WP2

Eavor-Loop efficiency study for customized rigs InnoRig XLD90 Study

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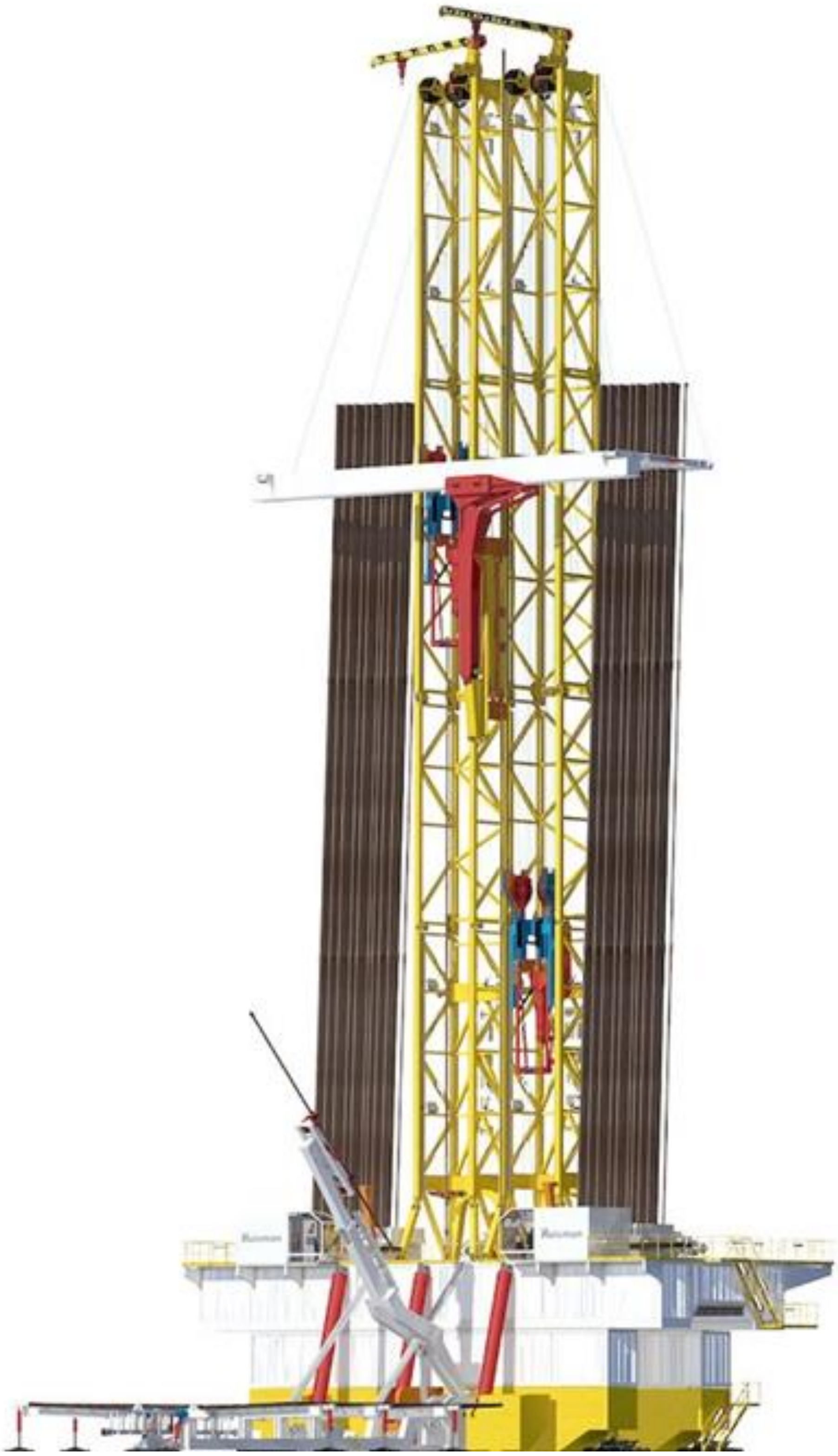

Executive summary

The work conducted as part of WP2 has the aim to design a dedicated and more automated Eavor-Loop rig for cost effective drilling and completion such that the drilling can be carried out on a 24/7 basis in the urban environment. In order to achieve this, various parameters that affect the efficiency of drilling such wells, have been analysed to improve the most costly activity of delivering the geothermal well; the drilling activities.

The drilling speed is influenced by factors such as drill bit design, mud system, available power, and the control precision of the rig. An automated rig can save time by automating the pipe handling process and reducing manual handling of bottom hole assembly components. Additionally, the automated rig can provide accurate control of drilling parameters, reducing the number of times the drill string needs to be pulled out to replace the drill bit. Therefore, the use of a dual derrick rig as a cost and time-saving method for drilling the Eavor-Loop well system has been compared to the use of two conventional drilling rigs and with one dual derrick system.

The dual derrick system has the ability to drill two wells simultaneously with only one floor crew, resulting in a smaller crew size and cost savings of around 16%. Combining two rigs into one system also results in a much smaller size of the required drilling site. The required space to accommodate a dual derrick compared to two conventional rigs is approximately 40% less. This small footprint can play a vital role in the aim to position large geothermal plants closer to dense urban areas.

An alternative scenario is also presented where there is not enough space for two conventional rigs or a shortage of skilled personnel. In this case, the single conventional rig would be less efficient due to a lack of automation, resulting in additional time per well, a larger crew and half the capacity of the dual derrick system. The dual derrick system can complete a project in 170 days compared to 300 days for the conventional rig, resulting in a cost savings of 19% and a time savings of 43%.

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1. Introduction

1.1. Geothermal energy

Currently the main source for local generated renewable energy in the Netherland is offshore wind energy. This source of energy has been developed with great pace. Downside of the technology that it only provides power when there is wind.

To be able to provide a more consistent renewable energy supply and shave off the peaks, geothermal energy can become a larger player in the energy mix in the near future. The majority of geothermal wells that are drilled are shallow wells (~ 500 mtr) are actually temporarily storage systems to collect energy in summer periods and extract heat in colder periods. To be able to make a larger contribution to the overall energy supply, geothermal wells with high power output will be required at competitive costs levels with other renewables.

To be able to introduce deep geothermal high temperature wells in the Netherlands, Eavor is investigating the implementation of an Eavor-Loop system. This type of geothermal well has been developed recent years.

With most geothermal well designs, water is pumped at depth trough permeable rock layers, absorbing the heat, and then brought back to surface. The hot temperature water runs through a heat exchanger with a local heat network, after which it is pumped back to repeat the cycle. These systems work quite well at the start of a project, but as the fluid flows through the rock layers, it also dissolves salts and other elements, resulting in corrosion, local clogging and other side effects which potentially reduces the efficiency of the system over the lifetime.

The Eavor-Loop is a closed loop geothermal system, where the fluid flows from surface, through long deviated drilled wells and back to surface. As the fluids flow not through permeable layers, but through pre-determined drilled holes (loops) corrosion and clogging is not a large issue anymore, potentially greatly improving the efficiency of the overall system. To gain maximum efficiency for the geothermal system, high temperatures and large energy output are of the essence.

To meet these criteria, the well design can be summarized by:

- A lot of deep wells are combined to be able to extract a lot of heat from one system
    - This results on an average of 24 horizontal or deviated wells with a length of ~ 3000 meter each.
- Large diameter wells to create a maximum of heat exchanging surface between the well and the rock formation.

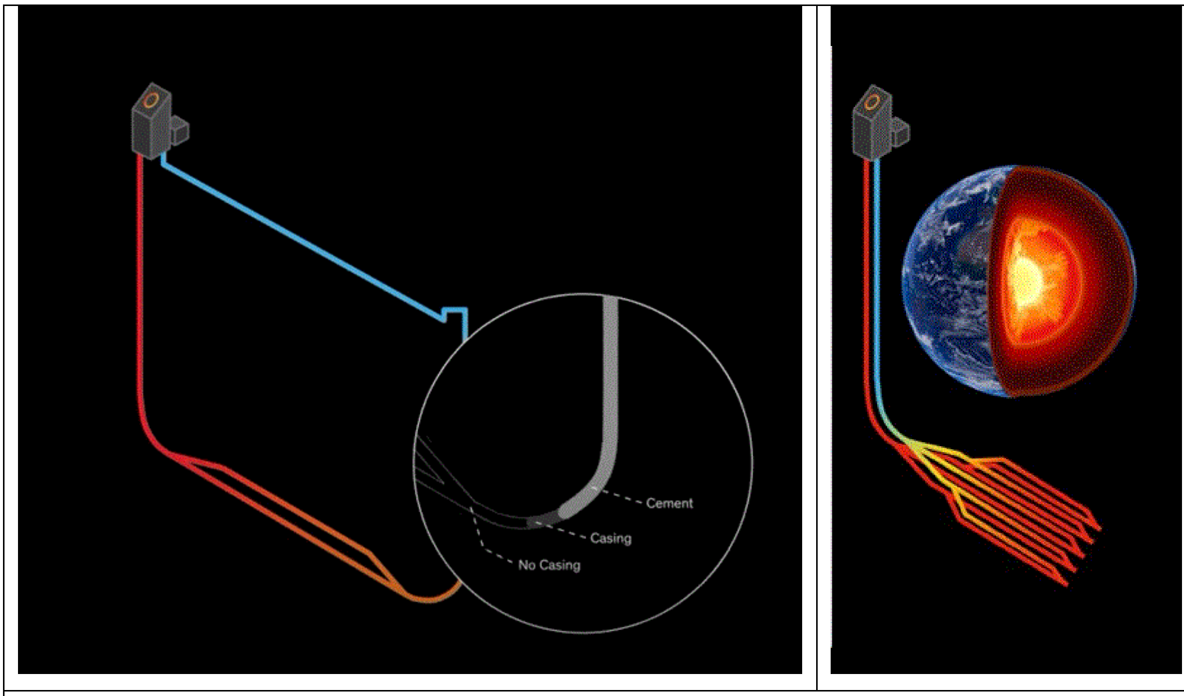

Figure 1: Geothermal closed loop system. Source: Eavor

The above sketched scenario needs approx. 57,000 meter to be drilled.

To be able to deliver the heat close to the end-users, it is expected that these drilling operations will need to be performed usually relatively close to a city or industrial area. Therefore, space to accommodate the system and drilling activities is limited.

1.2. Goals and objectives

This study has the aim to design a dedicated Eavor-Loop rig for cost effective drilling and completion such that the drilling can be carried out on a 24/7 basis in the urban environment.

The study investigates the impact of such a custom geothermal well delivery drilling system to minimize the time and cost per delivered loop system and at the same time work at a reduced footprint.

With such system geothermal energy can be supported to grow toward a larger contribution to renewable energy supply in Europe and abroad.

2. Geothermal wells efficiency parameters

The deep high temperature geothermal wells that are required for the loop system have been analyzed on their time and cost driving parameters.

The well program consists of:

Amount	type	type	Vertical depth [m]	Length [m]	Notes
1x	Inlet well	Vertical, cased 13 3/8 ”	3275		Dressed with 1x 9 5/8” production casing that connects to 12 legs
1x	Outlet well	Vertical, cased 13 3/8 ”	3275		Dressed with 1x 9 5/8” production casing that connects to 12 legs
24x	Legs	Horizontal, open 7”		2100	2 legs are connected as 1 loop. 24 legs = 12 loops

Note: 1” means 1 inch = 25.4 mm

2.1. Drilling speed (ROP)

For as well as the vertical section as for the deviated wells, the key parameter in the time per well is the drilling speed, rate of penetration. This speed in meters drilled per hour is determined by a lot of parameters as drillbit design, mud system, available power and the control precision a rig can offer to power the bit. But also the speed of adding drillpipe during drilling has impact on the overall drilled meters per hour.

2.1.1. Connections

With a custom rig this pipe handling process can be automated and optimized, therewith reducing the “waiting time” for adding pipe, starting pumps and lower the 1 meter to start drilling.

With this automated system on average 2 minutes per connection can be saved. For comparison with conventional operation only 1 minute saving per added pipe has been implemented in this study.

2.1.2. BHA handling

Handling the bottom hole assembly usually requires to a crew and rig to be able to handle a lot of different items with different diameters, connections, lengths and weights. Therefore, this can take a lot of time and requires usually a large crew to be available on the rig floor. With an automated rig, it is always an evaluation for what part of the BHA remote /automated handling is off value and what part is more efficient to run (semi) manually. The proposed custom rig design includes equipment that can handle various sizes, lengths and heavy weights directly from the vertical setback (pipe storage), therefore reducing the amount of manual handling actions and increasing the speed of handling. This is mainly seen in running heavy weight drill pipes and drill collars. The remote handling of these items increases the safety of the operations significantly and allows to work with only a small rig crew. Although several hours per lateral will most likely be saved, it is not possible to mathematically place this in a model, therefore this efficiency gain in this study has been limited to 0,5 hours advantage per full pipe trip.

2.1.3. Drilling parameter control

Also, compared to a conventional rig, the automated rig can provide a very accurate control on the combination of the weight on bit, top drive rpm and torque and pump parameters, therewith providing an optimum balance between drilling speed and drill bit wear. Parameters can be optimized by using the data of the other drilled (similar) wells and in real time of the leg that is drilled at the same time.

Having good control on the wear of the drillbit minimizes the number of times one needs to pull out the entire drillstring (in this case over 5 kilometer) to replace the drillbit, after which it needs to be tripped back in the hole.

This automated system has a high potential to reduce the time per well. But the exact impact cannot be accurately estimated upfront as the final drilling speed is depending on the mix of the above parameters and the formations that one encounters. Therefore, this advantage has not been used in the comparison study.

2.1.4. Drilling steering control

Steering the drill bit in the right direction, steerable drilling, usually is controlled by a dedicated steerable driller, often offered by a more expensive and less efficient 3rd party service, so not as part of the contractor rig crew. With the intended automated drilling system, the steering process is fully automated. This “auto pilot” system ensures the hole is drilled at the correct direction and depth, maximizing the heat exchange efficiency of the well.

2.1.5. Automated drilling sequences

By combining the above functions of automated connections, automated drilling parameter control and automated steering control, the rig will have the ability to drill large, deviated parts of the well autonomously. As a result, the rig crew can be kept small and the rig floor will be only used by the crew during BHA operations, minimizing exposure thus safe by design. The effect of a small rig crew has been incorporated in the comparison study.

Figure 2: Integrated Huisman drilling parameter control

Figure 3: Cyberloop remote directional drilling

2.2. Tripping speed

During the process of drilling a deep deviated well (a leg) quite some time can be lost for tripping in and out of the hole. This is required to retrieve the drillpipe and BHA after completing drilling or in case a drill bit is worn out and needs to be replaced. With the Eavor-Loop design multiple legs are drilled starting in a vertical well at 3275 meter depth. This means that prior drilling one needs to trip in 3275 meter drillpipe. Also, in order to be able to kick out sideways to start the deviated hole, it is also required to trip in a whipstock, run on 3275 meter pipe, after which the pipe needs to be tripped out again. Summarized this is 13100 meter pipe tripped in and out prior starting drilling. Once drilling, the drillbit can be used until it reaches the end of its running life. For the comparison it is assumed that the "conventional" rig to which the Huisman custom rig will be compared, also is equipped with a high-end accurate weight on bit and torque control system, in order to maximize the lifetime of the bit. This is actually still not the case for a lot of rigs in the field.

Based on the input received from Eavor, the bit will have an expected bit life of 1050 meter, exactly half the length of the total drilled leg of 2100 meter. As a result, one extra bit trip is required. A total of 17,300 meter (~57,000 ft) of pipe will be required to be tripped in and out of the hole. Fast tripping speeds do help here to increase the efficiency of the operations.

Table 1: lengths of ripped pipe during drilling of 1 leg

	Distance [mtr]	**Distance [ft]**
Run in cased hole	3,275	10,745
Leg in (drill 1050 mtr)	drilling	drilling
leg out	1,050	3,445
Run out cased hole	3,275	10,745
Run in cased hole	3,275	10,745
Leg in	1,050	3,445
Drill further (1050)	drilling	drilling
Trip out leg	2,100	6,890
Trip out cased hole	3,275	10,745
	17,300	**56,758**
pipe stands (90 ft)	631	631

With a conventional rig, the tripping speed is highly dependent on the rig crew on the floor and on the monkey board. Usually, maximum tripping speeds can be quite reasonable, but only with the best crew and for a short period. As these speeds are not consistent, the average tripping speed usually stops at 610 mtr/hr (2000 ft/hr). On a conventional rig this requires approx. 4 persons on the floor + 1 on the monkey board at height +1 driller + 1 assistant driller = 7 people. Additional crew is required to control the mud system and to do maintenance.


Figure 4: Conventional pipe tripping with manual tongs and slips. Requires 4 people on the floor + 1 on the monkey board

Source: https://www.youtube.com/watch?v=Hlv3xiUUADA

	
Figure 5: Conventional pipe tripping: 1 person at 25 meter height handler pipe from the setback towards well centre *https://www.youtube.com/watch?v=kOvLDfJ_lv4*	*Figure 6: (Monkey board seen from floor)* *https://www.youtube.com/watch?v=-j-r1FjUAj4*

The above process has been optimized and fully automated on the proposed InnoRig XL90D.

Pipe tripping is now a fully automated sequenced process, while the driller watches the operation from within the drillers cabin.

The system automatically loads 3 pipes combined (90 ft stand) from the vertical setback towards well centre, where it is picked up by the top drive. Traditionally one has to wait until the hoist block is fully at high position prior being able to add a pipe to well centre. This requires valuable waiting time. To gain even more speed, the two important operations are performed simultaneous on the InnoRig. As soon as a pipe stand is tripped into the well and it is hanged off in the slips, the top drive is retracted to the rear, out of well centre. Now the well centre is already cleared, and a new stand can be added and connected to the lower connection. In the meantime the (empty) topdrive is hoisted to high position and extended back to well centre. Here it takes over the pipe stand from the automated pipe racker, after which it is immediately ready to lower the new stand into the well.

The optimized hand-overs between machinery and eliminating the waiting time on the topdrive, result in extreme **high tripping speeds of > 1200 mtr/hr (>4000 ft/hr)**, while the actual lowering speed stays comparable to conventional rigs. <u>The study shows that the above efficiency results in a time saving of approximately 14 hours per leg.</u>

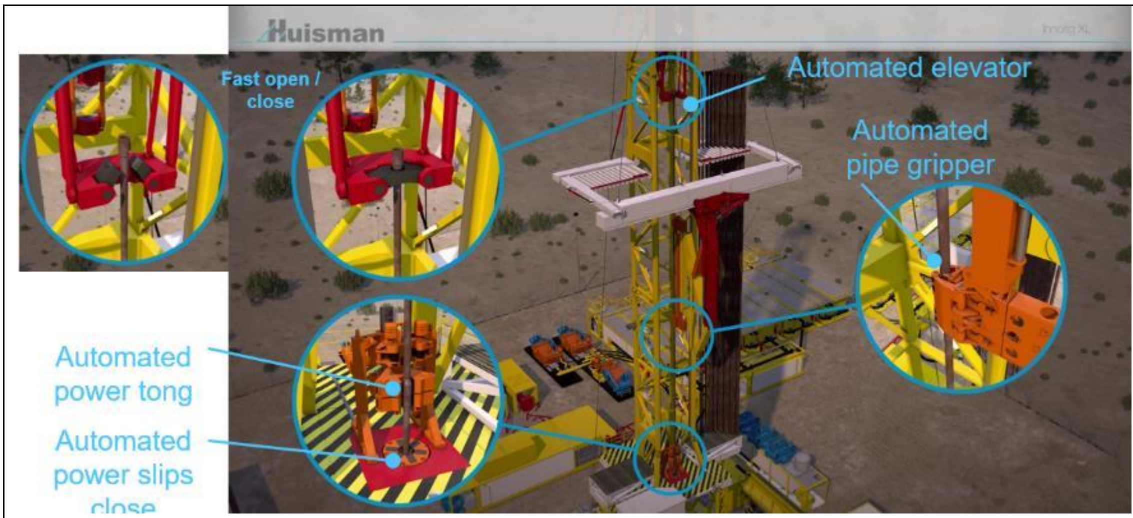

Figure 7: InnoRig XL90D high speed tripping

2.3. Completion (and casing) running speed

Also casing running is fully automated on the rig. Casing and tubing can be run in an automated sequence. To be able to run these tubulars, a casing running tool is connected to the topdrive. This tool can be best described as a grabbing device that can clamp in or on the upper part of the casing to be able to lift and rotate the casing /tubing. Only in the vertical well sections (2 psc) a completion tubing is run. Here the automated running speed can achieve 30 spc/hr vs 10 psc/hr on conventional rigs. This running speed has been tested in 2021 on another build automated Huisman rig, the HM100l. It can be run with the rig crew and does not require a more expensive and less efficient 3rd party company to do the job. The study shows a time saving of 18 hours reduction per single well, so 36 hours per 2 vertical wells saved, which are required for the loop system.

2.4. Two rigs combined: Dual derrick

To minimize the rig crew and footprint size a design has been prepared which combines the functionality of two rigs into one unit. One automated pipe racker allows to pick up pipe from the large setback, which is situated on each side of the two masts and in between the mast.

Herewith one pipe racking system supplies pipe, heavy weight drillpipe or collars to the two well centers, saving out equipment and space. The automated process makes sure there is no need for an assistant driller to operate the unit. One assistant driller can be shared between 2 cabins to operate the rig during brakes of one of the drillers.

The large drillfloor is equipped with two drillers cabins. Each well centre will be monitored by a dedicated driller, who oversees the operation.

BHA handling requires some manual support on the drillfloor. But with the new layout, only one floor crew (two people on the floor) is required to assist on the two well centres combined, and only during BHA handling. When no BHA is handled, the same crew can do other tasks as maintenance. This feature has quite an impact on the ability to minimize the amount of people on the floor and therewith crew size.

By planning the wells with a slight shift in the program, one will be able to eliminate potential waiting time between wells.

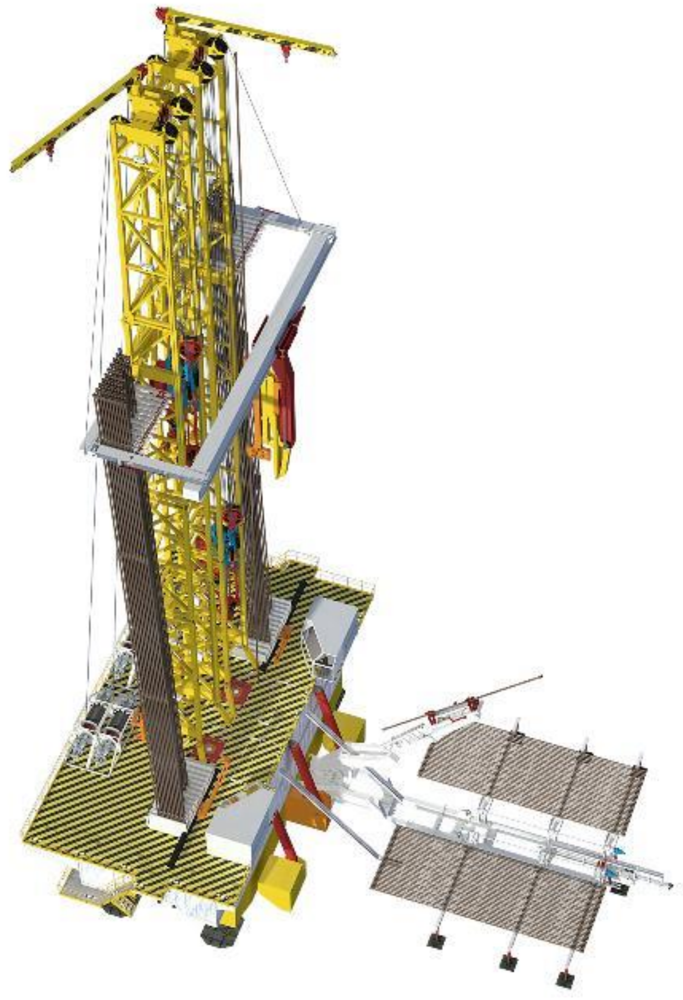

Figure 8: InnoRig XL90D dual derrick: two rigs with one combined floor and pipe handling system

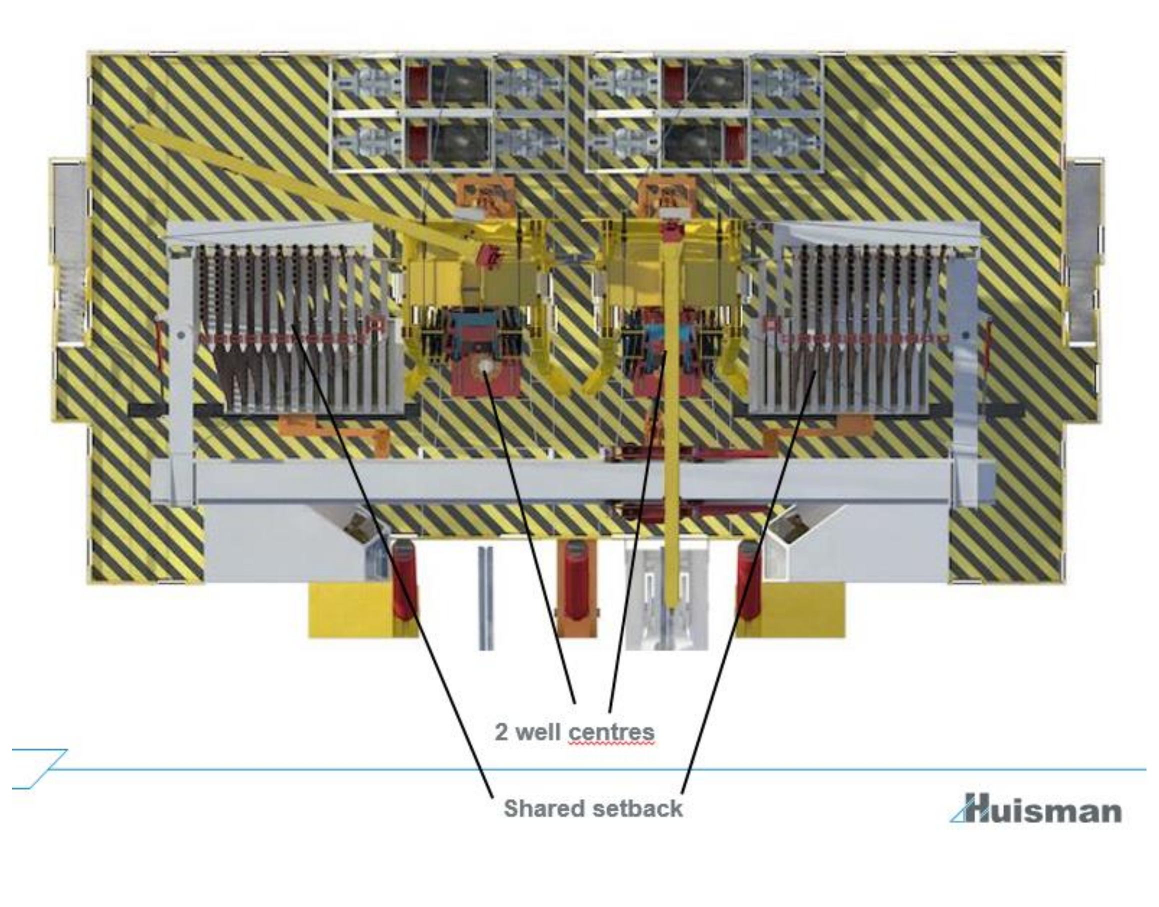

Figure 9: Floor layout with two well centres

2.5. Dual derrick: Crew size impact

Due to sharing one floor team between two well centers the rig crew size and costs are significantly reduced. This is the main reason behind the expected cost savings of the proposed unit.

During automated processes for tripping and drilling, no people are required on the rig floor. The rig works on automated sequences while the driller oversees the operation from the cabin.

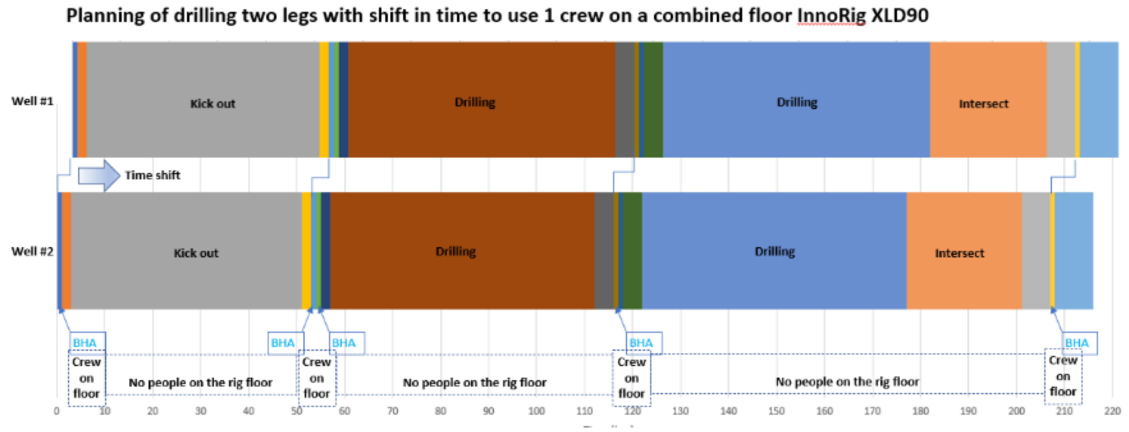

Figure 10: 1 crew to operate two well centres enabled by automation and planning

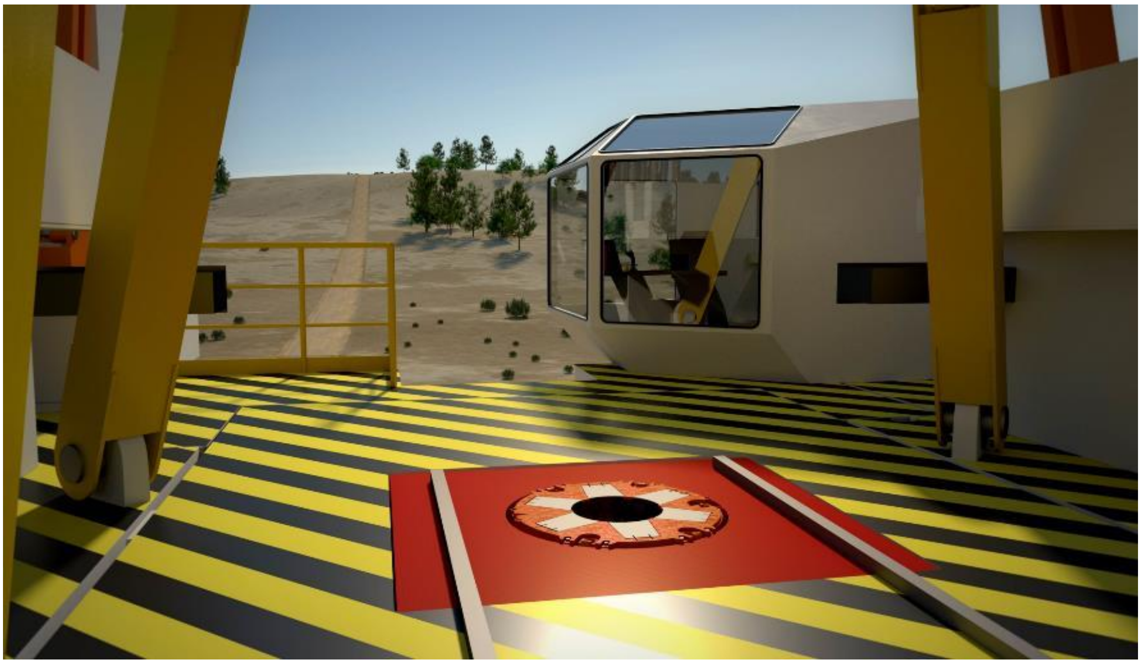

Figure 11: View on the automated drill floor InnoRig XL90 D

2.6. Footprint

To be able to support the drilling operations of two wells simultaneously, also a large mud and pumps system is required. With the dual derrick the mud system layout can be very compact, as the system allows to select different tanks and pumps to address to the required well. Although some tanks stay dedicated for each well (as kill mud and reserve mud to be able to refill the well if required), other tanks can be combined, which increases efficiency of the system and potentially reduces the cost on mud. Below study shows that the Dual derrick with custom integrated dual mud system, takes about 40-50% less space than two separate rigs. The two separate rigs could be placed closer if one would eliminate one side of each catwalk. But this would reduce accessibility to both systems.

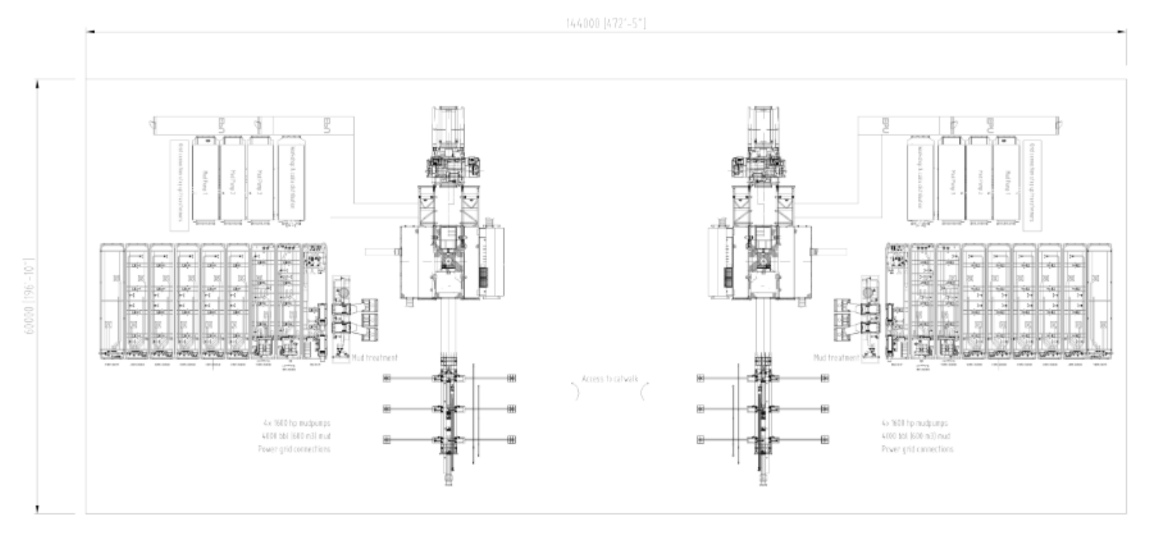

Figure 12: Footprint of 2x standard conventional triple rigs: 144x60 meter (470x200 ft)

Note: this assumes that also the conventional rig can be connected to grid power, which is often not the case due to electronic requirements

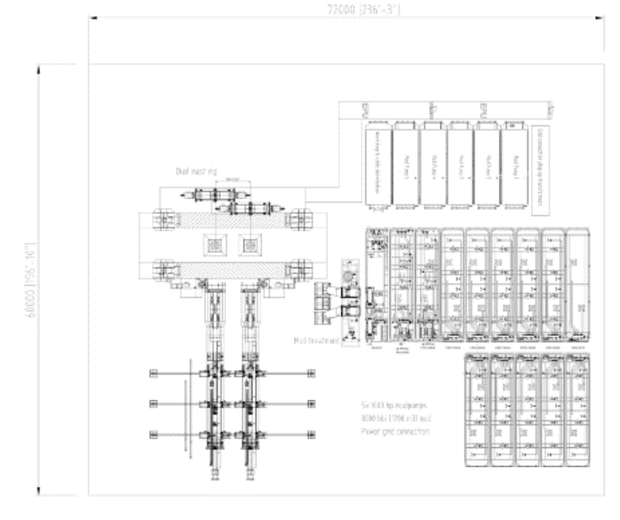

Figure 13: Footprint of 1x XLD90 Dual Derrick: 72x60 meter (235x200 ft)

2.7. CO2 / energy

With providing up to 30% less time per well, the CO2 emissions will also reduce significantly as the rig is operated less days on location.

Also, the InnoRig 90D dual derrick will be designed to be able to connect to grid power instead of diesel-powered generators. This provides the ability to use electricity from renewable resources, reducing CO2 emissions. The regenerative power system re-uses energy that is generated during lowering a load. This is done by the electro motors on the drawworks which will be used as a regenerative braking system. While, on wellcentre A, slowing down or holding the hookload during lowering the pipe into the well, energy is generated and feeded back to the electrical VFD system. This power can then be instantly used by e.g the mudpumps that power the then ongoing drilling on well centre B. By this system, less energy is wasted during operations. A small power storage system as a battery bank can further optimize the flexibility of the system.

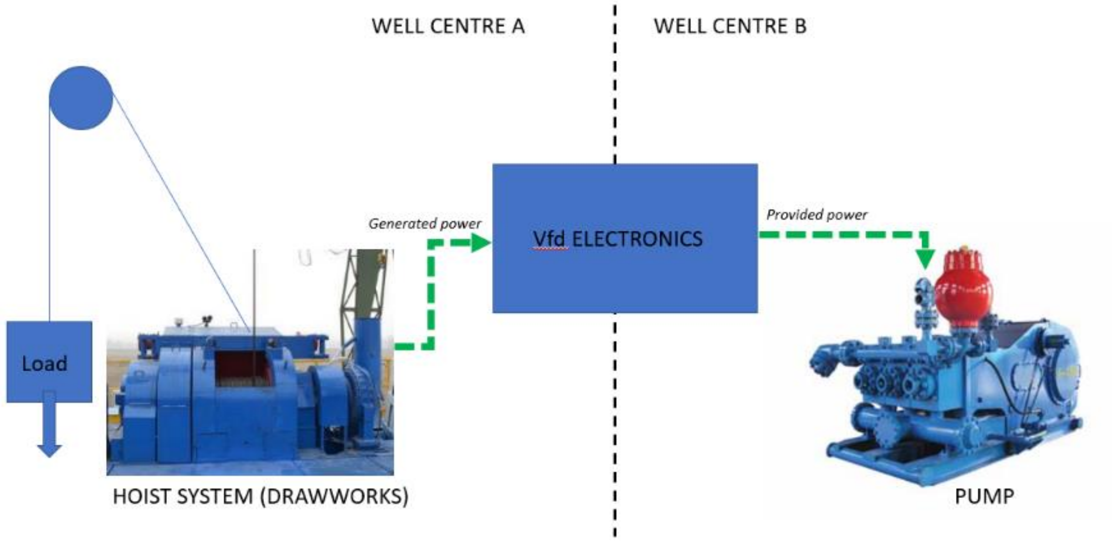

Figure 14: Principle regenerative power on the dual derrick system

3. Conclusion: Time and Cost savings per well

3.1. Scenario: 2 conventional rigs vs 1 dual derrick rig

This scenario assumes that the site layout is quite large and that 2 conventional drilling rigs can be accommodated. This also requires fitting in 2 complete mud systems, pumps etc.

Running 2 conventional drilling rigs is compared with one dual derrick system.

Here the potential time savings are less, in the range of 10-15 days per project of 180 days, so 10%.

But the dual derrick has the ability to drill two wells simultaneously with only one floor crew. This crew is slightly larger the one crew for a conventional rig, but as the crew works for two well centres, the average crew size and costs per well center is significantly less when adding the sum of two conventional rig crews. Also, the footprint for the dual derrick is smaller than for the two separate rigs.

For this study the rig rates are compared between newbuild rigs, so both rates also include depreciation of the assets. The combination of low crew costs, smaller footprint and less time per well translate in a cost saving of around 16%.

- **Reduce the costs per geothermal loop system up to 16%**
- **Save over 10% time per 12 loop project**

3.2. Alternative scenario: 1 conventional rig vs 1 dual derrick rig

After reviewing this scenario, the feedback is that with current downhole tool technologies it is not possible to drill a loop with only 1 single rig. Reason is that the 2 legs need to be drilled simultaneously. In that case in leg A a downhole tool is used that sends out a location signal. This signal is then caught by the downhole tool in leg B, which allows then to steer towards an intersection, therewith creating the loop.

In case in the future it becomes possible to intersect without drilling 2 legs simultaneously, the below scenario would become valid.

This scenario assumes that there is not sufficient space on the location to run two conventional rigs. Or that there is a shortage in the market on skilled people that could operate 2 rigs. The dual derrick has a smaller footprint. It is assumed this does fit on the location.

In this case the 1x conventional rig is less efficient due to the lack of automation which takes approximately 10 additional days per well. Also, the crew size needs to be larger due to the amount of manual work. In addition, 1 rig can only drill approximately half of the number of wells in the time that the dual derrick completes the project.

So summarized the conventional set-up in this case requires more time per well, a larger crew and provides half of the capacity (1 well at a time instead of 2).

Although the rig contractor dayrate of 1 conventional rig is approximately 20% cheaper than the dual derrick rate, the project would require almost 300 days with 1 conventional rig, while the dual derrick completes the task in 170 days.

This time saving of 127 days equals over 40% less time per project.

Apart from the cost saving in contractor dayrate, also the rate, added by the operator to manage the project, is cut by 40%.

Based on the above time savings, the expected costs per project can be reduced by 19%

- **Reduce the costs per geothermal loop system up to 20%**
- **Save over 43% time per 12 loop project**
  - **Provide 43% more geothermal wells per year**
  - **Equals 43% more heat per year**

3.3. Key technical performance indicators:

- **Full automated tripping > 4000 ft/hr (1220 mtr/hr**)
  - Speed is of the essence for deep geothermal wells
- **Fast added pipe during drilling: 85 seconds**
  - **<u>Cut of 15% of current connection time</u>**
  - Close slips, add next pipe, make up all connections, open slips = 85 seconds
  - For reference: Field industry connection standard is 300 seconds
  - Total connection is determined by starting up pumps + mechanical connection
- **Automation and Dual derrick system for reduced crew sizes**
  - Study shows possibility to operate **the 2 rigs with a total crew of 8 people (**so 4 people per well)
  - **<u>Enabling 40% crew costs reduction</u>**
    - Industry standard rig would require at least 2x6 = 12 people
  - 1 remote directional driller for multiple rigs
  - Minimize crew size by combining 2 rigs on 1 floor

4. Further optimization

The described operations provide an indication of the advantages of using a custom automated rig that combines two rigs into one system.

4.1. Rig moves

Beside these efficiency gains, the operations could be further optimized.

The impact of a rig move has not been taken into account. But with dual derrick one can plan one rig move instead of two separate rig moves, which would have been required if two conventional rigs were used on one location. Also with the dual derrick, no infield rig move or rig skidding / walking operation is required between the two vertical wells which saves valuable time and resources. This new approach saves time and resources between two projects.

4.2. Automated mud systems

With drilling 24 horizontal wells in the same area, it can be expected that these operations have large similarities in terms of subsurface formation characteristics. Lessons learned on drilling leg 1 -2 will provide a good basis to optimize leg 3-24. This is valid for drilling parameters but also for mud properties, pressure and flows. The combination of mud pressure, flow and mud properties determine mainly the drilling speed. In most cases the mud property control is in most cases still a manual operation, where mud is manually sampled, weighted and adjusted accordingly by e.g. manually adding bags of additives to the mud by a mixing device. This process of measuring mud properties and adjusting accordingly can be automated. With the lessons learned in real time on drilling leg 1-2 the mud adjusting program can be planned in advance for the other wells. An automated mud mixing system then controls accordingly, with the aim to maximize the drilling efficiency, speed and bit life-time.

Figure 15: Conventional mud property testing with funnel and watch

Figure 16: Conventional mud mixing: add bags manually to a mix hopper

Source: https://www.youtube.com/watch?v=0GVK99g0ppE

Figure 17: Huisman automated mud mix system to automatically adjust mud properties in real time

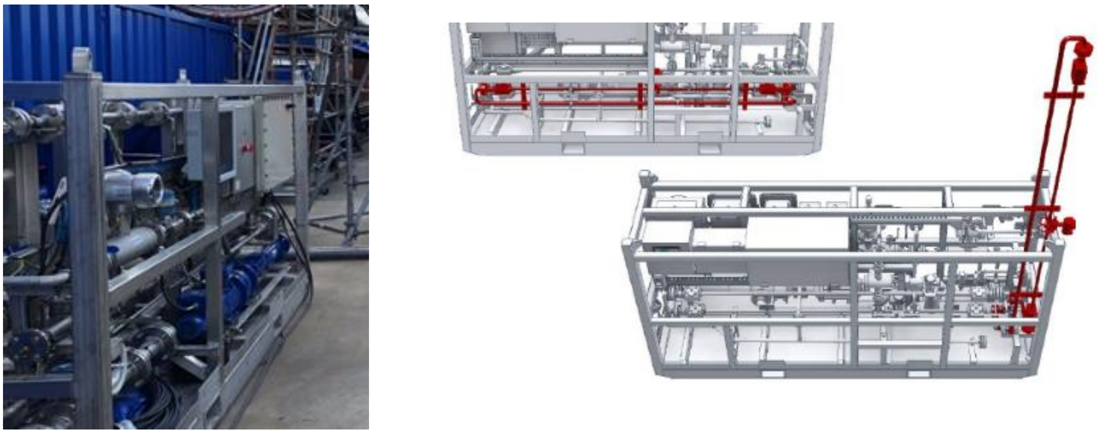

Figure 18: Mud rheology skid: automatically sample and analyse mud properties on the fly

5. Appendix A: Rig description InnoRig XLD90

- Shared setback

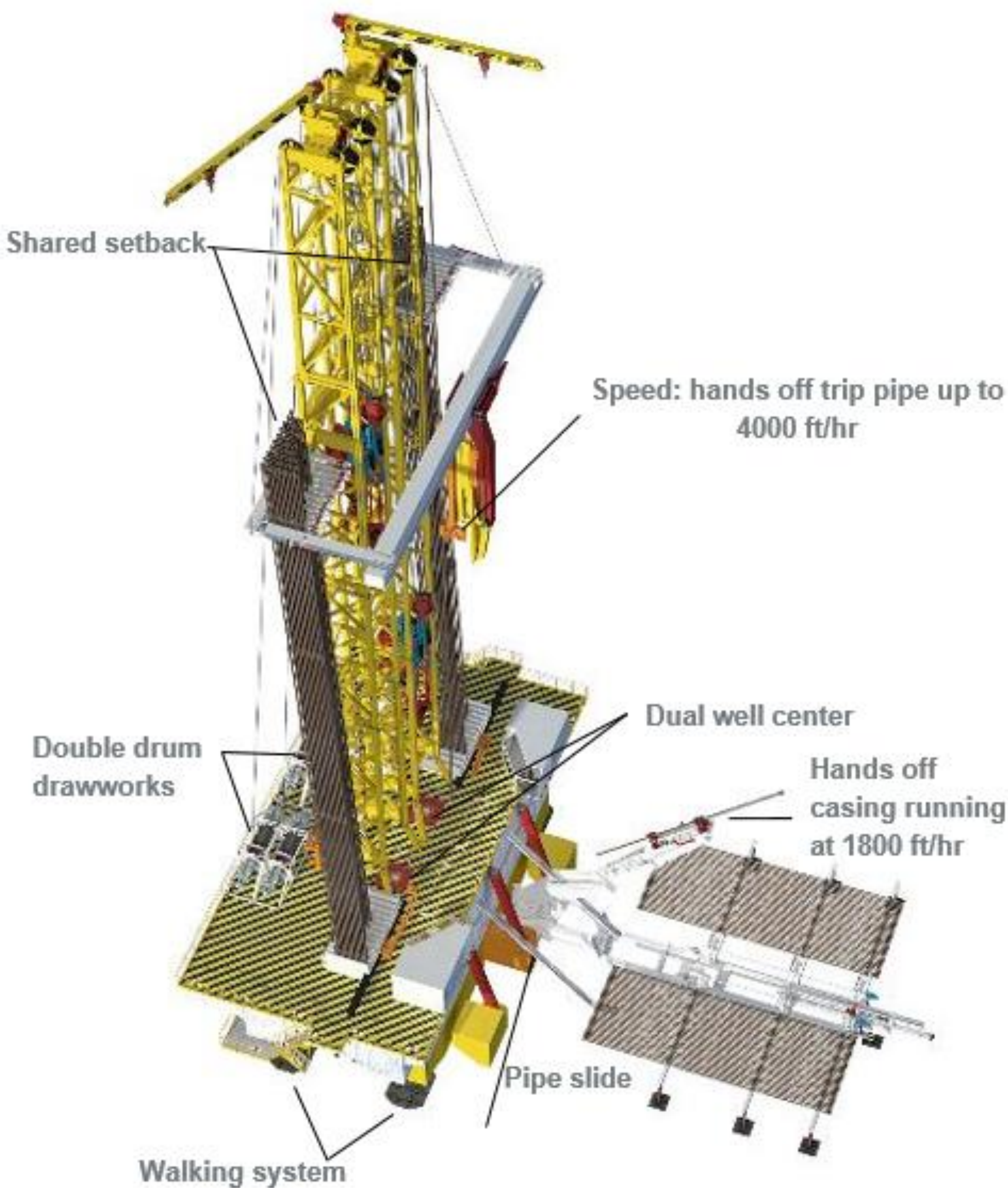

Figure 19: InnoRig XLD90 overview

Figure 20: BOP handling system for two BOPs