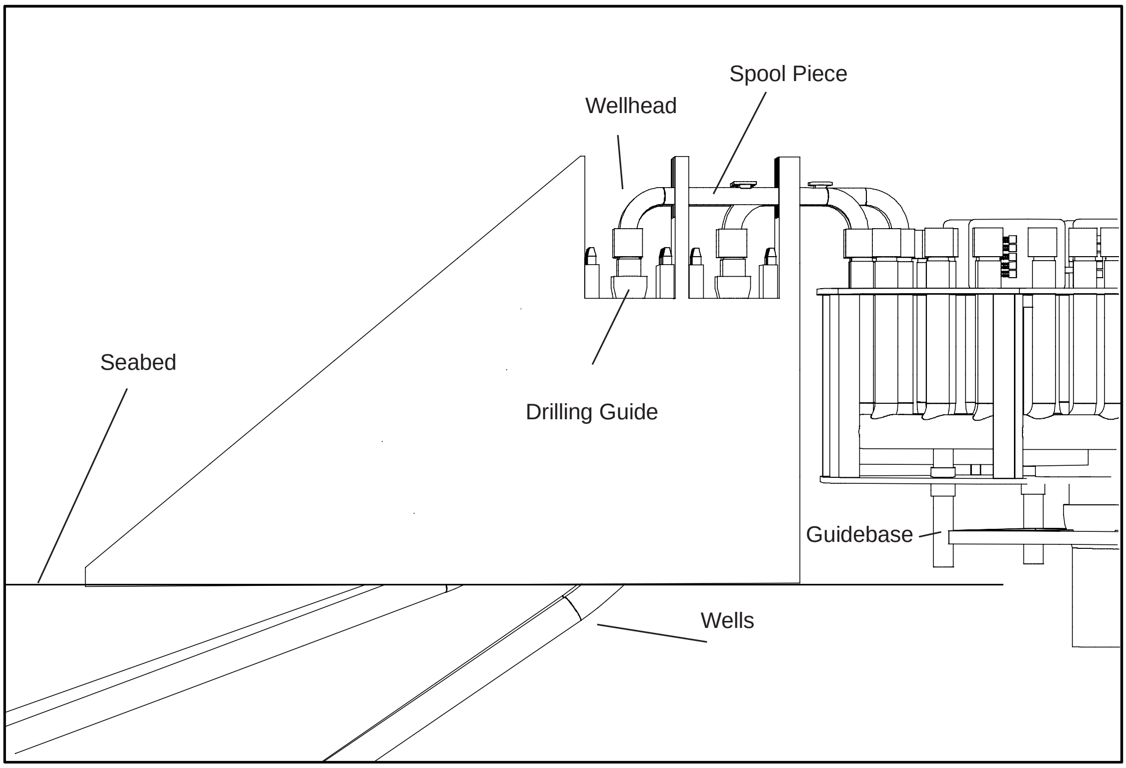


Figure 42: Side view of well drilling segment (43)

Figure 42 shows a side view of a well drilling segment positioned on the seabed.

Each well on any segment would be attached to the central manifold by a remotely deployed tubular spool piece. This spool piece would be deployed by a Remotely Operated Vehicle (ROV) once a well has been drilled and completed. The operation of locking the spool piece to the wellhead would mechanically activate a closed valve positioned in the wellhead and also on the central production manifold. This would allow the produced gas to exit from the drilled wells through to the production manifold, and thereafter to process and storage. The well to manifold spool piece would hydraulically lock onto the well production bore and the respective receptacle on the manifold.

Each segment will have the capacity to hold up to five slim well / hole slots. A total of up to seven well drilling segments could be deployed. Four such segments are illustrated in Figure 39, giving a capacity of up to twenty wells. Variations on these well numbers would be possible, by linking several sets of apparatus together.

The wells are all drilled from each segment at pre-determined angles. Well diameters for production flow, would typically range from 1 ½” to 7” outside pipe diameter. The angles would be set into the segment, based on the geology and geometry of the hydrate zone. No vertical wells would be drilled from the apparatus, so as to maintain seafloor stability around the drilling / production centre. A series of segmented structures would be arranged radially around a hydrate zone of interest, and production wells drilled into the zone. Typically for commercial needs, it is anticipated that each hydrate well would be approximately 1000m (3000ft) in length, drilled at an angle of deviation which would allow for maximum intersection with the hydrate reservoir zones.

To drill each well, the surface vessel would have to deploy a subsea well control system onto each well drilling guide. This would comprise a hydraulic connector, a series of valves to allow for well control, and a connection to a riser pipe that can extend to the surface vessel. The riser pipe, where used, acts as a conduit for the drilling equipment. These features are conventional oil and gas drilling technologies and earlier in the thesis it was proposed to eliminate the riser system by development of a subsea topdrive system. This would reduce cost and improve vessel safety.

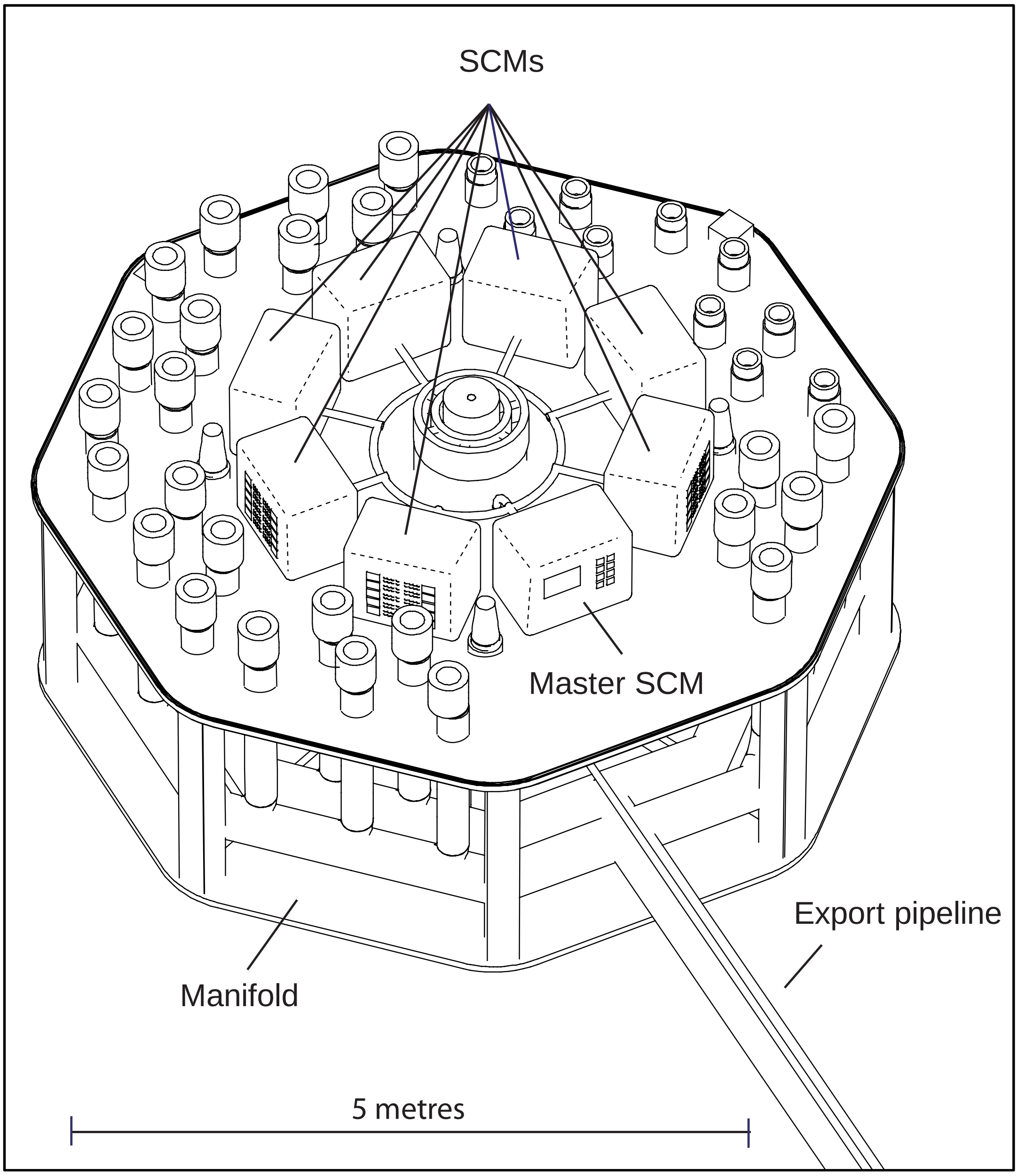


Figure 43: Central production manifold (perspective) (43)

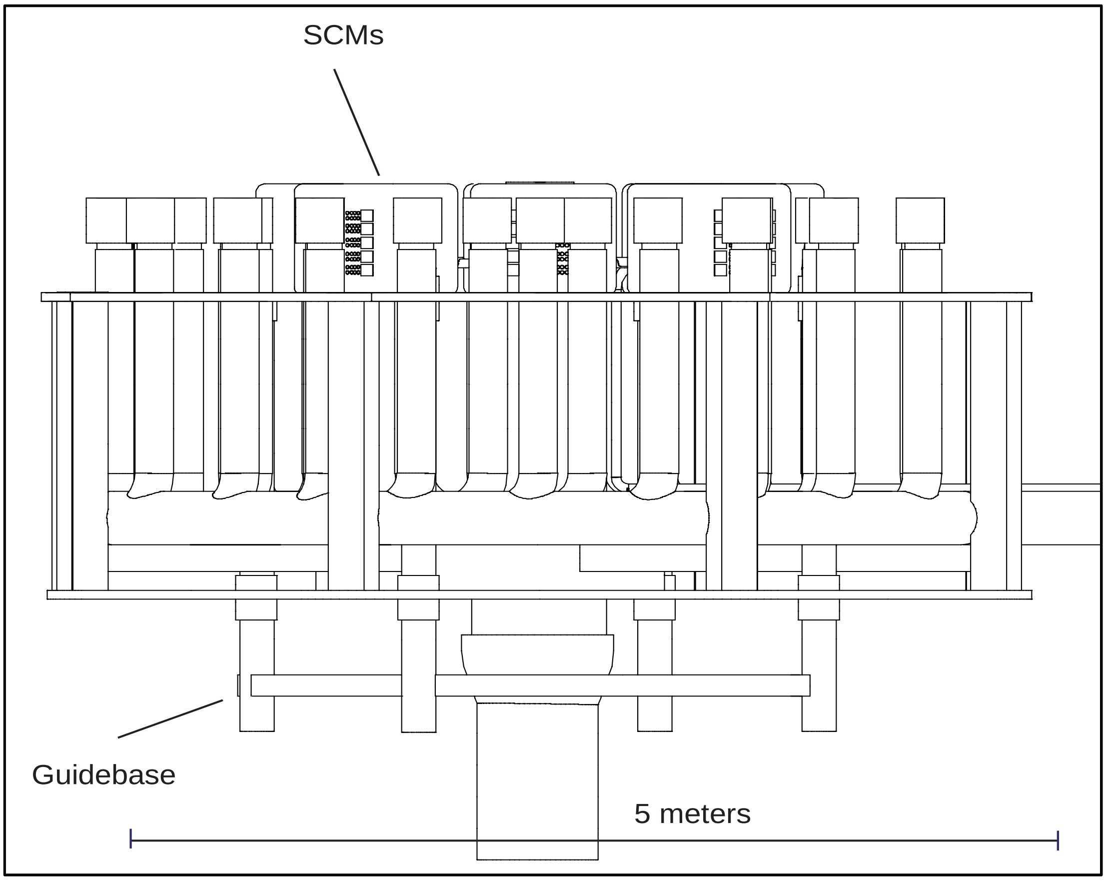


Figure 44: Central production manifold (side view) (43)

Once the drilling riser system is installed the wells would be drilled using conventional slim hole or casing drilling techniques. A series of small diameter wellbore isolating casings would be deployed as required. The casing hangers would be locked into the wellhead.

The casing would be left in-situ complete with a conventional isolation / lubricator valve (or tubing hanger device). This would act as the subsea production tree. This would also lock into the wellhead.

Once the production completion was installed and tested the well would be displaced to nitrogen gas. The isolation valve would automatically close once the drilling riser system was unlocked. The isolation valve would then be closed at this point, preventing any flow from the well.

The drilling equipment would be located on the next well to be drilled. A production spool piece would be deployed onto the wellhead as previously described.

Gas production would then commence, with produced gas from the wells passing through the production manifold to an export pipeline and thereafter to process and storage.

The well effluent (water and solids) could be removed from the gas stream and re-injected into dedicated injection wells located on the system.

4.2 Description of the Floating Hoist - "Vessel of Opportunity" design for deepwater hydrate exploitation (44)

As stated previously, current deepwater practice is to drill wells and run well completions from a floating drilling rig or drillship, which is both expensive and poorly suited for the job.

This thesis proposes a new design, allowing a move away from subsea drilling and completion running from a semi submersible rig or drill ship. This will open up the possibility of lower exploitation costs for methane gas hydrates. By utilising a vessel of opportunity, with specialty equipment mounted on the deck, there will be the option of a much cheaper platform to work from, which will also eliminate the expensive process of converting semi rigs or drill ships from the drilling mode to being ready for completions.

This approach will allow a fit for purpose platform for exploitation of methane gas hydrates. It will also cause significant reductions in cost and environmental impact.

Preliminary estimates indicate considerable costs will be saved by using this approach by avoidance of the costly drilling vessels when compaired to a lower cost floating hoist - “vessel of opportunity”.

Modular subsea completion running equipment will be added to this non dedicated vessel. Modules will be relatively easy to transport to different ports around the world, for use on vessels of opportunity.

The proposed design provides a system and apparatus for hydrate drilling and exploitation, without requiring the use of an offshore drilling rig, or drill ship. In particular, the design comprises the use of modular drilling / completion or other equipment, in conjunction with a floating hoist - vessel of opportunity, to reduce the cost of various operations. Figure 45 below indicates the size the workspace on the stern of a floating hoist – vessel of opportunity, the vessel should be, basically akin to a modern multi purpose vessel (MPV)..

Figure 45: Gulf of Mexico intervention vessel (7)

The design provides a system for performing a desired subsea hydrate drilling operation, comprising a vessel, a service apparatus for performing the desired subsea operation; and a modular support apparatus mounted on the vessel and supporting the service apparatus. The vessel would be equipped with a position-maintaining device. The service modules may be selected from the group consisting of hydrate drilling apparatus, perforating apparatus, acidising apparatus, fracturing apparatus, workover apparatus, reservoir stimulation apparatus, wireline apparatus, coiled tubing apparatus, or snubbing apparatus. All these modules would add flexibility to the hydrate exploitation system.

4.2.1 Detailed description of the design

Referring initially to Figure 46, the figure depicts a vessel afloat on the sea surface. The vessel is equipped with a derrick capable of performing one or more desired hydrate well operations.

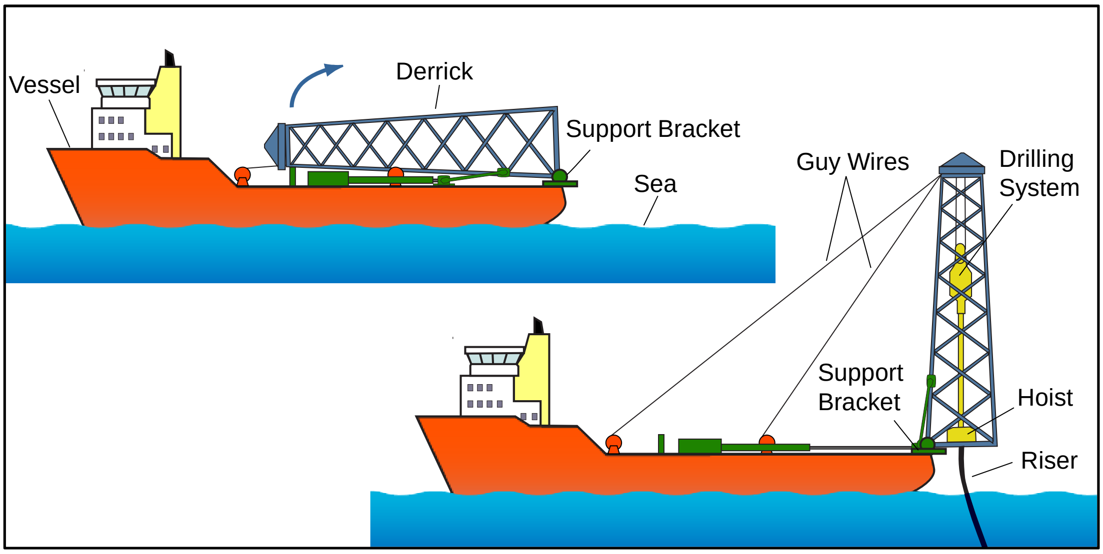


Figure 46: Vessel showing derrick being raised into an operational position (44)

The hydrate drilling operations that can be performed by the vessel derrick include, but are not limited to, slimhole drilling, tubing make-up and running, subsea tree installation, perforation, acidising, fracturing, workovers, reservoir stimulation, wireline operations, coiled tubing operations, and snubbing.

The vessel can be any vessel that has the capacity to support the desired hydrate operation. Thus, depending on the operation, suitable vessels of opportunity include, but are not limited to barges, including lay barges, bulk carriers, cable ships, container ships, ice breakers, multi purpose vessels and platform service vessels. The variety of vessels that can be used in the present invention increases the number of ships that can be considered for a given operation and eliminates the need for a drill ship or drilling rig, of which there are relatively few. In turn, this reduces the costs associated with hydrate drilling, subsea completions and interventions.

In one option, the vessel may include a support bracket or the like, to which derrick may be pivotally mounted. The mast is preferably in a horizontal or near-horizontal position during transport, and is rotated as indicated by the arrow in Figure 46 into a vertical position, after the vessel has arrived at the target location above a well (not shown) on the seafloor. Once the rig has been rotated into a vertical position, it may be supported by a bracket and by guy wires or any other suitable support mechanism. In the operating position, the rig extends off the stern of vessel, with sufficient clearance to allow the desired well operation to be performed. While the rig is shown mounted at the stern of vessel it will be understood that it could alternatively be mounted on a side or at the bow of the vessel, or above a “moon pool”, if desired. For the hydrate operation, the derrick may be outfitted with a hoist and/or various other systems that may be needed to perform the desired operation via riser.

Referring now to Figure 47. This shows the vessel adapted for use with a coiled tubing system. The coiled tubing system would be mounted on a skid and will comprise a coiled tubing injector head, reel and supporting equipment.

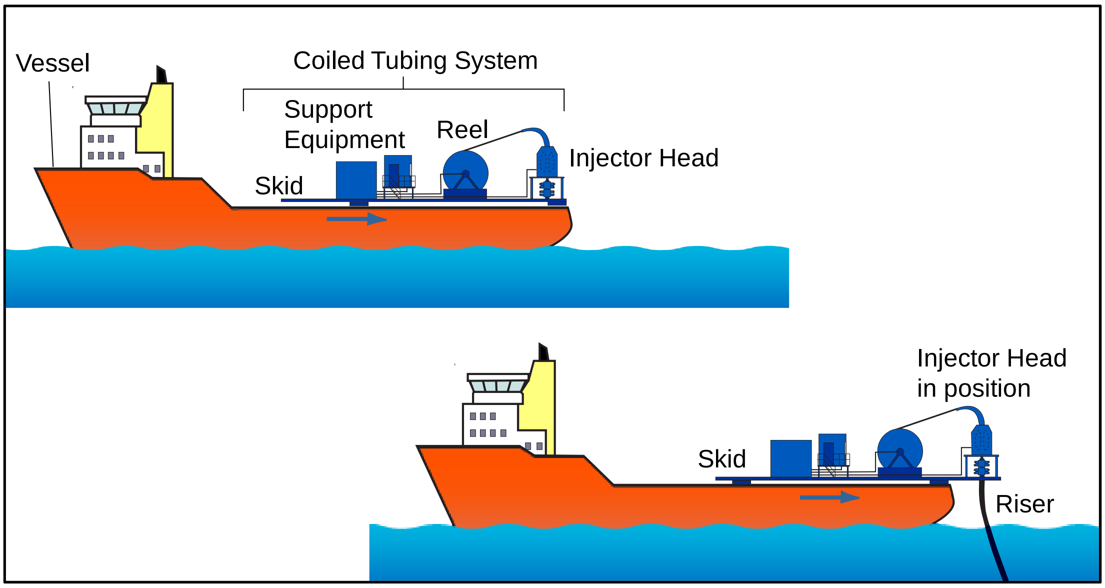


Figure 47: Vessel with skid mounted injector head for coiled tubing operations (44)

As shown above, once the vessel has reached the target location above a well (not shown), the skid is moved laterally (as indicated by arrow) until injector head is clear of the vessel, after which coiled tubing can proceed in a conventional manner via the riser or through open water.

If a derrick is unsuitable for a particular kind of vessel (due to loading or deck space availability for example) then an alternative option includes a support structure that can be substantially flattened for transport and erected for use once the vessel has arrived at the target location.

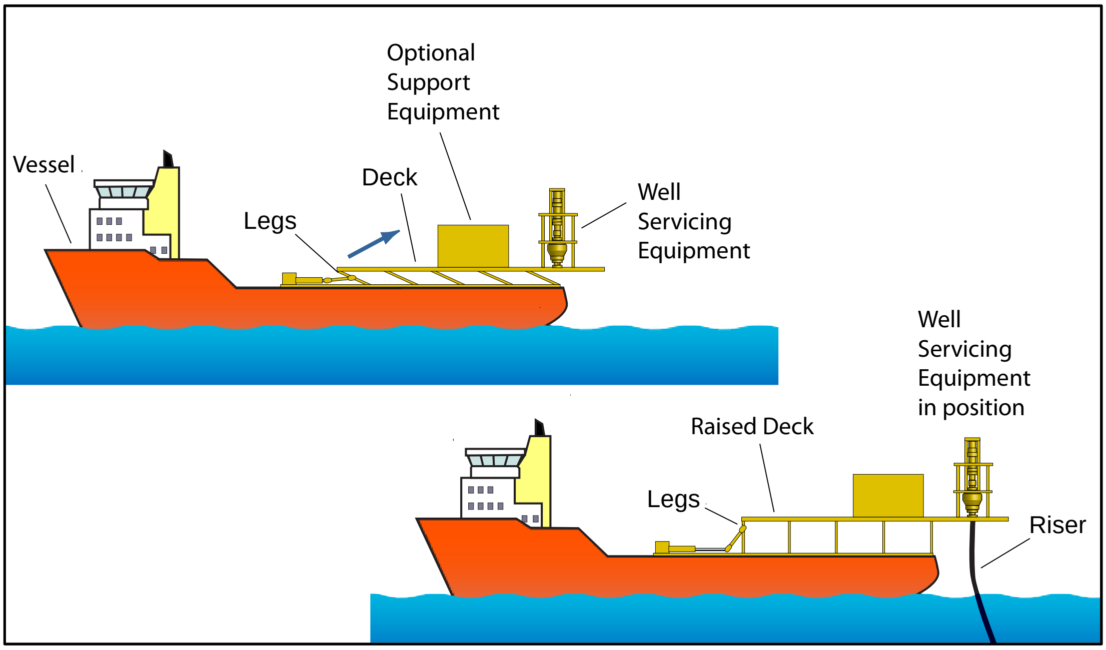


Figure 48: Vessel with on-site erectable support structure (44)

For example, referring to Figure 48, a structure may include a deck supported on a number of legs and supporting well equipment and optional support equipment. The support legs are lowered, or are substantially horizontal during transport. Once the vessel has arrived at the target location, the structure is erected as indicated by arrow and the legs are rotated and locked in a vertical position for well work, which is carried out via the riser.

Referring now to Figure 49, another option for the design comprises a buoyant platform that is held in place by two or more vessels. Each vessel is connected to the platform by at least one line, and is preferably equipped with a position-maintaining system (not shown).

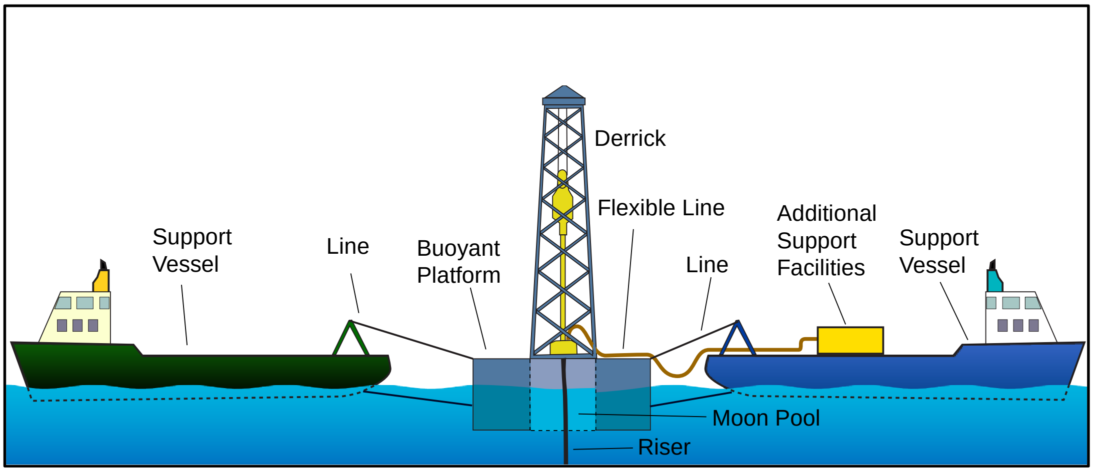


Figure 49: Buoyant platform held in place by two vessels (44)

The platform preferably includes a moon-pool extending through the deck, which provides protected access to the sea from the surface of the platform. A derrick is preferably erected over moon-pool. The derrick can be transported to the well site aboard the platform, or may be erected after the platform is in position. The derrick preferably includes hydrate drilling equipment, including systems necessary for performing the desired operation(s). If desired, additional support systems can be provided on one or more of the vessels and connected to the drilling system by flexible lines. Once vessels and platform are in position at the target location, the desired operation can be carried out via the riser, or through mid water.

In each of the designs mentioned above, the hydrate drilling or well intervention equipment can be commercially available units that are preferably provided in a modular or turn-key state. By way of example only, such equipment may include automated pipe handling systems and containerised drilling rigs, such as are commercially available.

Because the subsea well equipment used in the present invention is modular and can be readily transported and assembled, and because the vessel is a vessel of opportunity, use of a system in accordance with the present invention greatly reduces costs and increases flexibility in subsea hydrate operations.

5 Discussion and Conclusions

The aim of the research was to provide methods and equipment designs to improve technical methods and aid the economic justification for exploitation of natural gas (methane) from oceanic marine hydrate reservoirs.

The exploration and development costs using conventional subsea well and project engineering equipment and methods, will not allow this potentially huge hydrocarbon resource to be brought to market.

There are substantial global deposits of permafrost and seabed methane gas hydrates. The volume of methane gas trapped in these methane gas hydrates is calculated to be at least twice the volume of current global reserves of oil & gas, as reviewed by Kvenvolden (17), 1993.

Although validation of this number has as not yet been established by SEC resource classification methods, it is very possible from the literature reviews detailed earlier that the amount of methane trapped in hydrate is significant, but so far the information is of a qualitative nature and much more drilling, logging and resource characterisation is required before we can legitimately describe these resources as bookable reserves, as defined by Securities and Exchange Commission (SEC) guidelines.

However, if we consider the worldwide estimate of methane in methane hydrates as being 700,000 Tcf against current conventionally recoverable methane 8,800 Trillion cubic feet (Tcf). Even if 1% of gas-in-place in hydrates is recoverable it is equal to 2,000 Tcf.

Whilst the global hydrate deposits are plentiful, and the volume of methane gas associated with them is massive, the drilling and well logging projects conducted so far has identified that the hydrates are deposited in vastly different environments of depositions and in different accumulations.

Technical and economic viability with these environments of deposition will be determined by reservoirs with suitable rock and petrophysical properties e.g. porosity, saturation, permeability derived from log analysis and laboratory analysis, combined with flow rate sustainability, ultimate recovery factors, reservoir volumetrics and proven techniques for extraction of the methane gas to market.

Subsea wells have a traditional arrangement of wellhead, xmas tree and manifold, the tree and manifold also have attached the controls module and any instrumentation termination from pressure, temperature, and flow instrumentation within the surface or subsurface equipment. The complexity of the subsea architecture has continued to increase and, with it, the weight and size of the respective components. Some anecdotal evidence in circa 1980 in the North Sea dual bore subsea trees weighed a little over 14 tonnes. Today in deepwater they are installing subsea trees that weigh almost 50 tonnes and have the same or similar pressure and temperature ratings as those installed in the 1980’s. This weight increase brings with it a huge cost increase and a deepwater tree is currently costing circa $5 million per unit.

Reviewing this brought the realisation that the subsea architecture, tree wellhead and manifold have evolved from land systems and have steadily increased in complexity and cost and need radical change in methane gas hydrate exploitation. The subsea hydrate architecture invented (patent application 0908018.5) will remove the need for any subsea tree system totally, whilst at the same time provide improvements in environmental and personal safety. The system has additional design features in that it isolates the well from flow for intervention operations, provides a collection point for gas escape around the wellhead (residual risk as methane gas is dissociated from the hydrate and near bore stability is affected), allows variable setting of the wellhead position to aid top-hole drilling and minimise directional variation in the unconsolidated top hole section, integrates in modular fashion services, and ancillary systems, that will allow removal of water and sand from the well bore effluent and provide functionality to pump this effluent to disposal wells within the hydrate system.

The hydrate exploitation design proposed will be a simple seabed mounted system. It will be capable of being deployed in a water depth ranging from 500m to 1500m, depending upon site location and topography. The slim hole system is chosen as it will offer a simpler and, hence, more cost effective means of deploying the system from a floating hoist – vessel of opportunity smaller than a more expensive semi submersible drilling rig. The device is original in that it deviates from standard oil and gas well engineering and subsea apparatus.

The research also helped derive the concept of the use of a so called “Vessel of Opportunity” in deepwater hydrate operations. The use of a conventional drillship type vessel would never be economic, so an alternative had to be designed.

The driver, as in all development of safely exploitable hydrocarbon resource, will remain financially rewarding. This is namely value derived from investment committed. These methane gas hydrates are deemed important as a future energy resource, and Nations are looking at this resource as a means to provide methane gas to contribute to their demands for energy consumption.

To date, the world has not been able to bring this energy resource to market because the understanding of the volumes and cost of exploitation exceeds the gas price achievable. Until this cost for exploitation can be substantially reduced, gas hydrates will remain dormant as a world energy resource, and continue to be regarded as a safety hazard for conventional drilling hazards or an environmental hazard for global warming.

Nations of the world such as the United States of America, Japan, Canada, The European Union (on behalf of member states), Korea and India are investing heavily in research and development to gain a better understanding of the gas hydrate energy source.

It is concluded that the ongoing scientific research will provide the enhanced understanding of the geology, petrophysics and geosciences but only with the application of new innovative well technology and techniques that radically reduces the cost of development for methane hydrate exploitation, will it be possible to bring this important energy source to market.

5.1 Originality of research and proof of original knowledge in the field

The research confirms that the cost model using conventional technology is prohibitively high, and evaluation of cost for a conventional deepwater well has identified three predominant items that have to be radically changed to make a difference in any cost of construction model. This led to explored options for the reduction of cost by application of invented technology and or application of invented techniques, within the marine deepwater hydrate environment.

Item 1 is the cost of the subsea architecture namely manifolds, tree and ancillary services. These costs are nearly 25% of any deepwater development.

Item 2 is the rig costs currently conventional semi submersible costs for deepwater applications are at an all time high, even in this recessionary period and costs of nearly $500,000 (US) per day is a regular occurrence in the deepwater business environment for deepwater semi submersible rigs. Rig costs are almost 50% of any deepwater development

The main deliverable from this research has been the filing of one patent application (43) and progress to patent filing for the other (44). The designs in these patents are deemed to have application to conventional oil and gas exploitation as well as the future hydrate exploitation business.

5.2 Future work

5.2.1 Subsea system – Methane Gas Hydrate Exploitation System

The subsea system will require a prototype device to be built and tested with in the load conditions expected in the methane gas hydrate wells.

The system will need to be light weight to allow situation adjacent to a methane gas hydrate field that during production shall experience compaction problems as the gas is dissociated from the sedimentary structures. The light weight development will be achieved by the utilisation of composite materials.

It would be preferred if this system, or components of this system, are tested in a conventional subsea oil or gas fields to gain knowledge and experience for the system before it is deployed in earnest on a marine methane gas hydrate field.

5.2.2 **Floating Hoist – Vessel of Opportunity**

Testing of the floating hoist concept will begin in 2012 using an existing vessel being constructed in Indonesia that can be undertaken for conventional wells workscope like top hole drilling and completion installation. This will be a vital testing ground for the proof of concept.

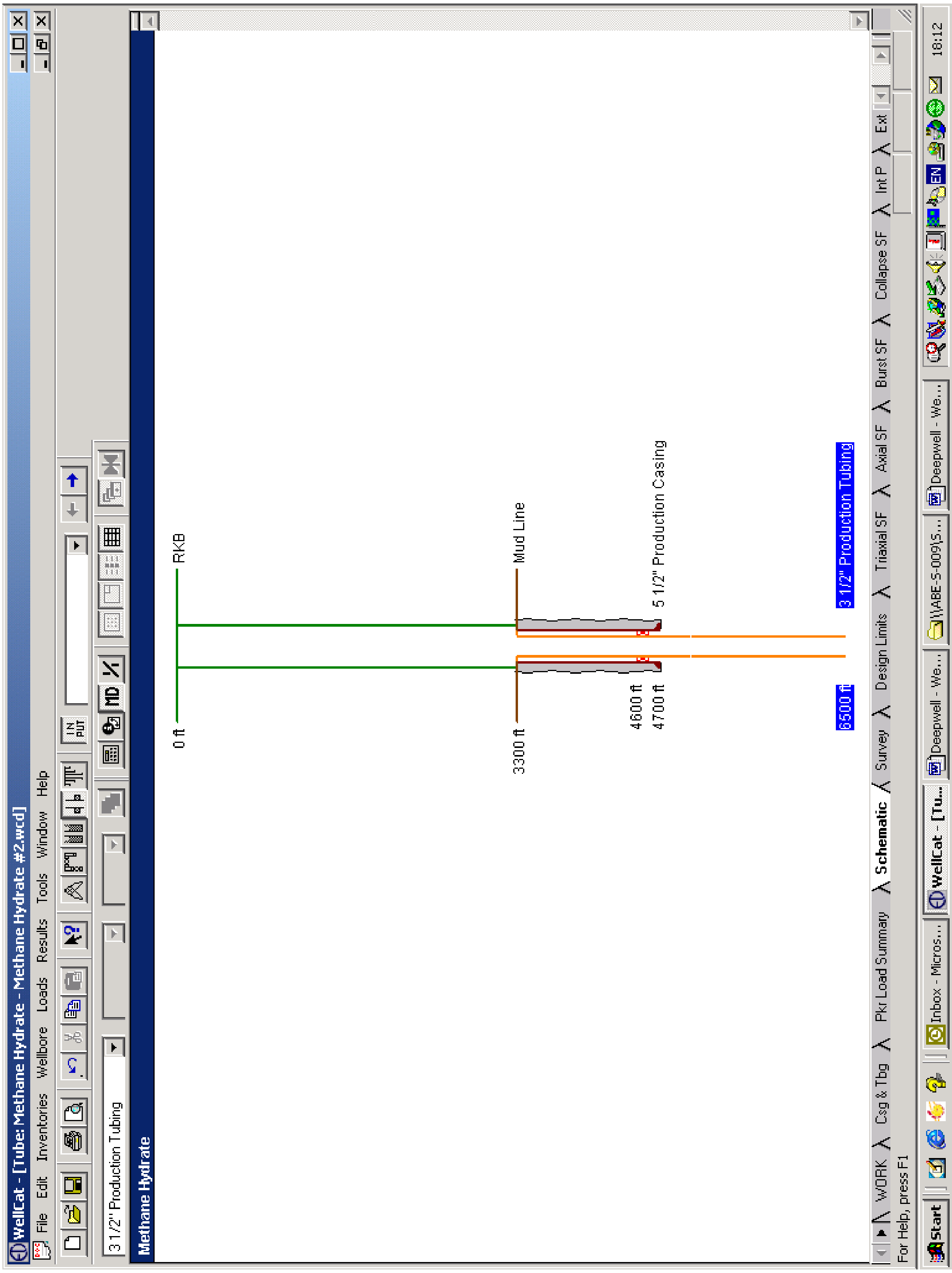
The next stage will be to further reduce costs by placing these construction type systems on a “Vessel of Opportunity”, making unit development cost attractive for exploitation of smaller oil or gas accumulations and also for methane gas hydrates.

5.2.3 **Subsea Drilling System - Subsea topdive**

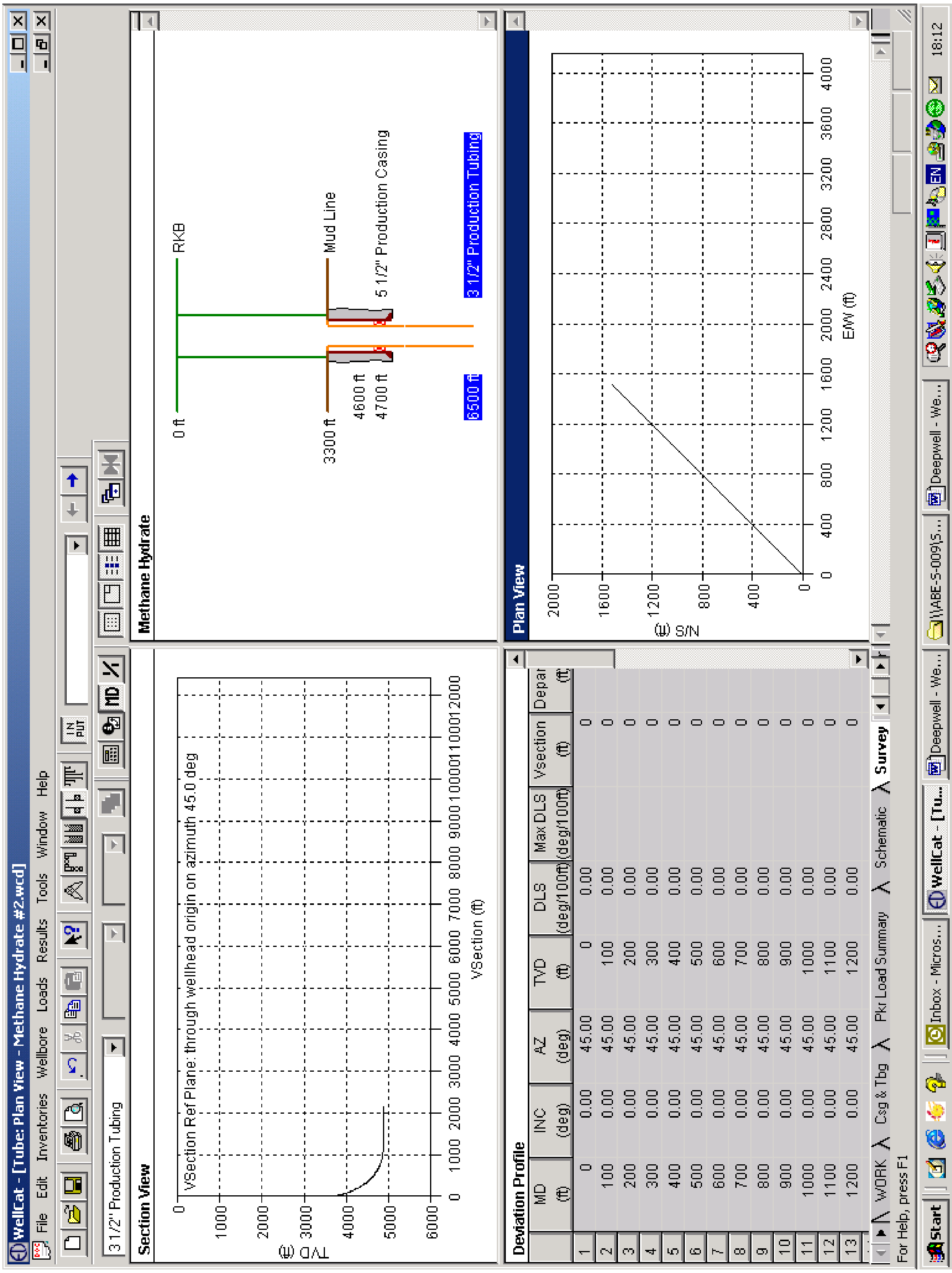
The subsea topdrive system will provide an efficiency in drilling time in methane gas hydrate fields where high density grid drilling will be the required drilling practice.

The subsea topdrive will need to be designed, a prototype built and then used in submerged trials to confirm suitability. Thereafter the system will be required to undergo full deepwater trials to confirm suitability for methane gas hydrate drilling.

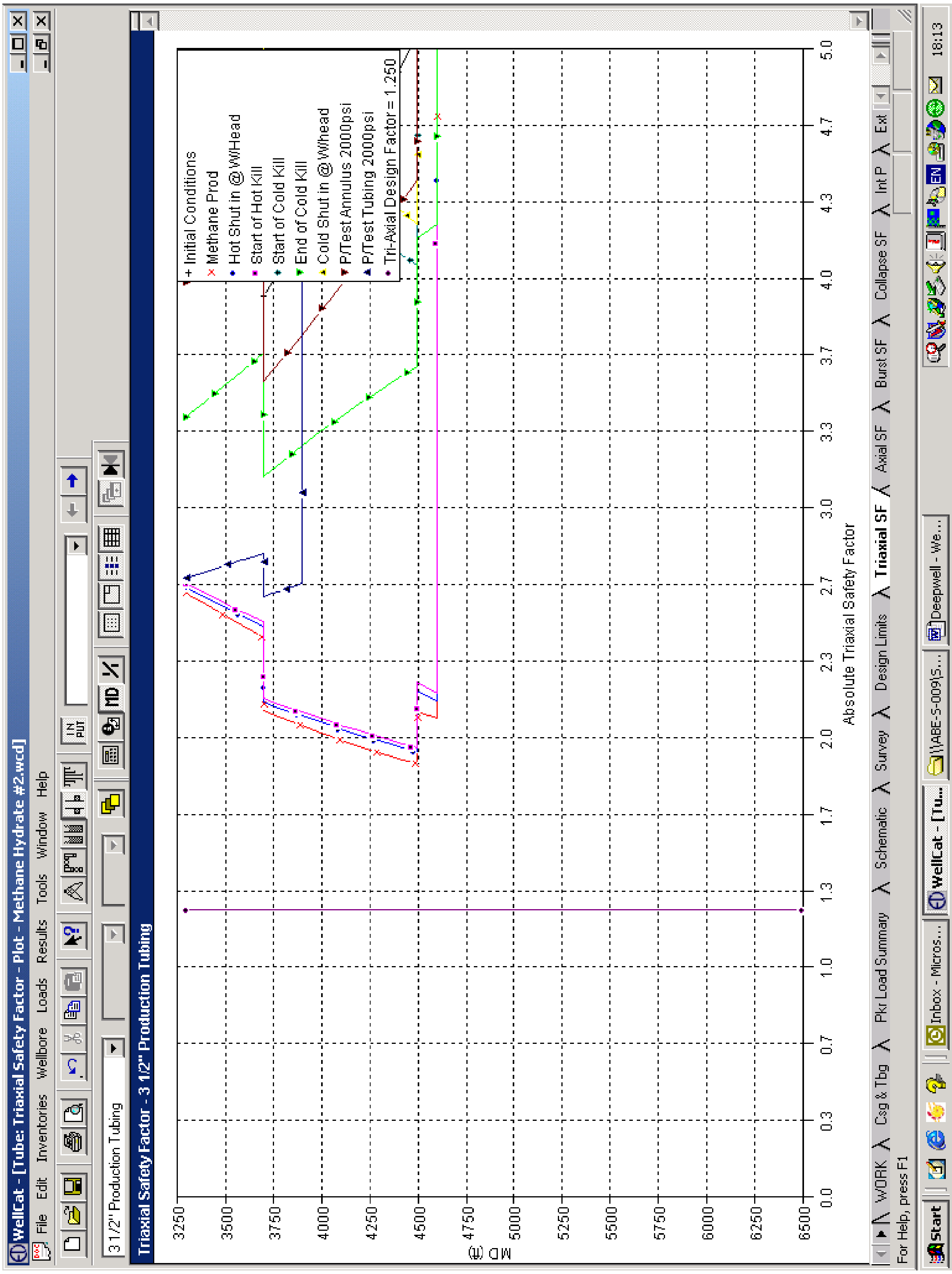
6 Appendix 1



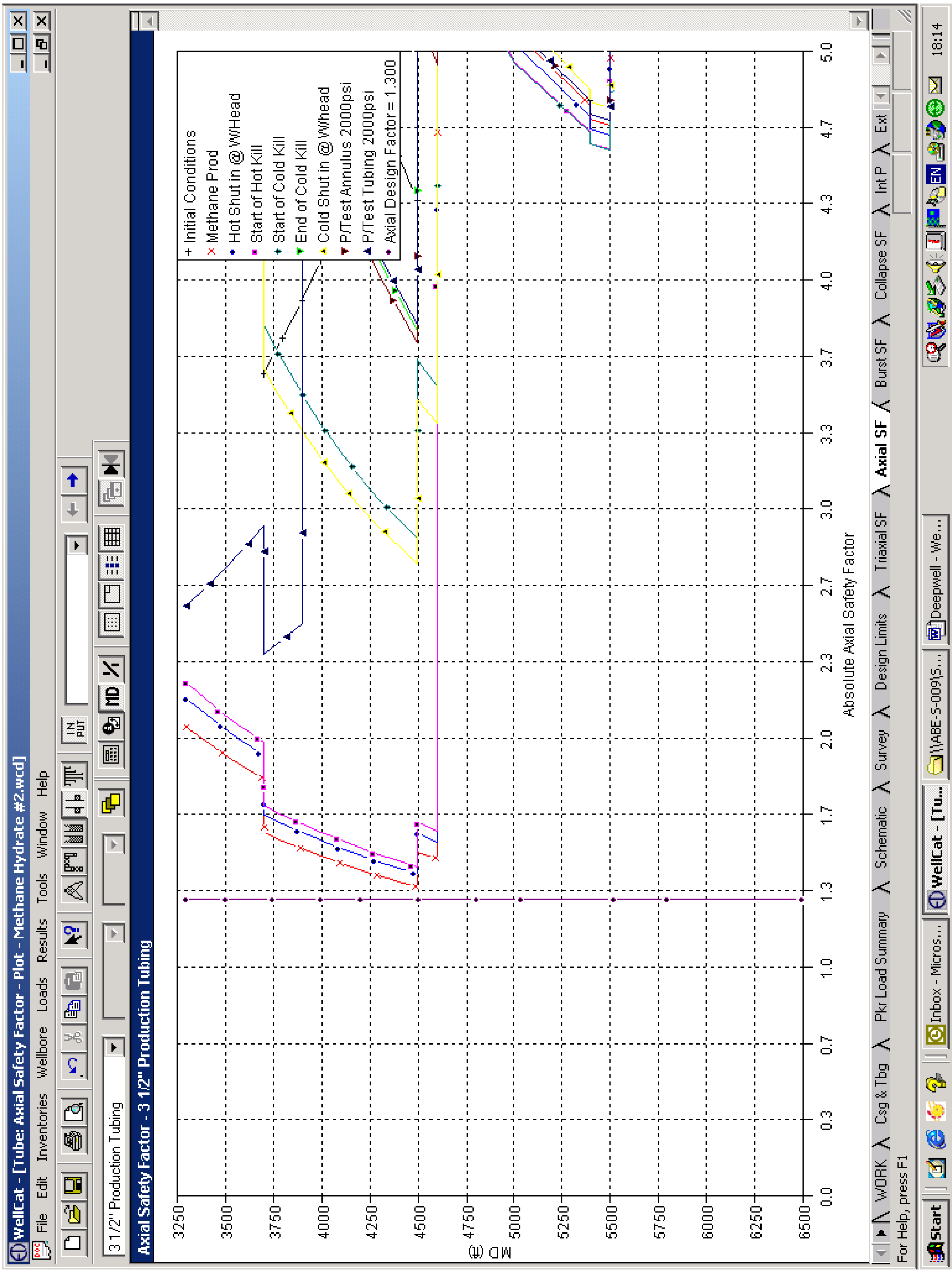
Well schematic to depth of the hydrate production zone.



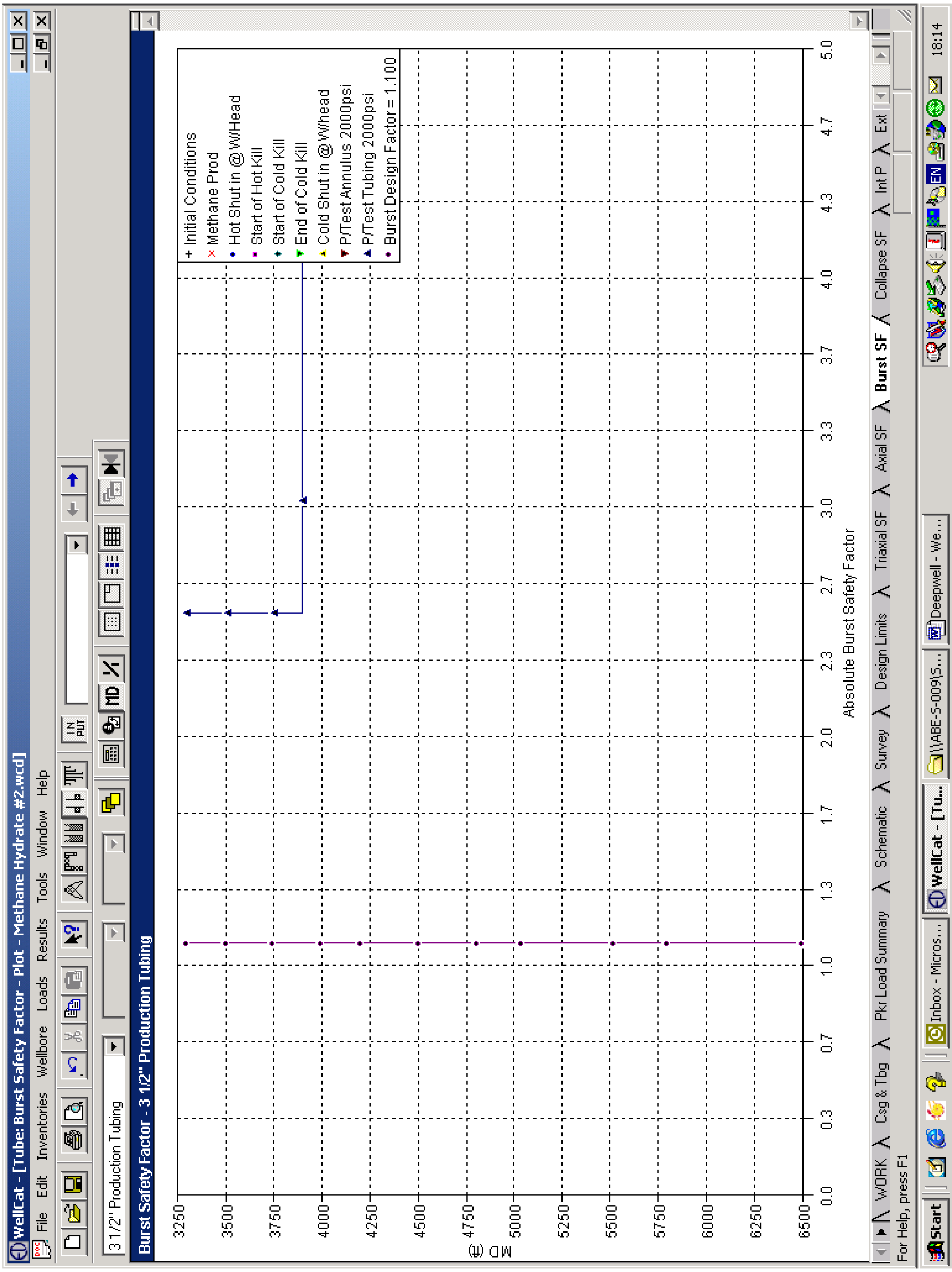
Deviation schematic showing typical well deviation profile.



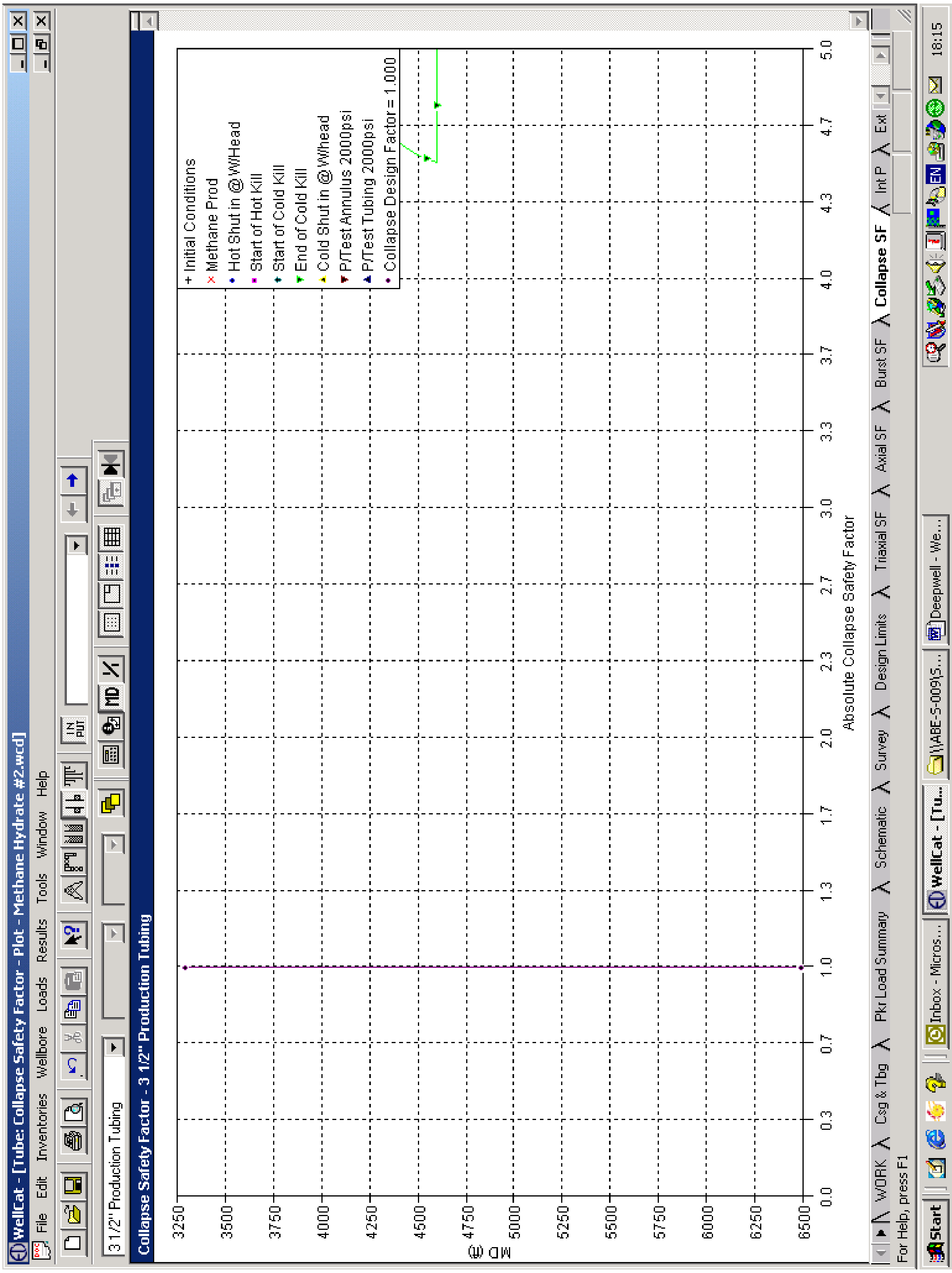
Triaxial load conditions versus limit for safety factor.



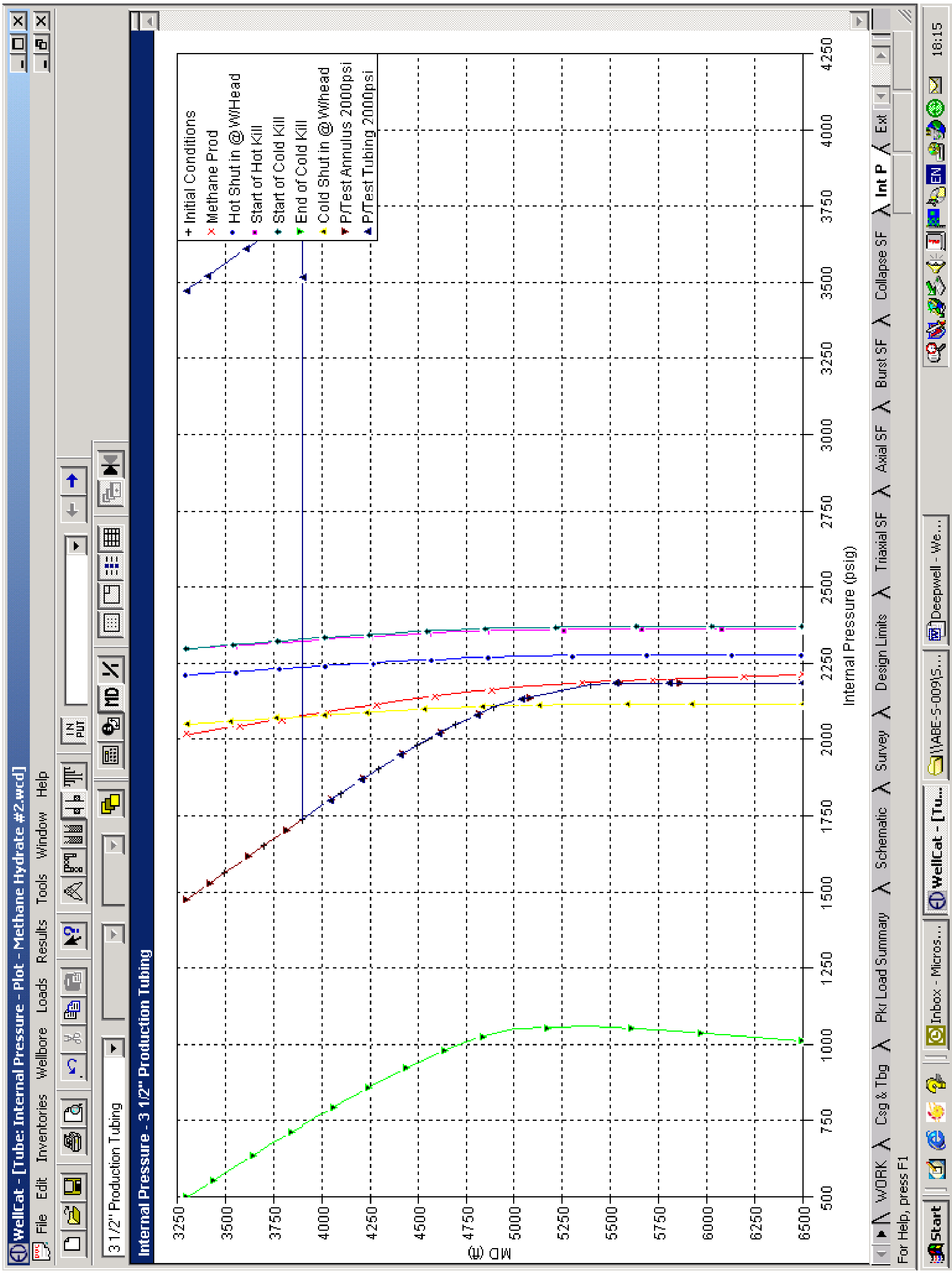
Axial load conditions versus limit for safety factor.



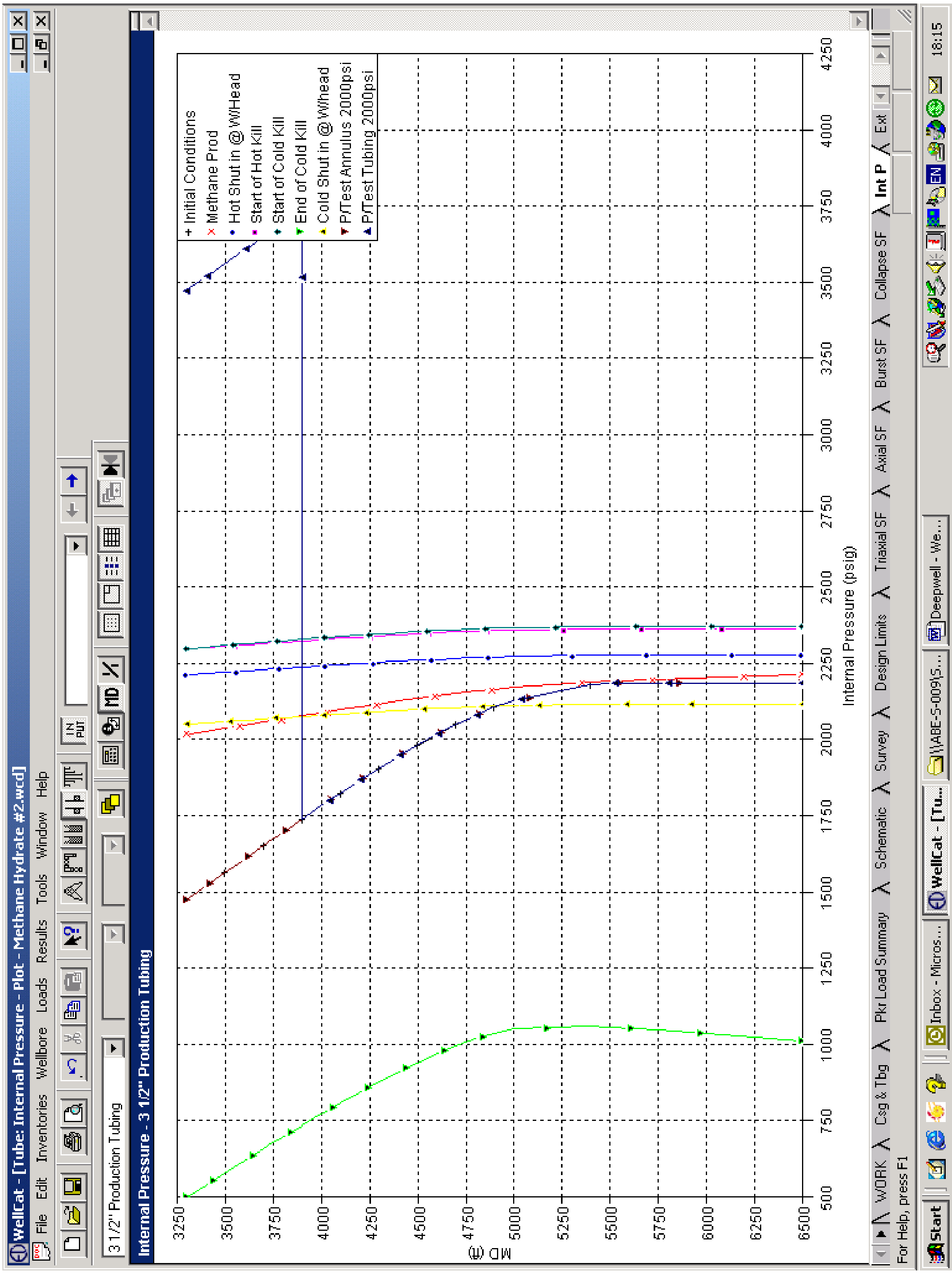
Burst load conditions versus load for safety factor.



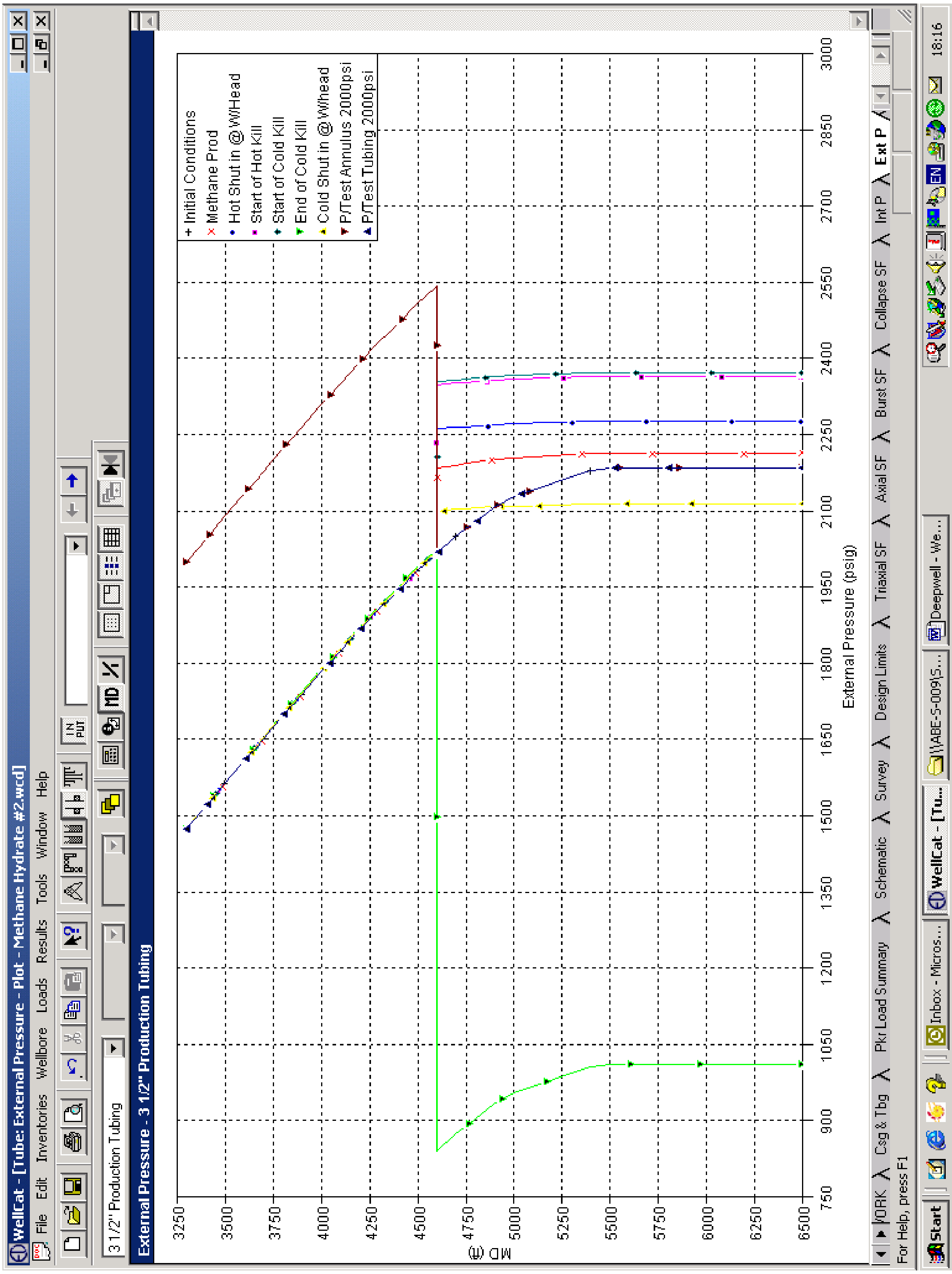
Collapse load conditions versus load for safety factor



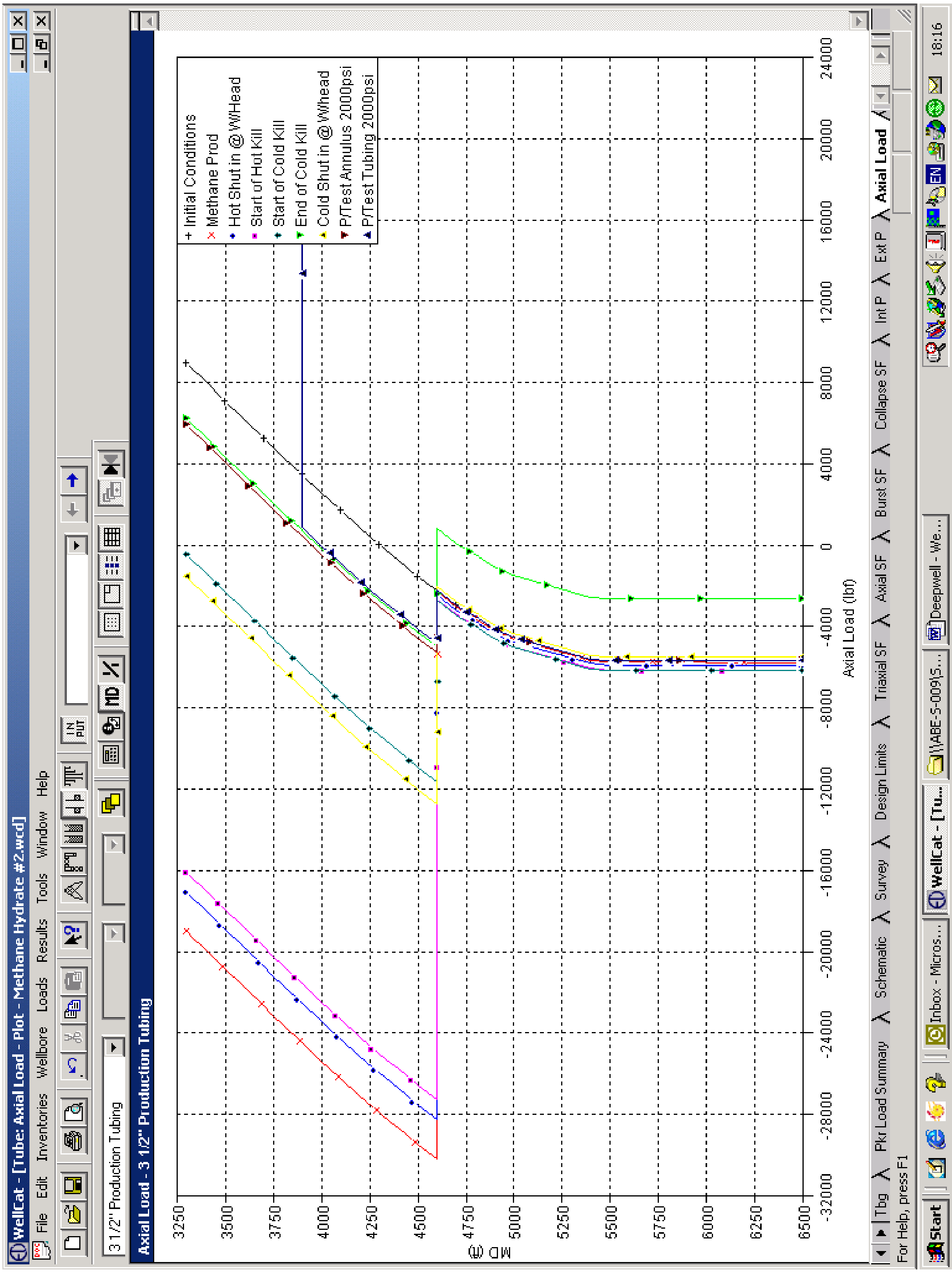
Internal pressure load conditions during life of well.



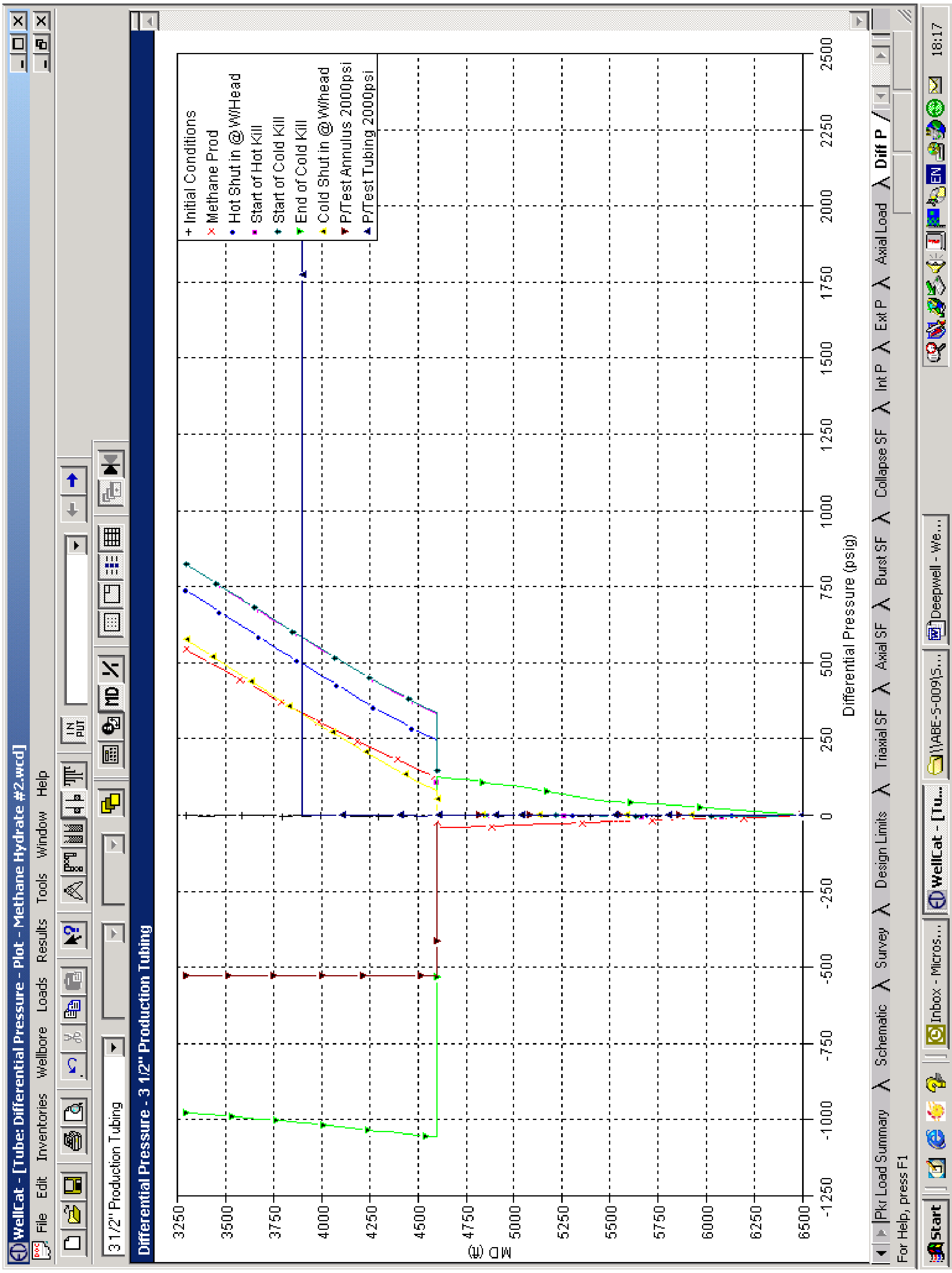
Internal pressure load conditions during life of well



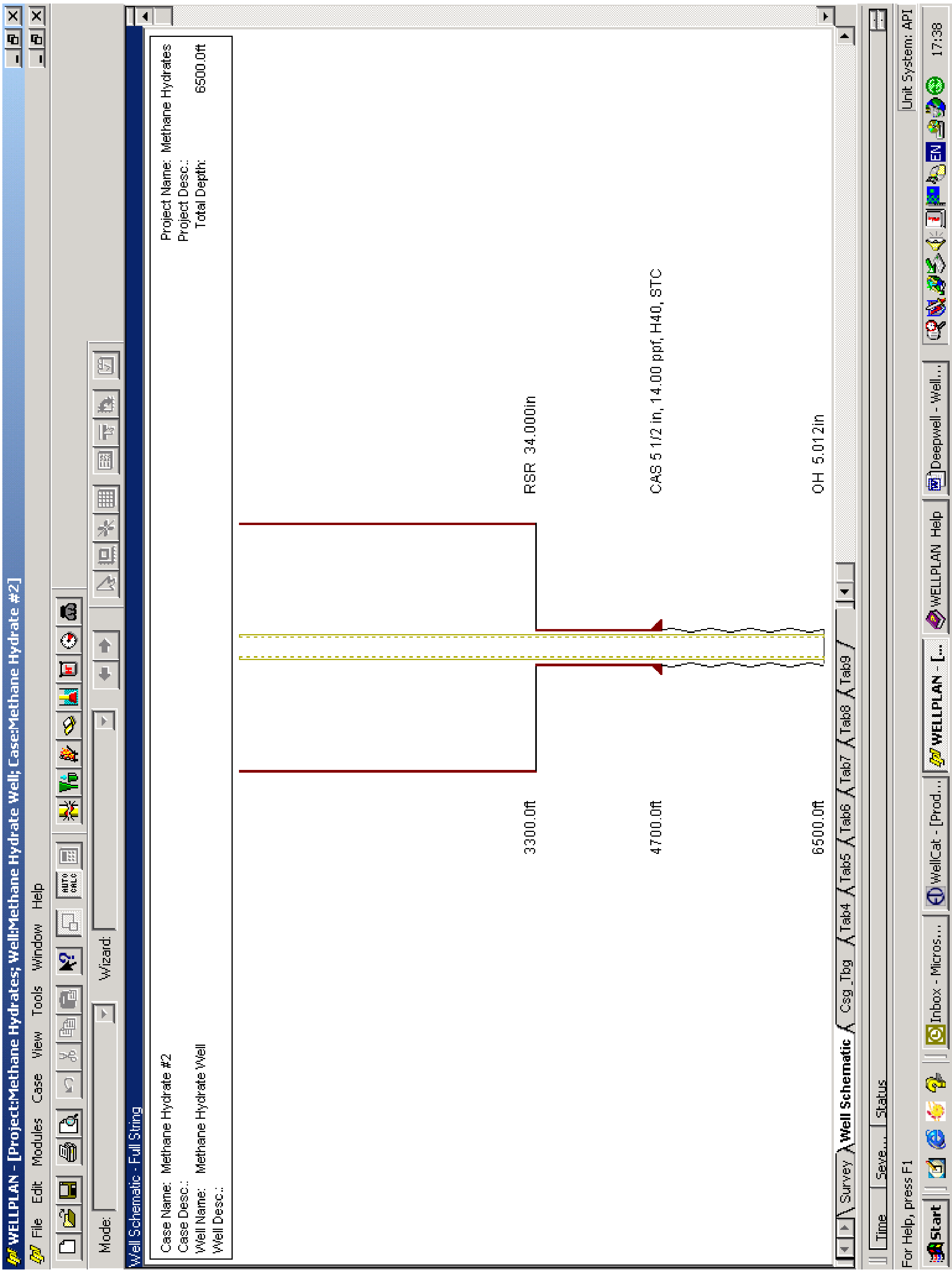
External pressure load conditions during life of well.



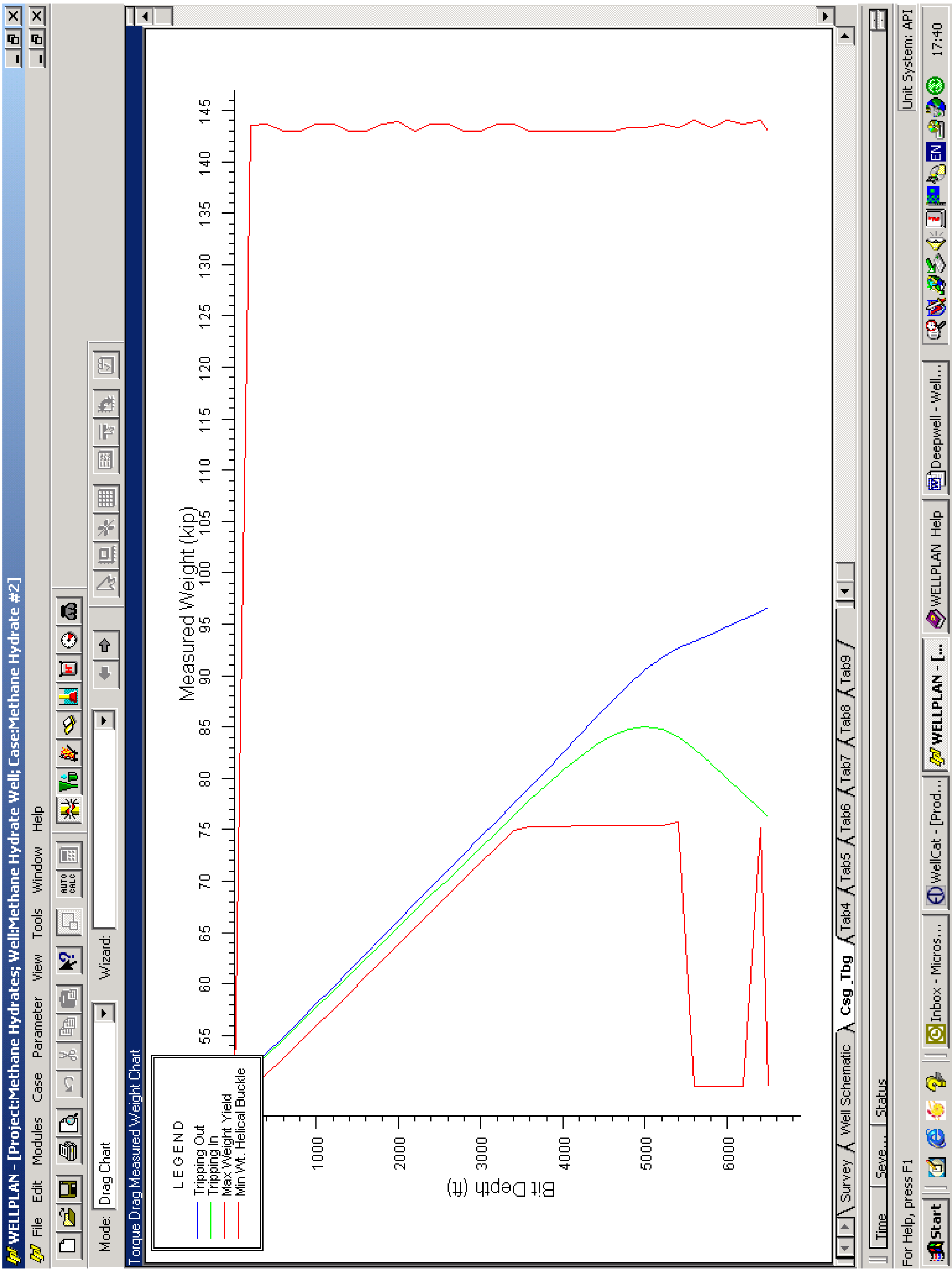
Axial loads during construction and life of well.



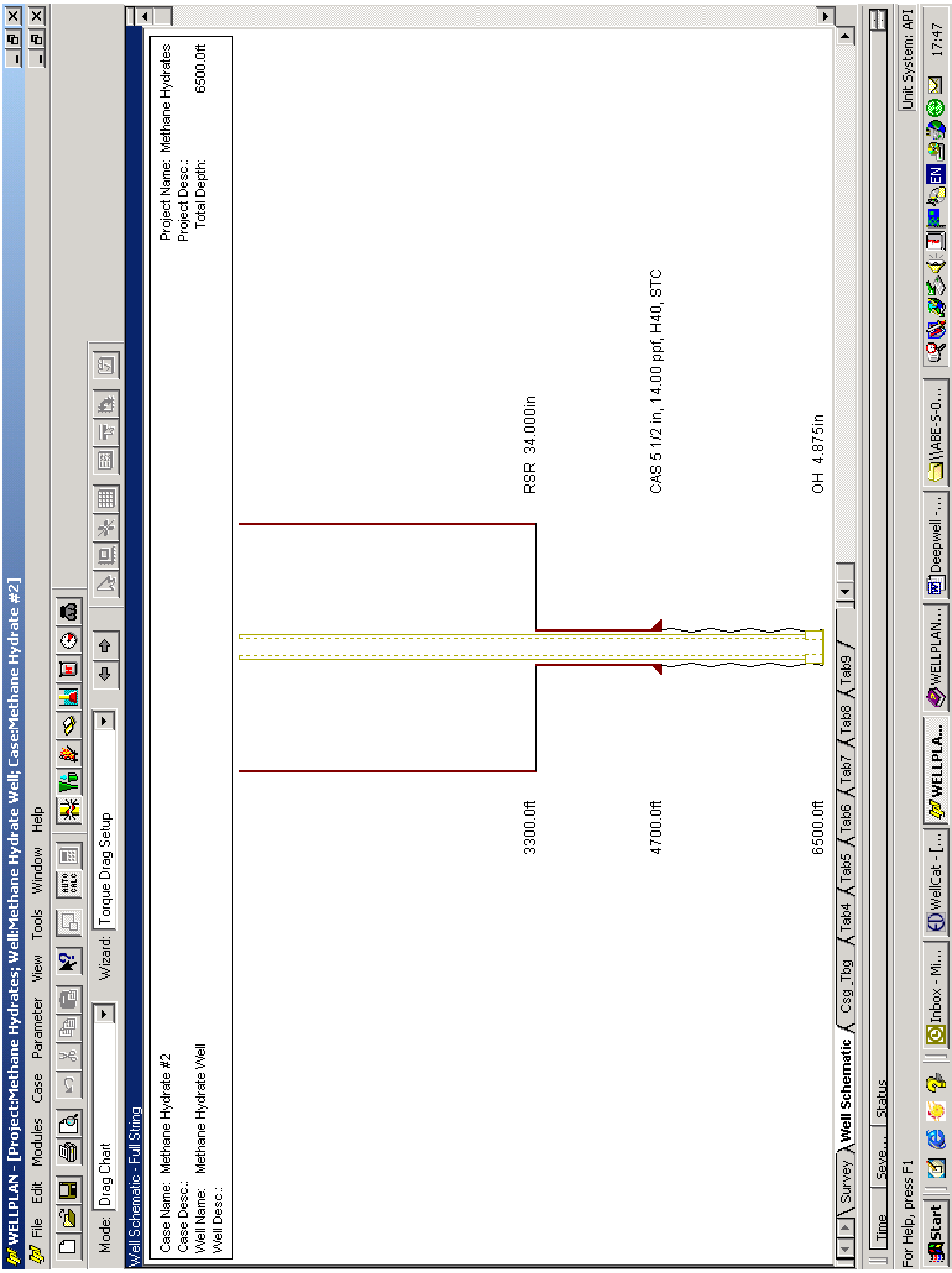
Differential pressures during construction and life of well.



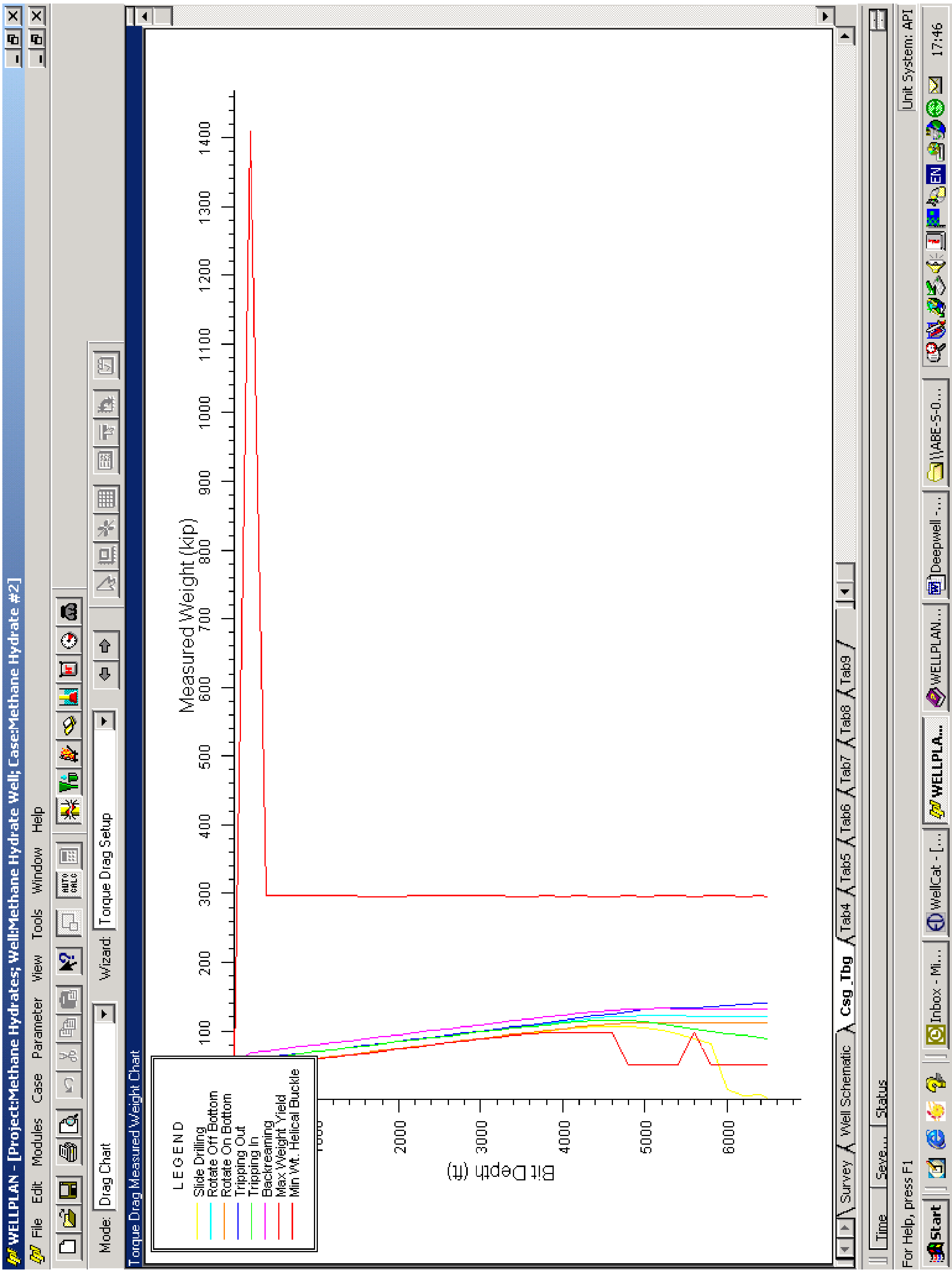
Schematic of completion running



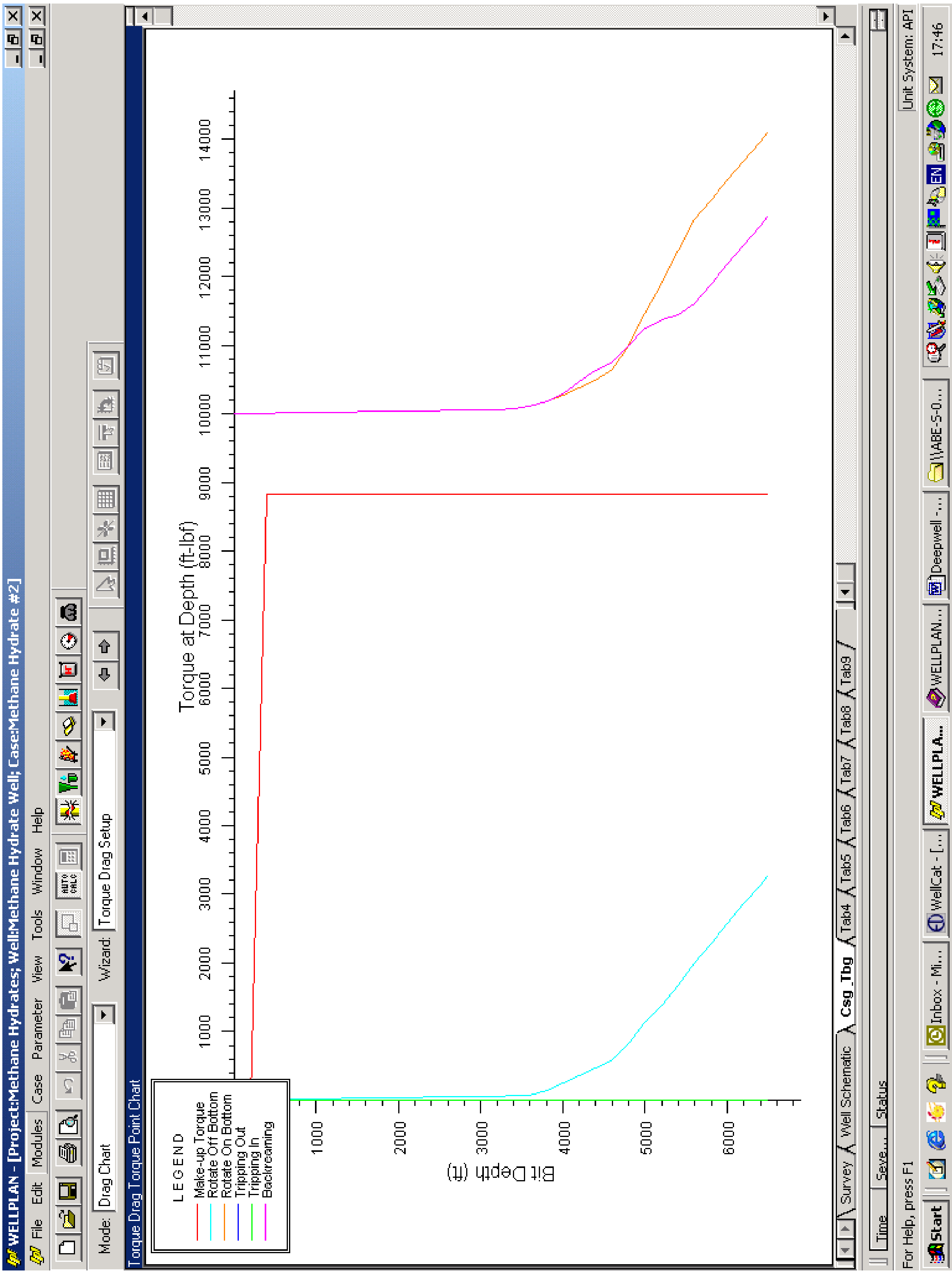
Drag weight of completion running.



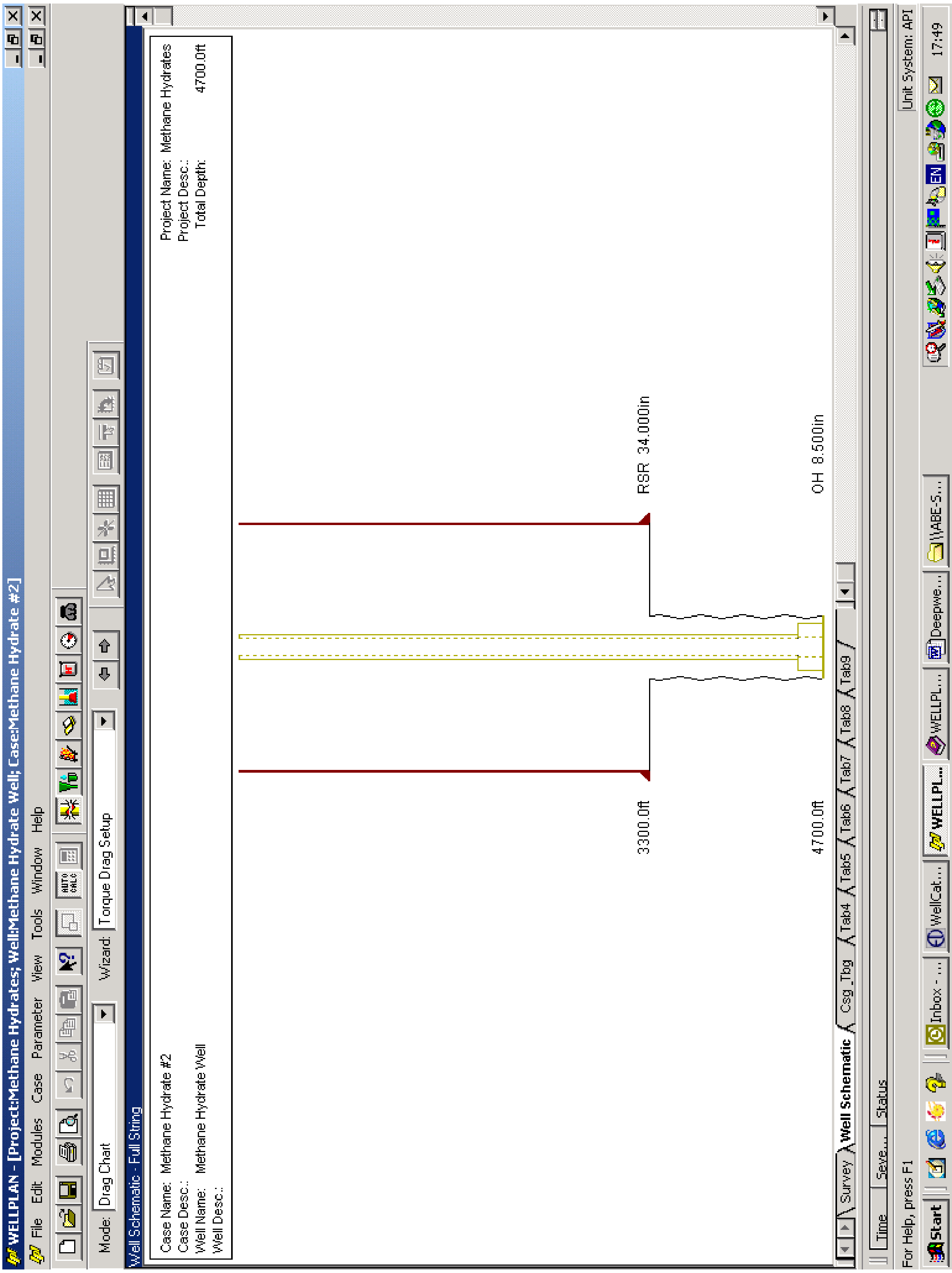
Schematic for drilling 4 7/8” hole.



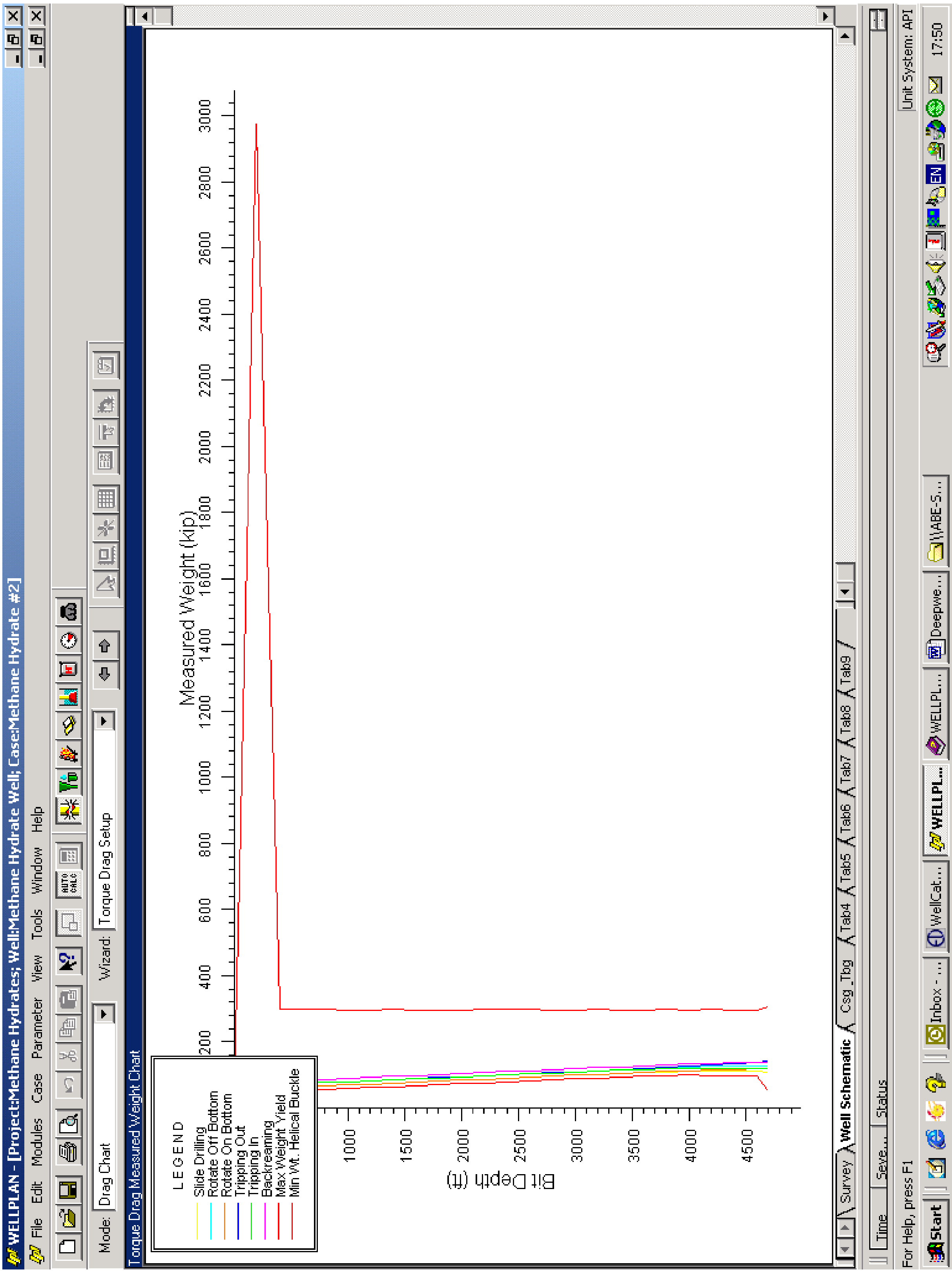
Drag loads for drilling 4 7/8” hole.



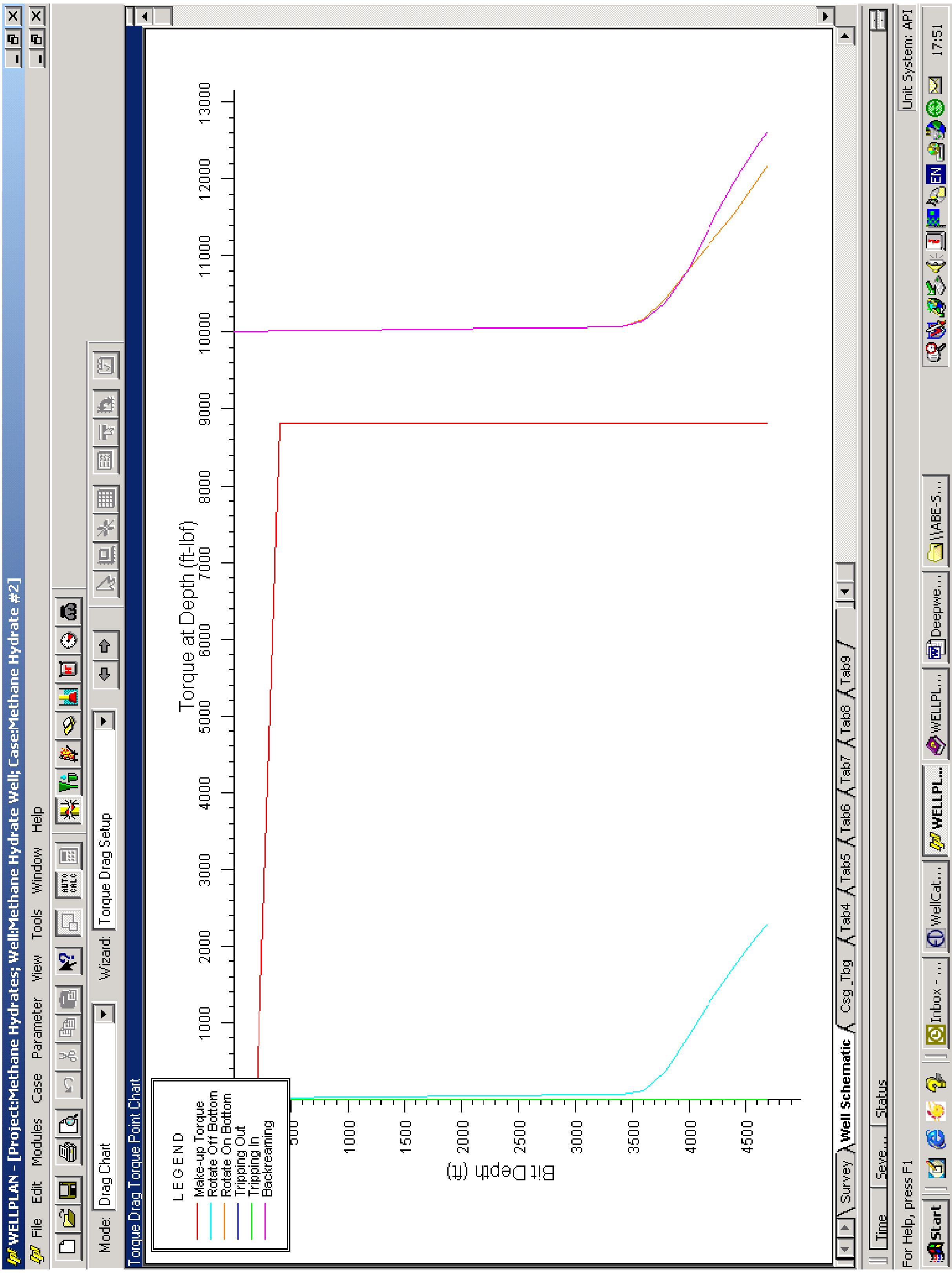
Torque loads for drilling 4 7/8" hole



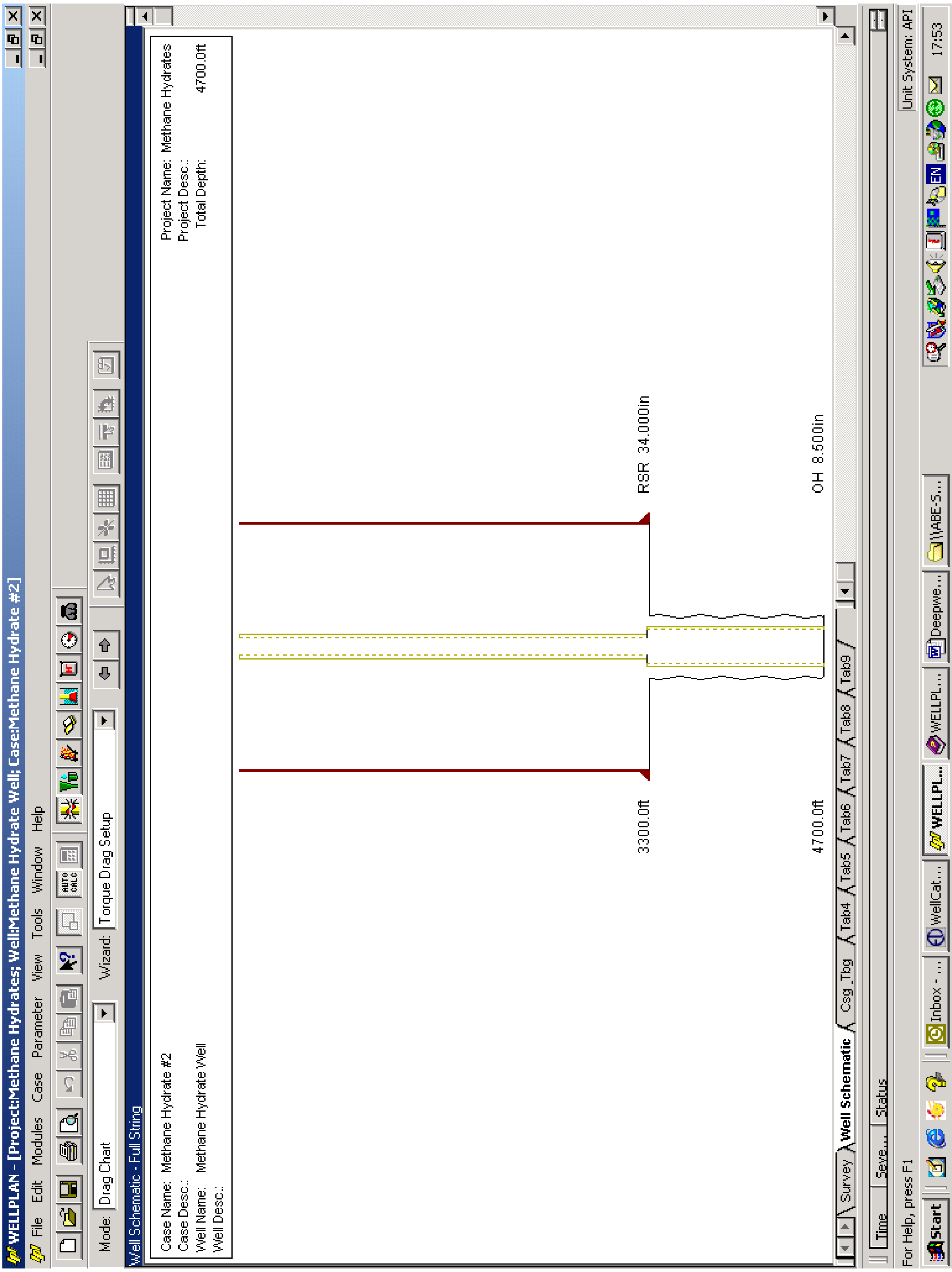
Schematic for drilling tophole



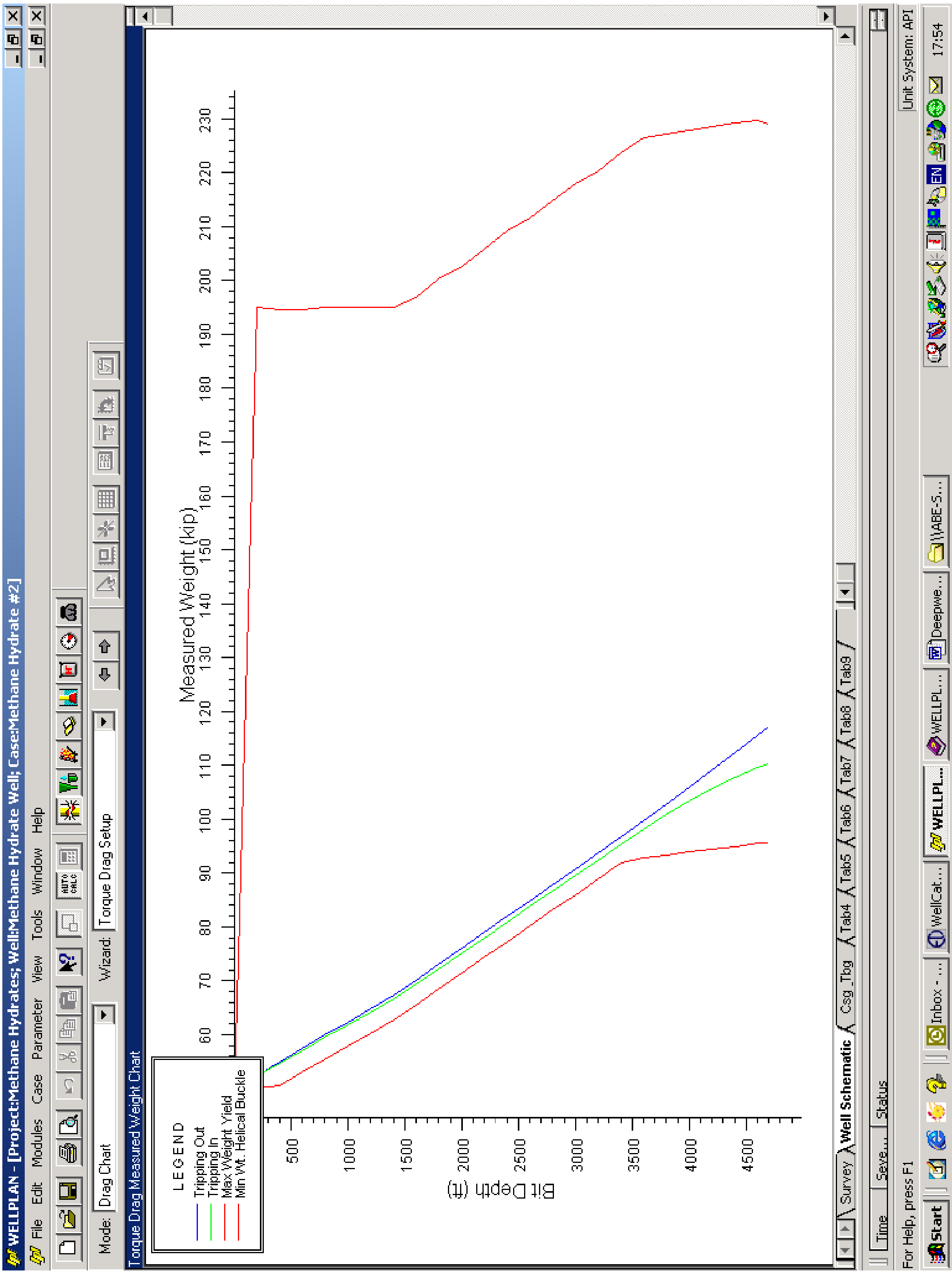
Drag load for drilling tophole



Torque loads for drilling tophole



Schematic for running production casing



Drag loads for running surface casing

7 Glossary

Term	Definition
Annulus	The space between the wellbore and casing or between casing and tubing, where fluid can flow.
Blow out preventer	Hydraulically or mechanically actuated high pressure valve installed at the wellhead to control pressure within the well.
Blowout	Uncontrolled flow of gas, oil, or other well fluids from a well during drilling due to formation pressure exceeding the pressure exerted by the column of drilling mud.
Bottom Hole Assembly	The lower portion of the drillstring which is used to provide force for the bit to break the formation, and to provide the driller with directional control of the well. The assembly usuallyincludes a mud motor, directional drilling and measuring equipment, measurements-while-drilling tools and logging-while-drilling tools.
Caliper logs	Caliper logs are usually measured mechanically with multi-finger calipers. The tools measure diameter at a specific chord across the well. Drilling engineers use caliper logs as a qualitative indication of both the condition of the wellbore and the degree to which the mud system has maintained hole stability.
Cementing	Cementing operations are usually undertaken to seal the annulus after a casing string has been run.
Coiled tubing drilling	The use of coiled tubing with downhole mud motors to turn the bit to drill or deepen a wellbore section.
Fish	Anything left, or lost in a wellbore.
Fishing	The use of tools, equipment and techniques for the removal of junk, debris or fish from a wellbore.
Gas cut mud	A mud that has gas (air or natural gas) bubbles in it, gas-cut mud

	has lower density than a mud not cut by gas.
Hole cleaning	Circulating drilling fluid to transport cuttings and other fragments out of a wellbore.
Kicks	A kick is an unexpected flow of fluid during an operation due to the pressure in the wellbore being less than that of the formation fluids, thus causing flow from the formation in to the wellbore.
Killing (a well)	The act of bringing a well under control which has blown out or is threatening to blow out; also applies to the procedure of circulating water and mud into a completed well before starting well intervention operations.
Leak off test	The purpose of a leak-off test is to determine the strength the reservoir formation. During the test, the well is shut in and fluid is pumped into the wellbore to gradually increase the pressure that the formation experiences. At a given pressure, fluid will leak-off in to the formation, either through permeable paths or by creating a space by fracturing the formation.
Logging Whilst Drilling	The measurement of formation properties during the drilling of the hole, through the use of tools integrated into the bottomhole assembly.
Measurement Whilst Drilling	Measurements of physical properties such as wellbore pressure, temperature and trajectory during drilling. The measurements are made downhole, stored in solid-state memory for some time and later transmitted, or retrieved, to the surface.
Open hole	Uncased part of a well.
Overbalanced drilling	Drilling when the hydrostatic head of the drilling fluid is greater than the pressure of the formation being drilled.
Overhang	Surplus of supply or inventory
Overshot device	A downhole tool used in fishing operations to engage on the outside surface of a tube or tool. A grapple, or similar slip mechanism, on the overshot grips the fish, allowing application of tensile force and jarring action. If the fish cannot be removed,

	a release system within the overshot allows the overshot to be disengaged and retrieved.
Packer	A downhole device used to isolate the annulus from the production conduit.
PDC bit	A drilling tool that uses polycrystalline diamond compact (PDC) cutters to shear rock with a continuous scraping motion.
Plug	Object or device that serves to block the well such as a cement plug.
Pressure Whilst Drilling	Advancement on MWD which provides annular pressure, internal pressure and temperature measurements and aids in detecting lost circulation and flow/kicks before they happen.
Reservoir modelling	Production of a model of a reservoir. The model could include any of the geological, fluid or other characteristics of the reservoir.
Riser	A large-diameter pipe that connects the subsea BOP stack to a floating surface rig to take mud returns to the surface.
Seal Assembly	A system of seals arranged on the component that engages in a sealbore to isolate the production-tubing conduit from the annulus. The seal assembly is typically longer than the sealbore to enable some movement of the components while maintaining an efficient seal.
Slimhole (drilling)	Drilling in which the hole size is smaller than the conventional hole diameter, enabling the operator to run smaller casing, thereby decreasing the cost of completion
Squeeze	The careful application of pump pressure to force a fluid or slurry into a treatment zone.
Stuck pipe	Drill pipe, casing, or tubing that cannot be worked in or out of the hole as desired.
Topdrive	A device that turns the drillstring, consisting of one or more motors connected with appropriate gearing to a short section of

	pipe called a quill, that in turn may be screwed into a saver sub or the drillstring itself.
Total Depth	Maximum depth reached in a well.
Tripping	Making a trip; operation of hoisting pipe out of, and returning it to, the wellbore.
Underbalance drilling	Drilling with the hydrostatic head of the drilling fluid being intentionally lower than the pressure of the formation being drilled.
Undereamer	Tool used to enlarge a wellbore past its original drilled size. Underreaming is sometimes done for safety or efficiency reasons as it may be safer to drill unknown shallow formations with a small-diameter bit, and if no gas is encountered, to then enlarge the pilot hole.
Washout	An enlarged region of a wellbore, larger than the original hole, caused by failure of soft or unconsolidated formations.
Well intervention	Procedures performed after the well has been completed and production from the reservoir has begun. Well intervention activities are generally conducted to maintain or enhance the well productivity, although some applications are performed to assess or monitor the performance of the well or reservoir.

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