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Drilling Facility Design – The Value Of Operational Input

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Abstract

There are a number of international developments where new build platform drilling rigs are specified. The duration and size of the drilling program coupled with the geographic locations lead to the requirement for a permanent rig installation.

Compared to the overall development cost the rig CAPEX is usually a relatively small proportion of the project, however, when the cost of the wells is included the DRILLEX can account for between 30 – 40% of the overall project cost. Whilst the rig cost may be a relatively small percentage of the total project cost the operational efficiency of the rig will have a direct impact on the overall project economics.

During the initial conceptual engineering stages of a project it is essential that the project drivers and well designs are understood to allow a clear definition of the rig equipment sizing and functionality.

The appropriate levels of mechanization versus the impact on safety, efficiency, increased weight and reliability are areas that must be clearly defined prior to commencing detailed design.

The paper will highlight a structured approach to rig sizing and equipment selection based on a "wells up approach" taking account of recent vendor equipment developments and designs.

Introduction

KCA Deutag are executing projects for several new build platform based drilling facilities in a number of different geographic areas. Typically the drilling portion of these projects comprise in excess of 30 wells that are highly deviated and have a significant well maintenance and sidetracking requirement past the initial drilling campaign. The technical and contracting approach taken by the individual operators to specify and design the rig during the initial stages of a project is best described as variable, even though the same general concerns and issues are seen across projects.

The company HSE requirements that influence areas such as mechanization and discharge requirements can be poorly defined or interpreted, leading to ambiguity in the design intent. Where these areas are not well specified initially, it is almost inevitable that at a later stage the operations personnel start to question the rig arrangements leading to change.

The approach to rig sizing is often superficial, rigs tend to be either over or under-rated for the intended duty. The future well requirements and maximum depth capability are seldom clearly defined as a result equipment tends to be overspecified. Based on using a "wells up approach" where all the well loads are calculated and the distribution of well depths determined, we have observed that most early concept studies significantly over-size the principal drilling equipment.

There can be a tendency to specify drilling equipment based simplistically on what was seen on the last rig. In some cases this may be based on arrangements that are not applicable to the planned platform operations, i.e. the newer deepwater drillships, which have numerous capabilities such as dual activity systems.

During any early conceptual or design phase there is a focused effort on producing fit for purpose designs eliminating redundancy. As the main platform design progresses, the topsides team requires interface data on reactions, dimensions and utilities all of which start to define the size of the overall platform facility. Sometimes, because of the lack of appropriate involvement, the early rig arrangements are poorly defined and based on incorrect assumptions and the project team carries these initial assumptions forward. As the project moves to detailed design changes are identified which affect the topsides and can lead to significant weight and cost changes that have major impacts late into detailed engineering.

The same issues consistently appear across projects. Generally there is a reluctance or failure to recognize the value of placing operational drilling staff and specialist rig designers on the project teams during the early concept definition phase. This is evidenced by the disproportionate numbers of topsides engineering personnel to rig design personnel, yet the overall project cost including drilling operations may well account for 50% of the total project cost. A topsides design team can have an overriding focus on the installed weight and cost but the operational aspects of drilling are seldom understood. However, this is where the major savings can be made during the operations phase provided the correct equipment and arrangements have been specified.

Many of the above issues are regarded as "common sense", however projects often have a life of their own and tend to loose sight of common sense and best practices. The aim of this paper is to highlight what is considered to be a best practice approach when designing large integrated platform drilling facilities.

Sizing the rig using a "Wells up Approach"

Our experience has shown that the way in which the calculations are carried out to size a rig is highly variable and can be based on "Xerox" engineering or extremely limited data.

Some of the examples of errors and discrepancies we have seen are.

- The requirement to provide a string of $6^5/_8$" drillpipe in conjunction with 3 x 2,200hp, 7,500psi mud pumps. Originally, $6^5/_8$" drillpipe was introduced to allow the parasitic pressure losses to be reduced such that rigs with limited hydraulics could be used to drill deeper without adding a third mud pump. Where 7,500psi circulation systems are specified there is seldom any requirement for $6^5/_8$" and the drillstring design can be optimized.

- Errors in assumptions for required hydraulic power. Equipment vendors quote mud pumps based on input power. If it is assumed the pump is run just below full rated speed and at a pressure around 400psi below the allowable liner rating to prevent repeated failures the actual hydraulic output is significantly less. For a 2,200hp pump the realistic continuous hydraulic output is 1,670hp.

- A lack of clarity or definition of hookload versus the dynamic derrick loads.

- The inability or failure to recognize that the proposed drillstring will not withstand the collapse pressures whilst under tension and circulating out a kick.

For all projects KCA Deutag's approach is based on a "wells up approach" that can help the client optimize both the rig design and operational efficiency. Rather than accepting requested equipment ratings our approach is to step back and request the proposed well designs, numbers of wells and expected reaches. We then perform / verify the calculations in order to determine the expected operational loads.

Most projects during the early phases will have uncertainty around the numbers of wells and depths. The normal approach is to develop a series of model well designs based around increasing displacements. These model wells show the casing setting depths, planned mud systems and weights and the required tops of cement.

Each well design is modeled using commercially available software (that is used in the field and therefore we have confidence in the results) and the following loads validated.

- Torque and drag in all hole sections including casing runs, tripping in / out, with or without rotation.

- Hydraulics. During this work the drillstring selection and design is verified.

For the torque and drag sensitivities are run on the friction factors, if field data is available it is used but a range of friction factors is typically run to check sensitivities and to account for both water based and oil based muds. The highest torques will be seen during the displacement of the well to a water based completion fluid.

For hydraulic calculations sensitivities are run on the mud weights and increased rheology to allow for the effects of mud going out of specification as well as the potential requirement to increase the mud weight as the inclination increases.

The results are tabulated for each scenario to allow the worst-case scenarios to be identified.

It is also important to have an understanding of the overall distribution of well depths. The loads from the most frequently occurring wells can then be compared to the deepest wells. Although dependent upon the overall well distribution the typical approach is to size the drilling equipment such that it is operating at ca. 75% of maximum load in the most frequently drilled wells and ideally in the deepest wells it is utilized to near capacity. This represents a reasonable compromise of providing sufficient redundancy without over rating equipment.

Our experience has shown that in many cases the principal drilling equipment is sized based on the deepest planned well. Yet this may be only one well or a limited number and results in a significant over capacity and higher cost. Reviewing the well designs, determining the most onerous sections and numbers of wells to be drilled, while still ensuring the rig is capable of drilling the deepest well (albeit at slightly reduced efficiency) usually results in significant cost savings.

The mud volumes in each hole section and an operational breakdown of how volumes and the different fluids will be handled during cementing are checked in order to determine any restrictions and the ideal pit capacity. Bulk volume requirements for both cement and barites are also calculated.

The final sizing of the mud pits and silos is then based upon the supply period and any minimum stock requirements, such as the minimum cement that should remain on board after completing a casing run.

From the data the requirements for setback and the pipedeck capacity are determined. Further optimization of the pipedeck loads are also considered to cater for batch drilling.

The offset data is reviewed to determine expected penetration rates, which are required to size cuttings containment systems.

Determining high level philosophies

Before starting to specify equipment one of the first issues to resolve are the project philosophies. Companies have goals and statements typically covering their global HSE aspirations and requirements. These should be reviewed and the goals translated into practical terms / design features that specify the resulting impact on the rig design. The two most common areas where discrepancies can occur are with mechanization and the treatment of drilled cuttings.

The reasons for mechanization must be clearly understood and then a clear requirement laid down for the levels of mechanization.

The method of dealing with cuttings discharges must also be agreed upon since changing the requirements to provide a form of containment late into detailed design will have a significant impact on costs.

Mechanisation, safety and efficiency

On mobile rigs that handle large tubulars and are subject to significant heave, roll and pitch the justifications for mechanization are relatively obvious. On fixed installations the need for mechanization is perhaps less clear.

As well depths and tubular sizes increase the justification for mechanization becomes obvious due to the increased safety hazards and crew fatigue associated with manual handling. Mechanizing a rig should only be based, in order of importance, upon,

- Safety and the goal of removing personnel from the drillfloor and hazardous areas.
- Ensuring operational consistency when handling any tubulars by providing systems that remove some of the reliance on the Drillers ability to perform repetitive tasks continuously.
- Removing the need for personnel to handle heavy tubulars.
- Improving drilling efficiency.

Comparing safety statistics between mechanized and non-mechanized rigs requires careful analysis of the root causes of the incident. Statistics generally show that a significant proportion of accidents occur on the drillfloor or during tripping operations indicating the benefit of installing pipehandling equipment. In some cases the statistics between manual and mechanized rigs show no appreciable improvement or in some instances a higher number of incidents that are generally caused by dropped objects aggravated by the extra equipment installed in the derrick. In one case during 1994 the NPD reported some installations having in excess of 50 dropped objects within a year (1). However rather than attributing the problems to the equipment many of these problems can be traced back to,

- The installation and retrofit of mechanized equipment on rigs that were previously designed as manual rigs. This usually results in a number of compromises that may reduce some hazards but also introduces new ones with the addition of extra equipment within a derrick or mast.
- An ill advised contracting strategy for the project whereby a number of diverse vendor equipment packages are combined with hoisting and pipehandling systems.
- The failure to recognize the importance of integrating and controlling the different systems or to consider all the potential operations that must be carried out.

Once the decision has been made to mechanize a rig the levels of mechanization should be agreed to, along with the way in which the equipment is packaged and supported in the field. The end user, the Drilling Contractor, should carry this out in conjunction with the equipment vendor, as they will have to operate and maintain the equipment. This approach also allows the contractor to take ownership for the performance of the rig.

Comparing the performance between similar rated mechanized and manual rigs could show that a manual rig with an experienced crew may be almost as fast tripping as the mechanized unit. Nonetheless, the mechanized unit provides consistent performance and reduces safety hazards.

A correctly set up mechanized rig will operate at higher tripping speeds than a manual rig as well as reducing personnel exposure. Mechanization has at times been justified on the basis of reducing the crew numbers. Our experience has shown that there are no appreciable difference in crew levels between manual and mechanized rigs. Even with the latest mechanized equipment there are numerous drilling operations where the full complement of a regular drilling crew are required. On a mechanized rig the number of maintenance personnel is often increased. In addition, these personnel also require increased specialized skills, and as a result are more expensive. The same conclusion was inferred by Croucher (2).

Determining mechanization levels

Compared to mobile units, fixed platform or dry tree installations can have significant weight, space and center of gravity concerns.

During the design phase there is a focused effort on controlling weight. Inevitably the rig dry and operational loads are queried and the rig weights are highlighted as an area where weight can be saved. One of the areas is through the slimming down of the rig design and the removal of rig equipment – particularly if the design team cannot accurately identify the operational benefits of installing the equipment or have a clear philosophy in place as to why the rig is being mechanized. Questioning the need for mechanization at this point, can lead to the partial removal of equipment with the risk of reducing the overall functionality of the rig as the vendor systems are designed to work with and complement each other.

The most effective approach is to document the implications of any corporate policies on the rig equipment, weight, cost and operability in a technical note as part of the initial project philosophies. These issues should then be discussed, agreed and formalized such that they can be incorporated into the rig design. If this is not done the issues can remain open and the project team may design the facilities based on their interpretations only to find later that the operational personnel hold different views.

Nearly all of the recent newbuild mobile drilling units have incorporated mechanized equipment. The level of mechanization has included dual activity systems that have allowed casing to be built and racked offline in order to reduce the flat time. Typically these have been specified on the floating units that characteristically have capacity for very large derricks and corresponding drillfloors with no restrictions of decks below. Because of the potential savings in flat time, similar arrangements have been theorized for platform rigs - unfortunately without consideration for their size or weight impact or operational efficiency gains over the expected life of the primary drilling campaign.

Seldom are any comparisons or estimates made of drilling performance between the field appraisal wells and that expected with a purpose-designed rig. The initial wells may have used a less than optimum well design or drillstring and been drilled by a rig with limited hydraulics and power. Generally any proposed new build rig will provide more hydraulics and power and it would be reasonable to assume that improved drilling rates will be achieved. Ideally the correct approach must be to review the overall well times based on a technical limit type approach against the proposed rig specifications. In most cases the drilling performance can be improved significantly without having to install overly complex dual activity systems that can compromise rig size and weight objectives. Also when the operational efficiency gains are considered over the primary drilling campaign the gains are negligible. Past the initial drilling programme, such systems have little use as the majority of work can comprise of sidetracks and workovers where there is a limited need for such systems.

The overall derrick size will dictate the pipehandling systems that can be installed. Within the typical platform derrick sizes (40’ x 40’) the ability to be able to safely and efficiently carry out two totally different activities such as drilling ahead and racking back casing is questionable, especially during periods of rapid drilling. Similar concerns were also documented by Simpson [3]. These limitations have lead to the development of alternative arrangements (Figure 1) for reducing flat time by building casing stands outside the derrick area.

When the step-by-step operations to carry out a dual activity operation such as drilling ahead while building and racking casing stands are analyzed it becomes obvious that there are a number of areas of concern.

- There may be a requirement to have a casing crew onboard requiring additional personnel. A problem compounded by the bed space restrictions on a platform.
- Either a second iron roughneck or casing tong is required on the drillfloor.
- There are operational safety concerns over having sufficient space between the different operations within a relatively small drillfloor area.
- The speed of drilling may frequently interrupt the other activity.

When these issues are considered as well as the increased setback load, additional equipment cost and complexity the economics of providing for casing racking whilst drilling the section over a typical platform well campaign is usually uneconomic.

Selecting equipment ratings and vendors

After sizing the primary drilling equipment, the contractual approach to purchasing, installing, commissioning and support in the field of the mechanized equipment requires careful consideration.

The increasing levels of mechanization on a rig have been detailed by Simpson[3] and Reid[4]. The steps between a rig having a minimum mechanization level of an Iron Roughneck and topdrive to a rig with full pipehandling requires a significant investment. Drilling operations cannot be compared to other repetitive industrial processes. The different drilling equipment systems have to work in unison throughout their operating range and interface with a number of other pieces of equipment to provide a single machine. The situation is further complicated by the wide variety of drilling operations, equipment and range of sizes that have to be handled. For example the piperacker has a multitude of variables from the arm position to load sensors to confirm the stand or tubular can be lifted. At the same time the piperacker must interface with the drawworks, blocks, iron roughneck, power slips, mousehole or pipe conveyor. This indicates that there are significant numbers and possible permutations of how the equipment will be used during operations. The way in which all the interfaces and interlocks are designed and arranged to work to prevent operator errors between each piece of equipment is a challenge.

In some cases there has been a tendency for operators to "cherry pick" equipment from vendors based on previous rig experience rather than allowing the Drilling Contractor the freedom to specify equipment. This can lead to a number of different vendors' equipment being specified on the drillfloor. In some cases, the importance of properly integrating these various pieces of equipment is underestimated or is an afterthought. The result is that the assignment of responsibility and accountability for integrating all the systems may be lost, leading to problems during the commissioning and acceptance phase. The problems may subsequently be carried over into the operations phase. The problem is exacerbated further when a shipyard or fabricator, that has little or no appreciation of the equipment functions, assembles the rig with limited involvement, input or control by the Drilling Contractor.

The packaging of the equipment with a single or limited number of vendors also simplifies the in field support, especially since the major drilling equipment vendors can now provide technical / diagnostic support and assistance to the rig maintenance personnel via modem links.

With any new build the integration and commissioning of the drilling equipment is a critical period and is historically an area where problems surface. With a mechanized rig the drillfloor systems must be integrated and tested such that they work as one. Contracting multiple vendors does not aid this process and requires careful consideration as to how responsibilities and accountability are assigned, and generally is not a recommended course. The recent mergers and acquisitions have resulted in a number of major drilling equipment vendors that are capable of providing a complete drilling equipment set. In order to minimize interfaces with the mechanized pipehandling systems a single equipment package vendor is preferred.

Under a traditional design scenario the engineering contractor draws up detailed specifications for every item of equipment. This is an expensive practice and tends to lead to every item becoming a custom version.

A more effective approach is to identify the rating required and to then allow the Drilling Contractor and their selected equipment vendors to work as a team to produce a detailed equipment and rig specification. Following this approach allows the Drilling Contractor and equipment supplier to take ownership for the performance of the rig.

Reliability and maintenance

One area that is seldom defined in the initial design stage is the issue of equipment failure on mechanized rigs. In a number of cases the client makes the statement that the rig is to be mechanized but in the event of equipment failure operations are to continue in a manual mode. However when the steps to achieve this are considered, i.e. the need to ask the drillfloor personnel to quickly revert to manual operations, which they may not have worked for a considerable period of time, there is the increased risk of an incident. The philosophies of how to continue operations in the event of equipment failure should be agreed as part of the overall mechanization philosophy. Specific operator requirements can lead to custom equipment versions rather than the vendor standard. Clearly not every equipment failure will shut the rig down, operations may only be slowed. The best approach is to ensure the equipment is rigorously maintained to avoid failure during critical periods and provide redundant systems where possible.

Frequently platform operations contracts do not allow for sufficient time for the contractor to carry out adequate maintenance of equipment in order to minimize downtime. Scheduled maintenance can be forced into an opportunity basis regime. Compared to mobile units where rig moves may allow for several days of maintenance and unrestricted access for vendors a platform rig is theoretically available for operations all the time. In order to ensure equipment reliability, points at which the rig can be shut down and access given to maintenance personnel, should be allowed for in the drilling programme. Typically maintenance requirements equate to about 1 hour for each day of operations or about 2 weeks / year.

Fabricator Involvement

Fabricators have different ways of building facilities. Early involvement of the rig fabricator is required and ideally the fabricator should be on board at the start of detailed design. The detail design phase can then concentrate on meeting the design needs of only one fabricator, which may be enhanced by the fabricators experience – and result in a more cost efficient design that is easier to build. The fabricator's early input is also valuable as drawings can be tailored to suit the fabricators requirements eliminating or reducing the need for redrafting work. Another benefit of early fabricator involvement is to ensure that the fabricator understands the operational needs, for example the design of mud pits. Operationally it is preferred to provide tanks with bottom suctions to avoid dead volumes and internal stiffening which creates dead areas. While the overall arrangement may be more expensive to fabricate, the operational advantages more than justify the cost.

Operations input

It is generally accepted that without the early involvement of the end user it is unlikely that the design will meet all the users needs. In the past, design groups have tended to be insular, design orientated and with limited practical drilling rig experience. Many of the same mistakes are repeated from project to project. Engineering project teams typically consist of a number of engineering staff that will have transferred from a recent project. Their level of involvement through commissioning and beyond is limited and seldom will they have received direct feedback from the operations personnel on the efficiency of their rig design. As a result designs are only as innovative as the last job.

Having an operations person (a Rig Toolpusher or Rig Manager with recent rig experience relevant to the planned operations) within the engineering team has a direct benefit. However, because the operations personnel do not provide direct engineering skills compared to the rest of the project engineering team they are often considered to provide little added value. This is especially true with a conceptual or detailed engineering team where operational input can be viewed as the source from which all changes originate and results in nothing but problems for the engineering team.

The most effective approach is to assign the Rig Manager, supported by a Drilling Engineer at the start of the project. Both these individuals see the project through from design to operations. This provides greater ownership of the design and ensures that early identification and training of rig crews takes place well in advance of operations starting.

The operational position requires an aggressive approach. There can be a tendency to focus on specifying / picking equipment and reviewing drawings, all of which are necessary, but the high value lies in understanding how the wells will be drilled and the rig equipment will actually be used for each operation.

To achieve this it is necessary to break down all the operations that will be carried out and identify all the equipment required. This is best achieved by following a structured approach. The well designs are taken and the well is “drilled on paper” following a Technical Limits Approach. This approach is being used with great success by our operational rig teams to:

- Identify all the risks associated with a well design and operational steps.
- Define the ideal well times based on historical and offset well data.
- Identify the areas where performance improvements can be made and put in place a plan to realise the gains with the aim of reaching the ideal or technical limit well time.
- Improve performance by capturing and analyzing detailed operational data.

The same approach can be used during the rig design process and should be conducted as soon as an initial rig layout and preliminary well design is available.

Each hole section is broken down into the different steps that are required to complete all operations. However at this early stage rather than assigning times for the operations, the following steps are identified - an example is shown in Figure 2.

- The operations that will be carried out.
- The equipment that will be used - both the fixed rig and mobile equipment and any third party contractor equipment.
- How each item of equipment will be handled using the installed equipment, components and systems.

This approach immediately starts to identify how all the drilling tools and equipment will be handled and any special requirements.

In many cases the approach during the early project phases is too superficial resulting in a lack of understanding of equipment limitations and the omission of equipment that is required to provide a complete working rig. In some cases one contractor may provide specific equipment only to find that the operator will also make arrangements with another contractor to supply some of the same equipment. The technical limit approach can provide a process to focus the overall team operationally identifying all the required interfaces ad equipment in order to avoid duplication.

The early involvement of the operations team with the design team also demonstrates the importance of identifying all the other contractors to ensure their equipment is compatible with the other design considerations of the rig. This is particularly important on dry tree installations where a large proportion of concurrent well intervention work is carried out alongside the main rig. Duplication is avoided and a well-defined process ensures that the rig design team has visibility of how all the equipment vendors will be integrated into the overall design.

As the sequence of operations are built up the technical limit tool becomes a powerful means of completing a thorough detailed analysis of all the planned well activities and operations that influence the rig design and equipment selection past the traditional approach of mud pump ratings, hookload, torque and mud pit capacity.

Conclusions

The issues discussed may be regarded as "common sense" yet many projects continue to suffer as a result of decisions made (or, in some cases, not made) during the early phases of conceptual engineering definition. These studies, many of which continue to be carried out by large integrated engineering contractors, must be bolstered by inclusion of team members with considerable operational drilling and practical rig design experience but typically the level of practical drilling involvement is at the discretion of the operator.

The value of this early input is well recognized in that the cost savings potential on a project are the highest during the conceptual phase and the lowest later on during the installation and operations phase. Problems identified in conceptual engineering can be rectified much easier and cheaper than if the problem is found much later.

The following conclusions can be drawn.

- The rig design must be based on a rigorous "wells up approach".

- During the conceptual stages the philosophies and expectations must be translated into practical requirements against which the design team can work.

- Operational input has a high value. However operational input does not extend to an operational person simply answering questions from the project engineering team. It requires a proactive and aggressive approach that verifies the well designs, installation loads and operational requirements in order to specify the principle drilling equipment.

- Each step of a proposed well programme must be examined to identify where the rig systems can be optimized. The use of a technical limit process to test the rig design against the proposed well design identifying opportunities for optimization is a significant benefit. The approach gives the rig design team a much better understanding of their design's impact on operations.

- The analysis also has significant potential to impact the rig operability and HSE results. The approach also ensures the early buy in of operational and contractor teams.

Acknowledgments

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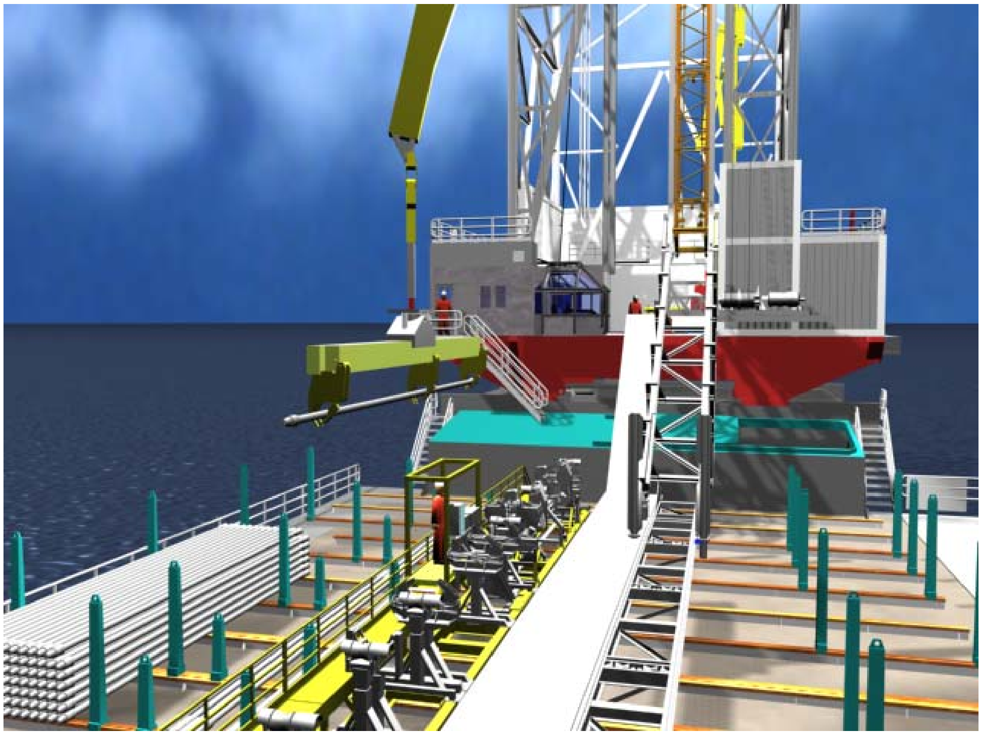
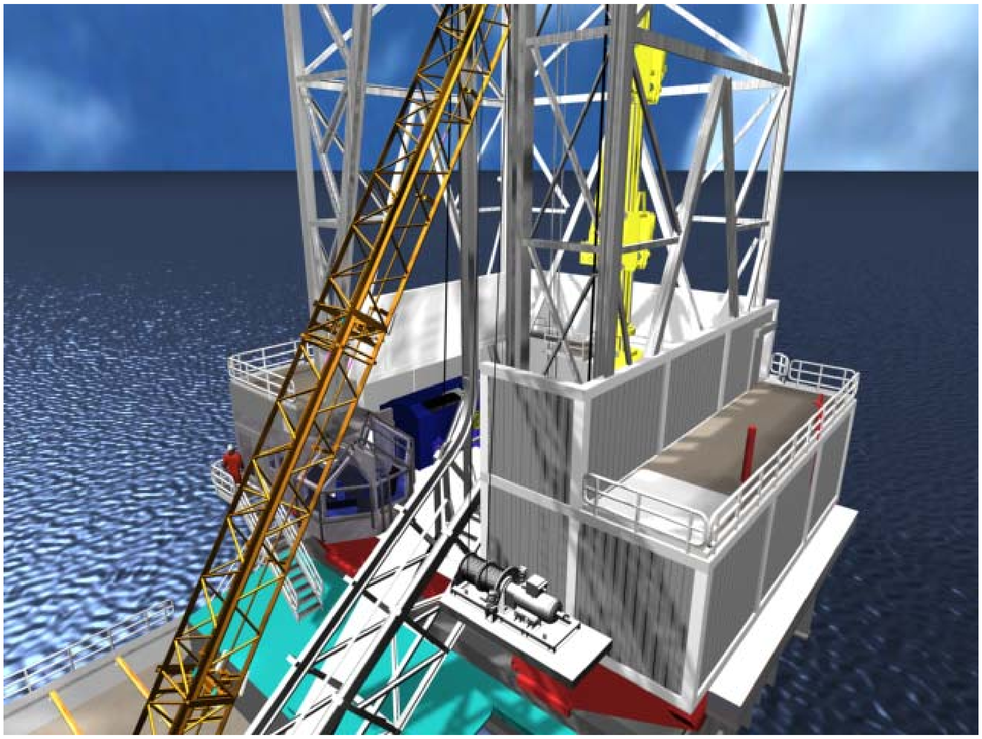
Figure 1 – pictures A, B, C and D

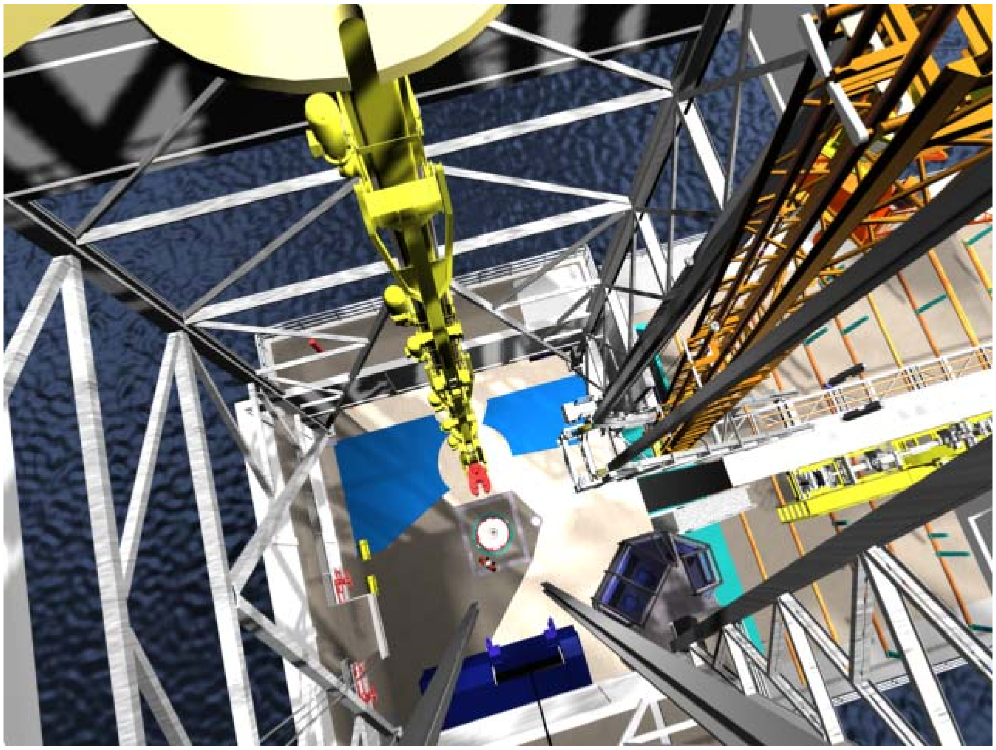
A. Building 90ft stands outside the derrick on the pipe deck.



B. Transferring the stands from horizontal to vertical.



C. Transport frame brings stands to the vertical.



D. Collecting the stands for running into the well.

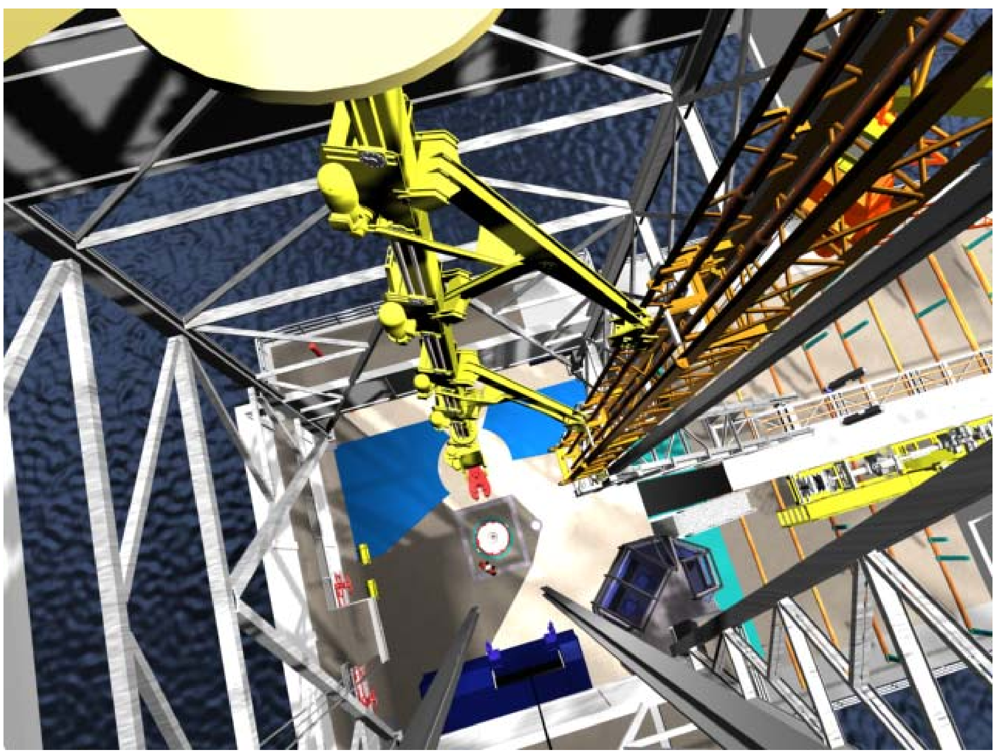


Figure 2 – Example of Breaking down Operations to Identify Equipment Requirements

Step	Activity	Handling Method	Assumptions / Discussion
1	Picking up casing joints.	The individual joints are collected with the PDM from the storage bays and placed on the conveyor. The conveyor feeds in towards the well center.	The connections will have been cleaned, inspected and greased on the pipe deck beforehand. 20ft bails are required to accommodate fill up tool and cement head.
2	Feeding casing into the drill floor.	The conveyor belt feeds the joint into the well center.	
3	Lifting casing from horizontal to vertical	The V door machine extends down and clamps the joint on the conveyor. The V door machine hoists the joint at the same time the conveyor tails the pin end.	
4	Tailing in the casing joint	The conveyor tailing rollers hold the casing joint from swinging as the V door machine brings the joint to the vertical position.	
5	Moving to well center	The V door machine extends to the well center holding the casing joint vertically.	
6	Stabbing conductor	The threads are inspected and doped as required. V door machine lowers the joint and stabs the connection.	Quick release inflatable style pin end protectors are supplied with the casing package. Casing contractor's power pack is likely to be diesel powered. Need to provide a suitable laydown area near to the drill floor for this unit. Also consider electrically powered unit, need a suitable breaker / tie in point.
7	Lowering blocks	The blocks are lowered and the spider elevators dropped over the box end.	It is assumed a suitable casing fill up tool is installed onto the topdrive prior to the start of the casing run such as.
8	Release of V door machine	The V door machine releases the casing joint and returns to the V door area to collect the next joint.	
9	Removal of stab in guide	The stab in guide is removed.	
10	Casing tong is latched around the connection	The casing tong is brought to the well center and latched around the casing connection.	Current assumption is that the casing tong is supported off a dedicated suspension arm capable of powered rotation and powered in and out of the well center. Casing tong is supplied by the casing contractor.
11	Torquing of connection	Casing tong torques up the connection.	Depending upon string being run joint analysis may be required, assumed to be supplied by the casing contractor.