الجمهورية الجزائرية الديمقراطية الشعبية
The People's Democratic Republic of Algeria
وزارة التعليم العالي و البحث العلمي
Ministry of Higher Education and Scientific Research
جامعة عمار ثليجي– الأغواط
University Amar Telidji of Laghouat

Faculty : Technology
Departement : Process Engineering
Domain :Science and technology
Field : Hydrocarbons
Speciality :Hydrocarbons and Gas Engineering

Course and Solved Exercises
Bachelor’s Degree in Hydrocarbons and Gas Engineering

Oilfield Equipment I

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Academic year : 2025/2026

Chapter I: General Information on Drilling Equipment.

Chapter II: Hoisting System

Chapter III: Drilling Line

Chapter IV: Drawworks (Hoisting Winch)

Chapter V: Rotary Drilling Materials and Mud Pumps

Introduction

This document, *Oilfield Equipment I*, is designed as a comprehensive course resource for students in hydrocarbon and gas engineering, particularly those pursuing a Bachelor's degree in the field. It covers the fundamental equipment and systems used in oil and gas drilling operations, with an emphasis on technical understanding, practical calculations, and safety considerations.

The content is structured into three main chapters:

- **Chapter I** provides general information on drilling rigs, including their technological functions, technical characteristics (hook load, power, depth, dimensions, mass, pressure, flow rate, and price), classification, fundamental requirements (power, safety, environment, mobility, human factors), and operating modes.
- **Chapter II** focuses on the hoisting system, describing its components (drawworks, crown block, traveling block, drilling line), advantages and disadvantages, kinematic and force analysis, power calculations, and overall efficiency.
- **Chapter III** examines the drilling line in detail, covering construction, stranding and cabling, geometric and resistance characteristics, core types (fiber, IWRC, plastic, and others), preforming, diameter selection based on load/strength relationships, and tonne-mile calculation for work done during hoisting and lowering.
- **Chapter IV – Drawworks (Hoisting Winch)** describes the motion transmission system, main components (frame, drum, shafts, chains), deflection angle requirements, and provides exercises on speed calculations.
- **Chapter V – Rotary Drilling Materials and Mud Pumps** covers the rotary table, kelly, swivel, bushings, reciprocating mud pumps, flow rate and power calculations, pressure losses in drilling circuits, and hydraulic optimization.

The document also includes a set of application exercises with step-by-step solutions to reinforce the theoretical concepts and prepare students for real-world drilling calculations.

This work is intended as a first edition; future versions will be expanded to cover additional topics related to petroleum operations. It is the hope of the author that students will find here the essential knowledge and tools needed for their studies and future careers in the oil and gas industry.

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CHAPTER I:
General Information on Drilling Equipment

I.1 Drilling Rigs :

The role of a drilling rig is to create a connection between a hydrocarbon reservoir and the surface under the best possible technical, economic, and safety conditions.

The choice of a drilling rig is critical. Selecting the optimal rig that meets the power requirements of the drilling program is a constant concern. The goal is to achieve the highest possible quality/price ratio while respecting all safety requirements.

This is because an oversized rig leads to unnecessary additional costs. Conversely, an undersized rig constitutes a permanent risk and can limit pulling capabilities in the event of a stuck drill string.

The capacity of drilling equipment is a function of the drilling technology and process.

A drilling rig is a system of equipment installed at the surface. Its primary function is to carry out all the work directly related to the construction of a well. The rig is composed of several integrated systems that work together to perform the drilling operation.

Mechanical Drilling (Rotary)

Rotation of the tool⇒ Rock destruction⇒ Cuttings evacuation⇒ Advancement into the borehole

In Algeria, the number of phases generally varies between 3 and 6 phases (Fig. I.1).

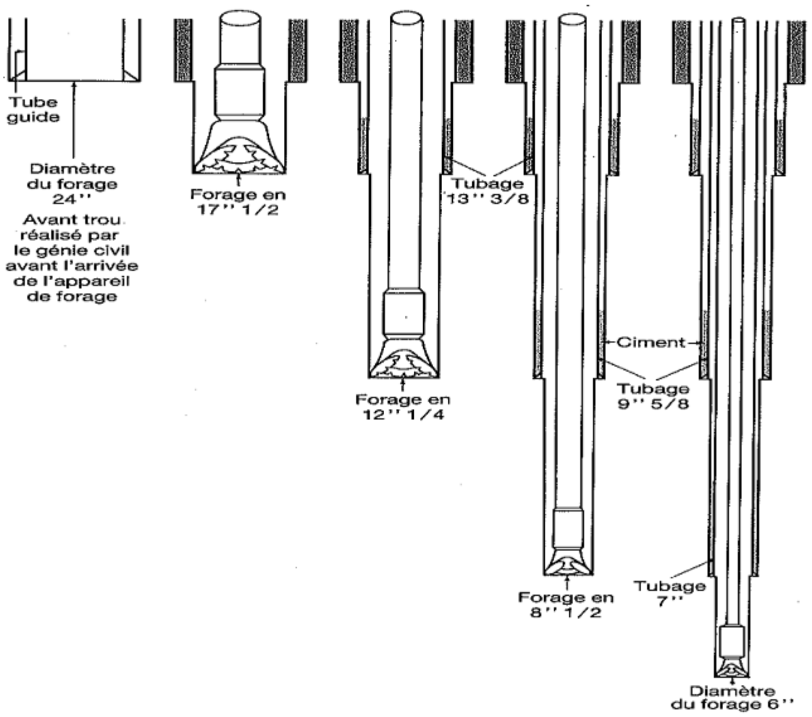


Fig. I.1 :Wellbore Drilling and Casing Schematic

Tripping Operations:

- Handling the toolCasing → Tool replacement

I.2 Technological Functions and Associated Equipment : Table I.1

Technological Function	Principle	Equipment Used (Examples)
1) Rotation	Transmit the torque necessary to destroy the rock.	• **Rotary Table** : Drives the kelly or square drill pipe from the surface. • **Top Drive System** : Used with the drill string to allow rotation and fluid circulation. • **Downhole Motor** (Turbodrill or Electrodrill) : Converts hydraulic or electrical energy into rotation directly above the drill bit.
2) Cuttings Evacuation (Circulation System)	Clean the hole bottom, bring cuttings to the surface, stabilize the wellbore walls, and	• **High-Pressure Circuit** : Includes mud pumps (or compressors for air drilling), hoses, and the swivel. • **Low-Pressure Circuit** : Includes tanks, mud pits, return lines, and ditches.

	cool the bit.	• **Separation Equipment** : Shale shakers, desanders, desilters for cleaning the drilling fluid.
3) Tool Advancement	Control the descent of the drill string to maintain constant weight on the bit.	• **Drawworks** : Handles the raising and lowering of the load. • **Block and Tackle** (Hoisting system): System of pulleys (crown block and traveling block) multiplying the force of the drawworks. • **Automatic Driller** : Regulates the descent speed of the drill string to optimize penetration and avoid overloads.
4) Tripping Operations & Handling	To handle drill pipe, casing, and tools during tripping operations (running in and out of the hole) and to make up or break out connections.	• **Hoisting Equipment:** (See function 1) Drawworks, block, hook. • **Auxiliary Handling Equipment:** - **Power Tongs:** Hydraulic or pneumatic wrenches used to make up (tighten) and break out (loosen) drill pipe connections. - **Slips:** Wedge-shaped devices fitted around the drill pipe to suspend and hold the string in the rotary table. - **Elevators:** Clamps that latch around the drill pipe or casing to support it during hoisting. • **"Tirage" (Pulling):** The operation of pulling the drill string out of the hole, utilizing the full capacity of the hoisting system.
5) Power Supply	To provide the mechanical, electrical, and hydraulic energy required to operate all rig systems.	• **Power Generation Units (Gensets):** Prime movers, typically diesel engines, coupled with generators to produce electricity. • **Transmission Systems:** Devices that transmit power from the prime movers to the drawworks, mud pumps, and rotary table (e.g., electrical cables, hydraulic lines, or mechanical

6) Control and Monitoring	To monitor drilling parameters and control rig operations for safety, efficiency, and precision.	• **Measurement Instruments:** Sensors and gauges monitoring vital parameters such as: - Weight on Bit (WOB) - Hook Load - Rotary Speed (RPM) - Torque - Pump Pressure (Standpipe Pressure) - Mud Flow Rate - Pit Volume (to detect gains or losses) • **Driller's Console:** The central control panel where the driller monitors instruments and controls the drawworks, rotary table, and pumps.

I.3 Technical Characteristics of Drilling Rigs Capacity :

A drilling rig is a complex assembly of **technological, power generation, and auxiliary machinery** installed at the surface (or on a platform).

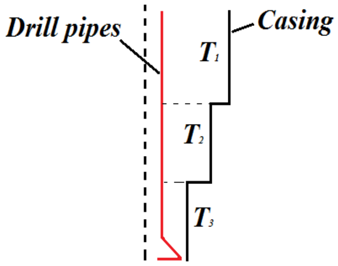
Establishing a clear **classification system** for these machines is essential for making an informed and rational equipment choice. From a technical perspective, such a classification allows engineers to:

- Define the operational limits and capabilities of the rig.
- Match the rig's specifications (hook load, power, pump capacity) to the requirements of the drilling program.
- Ensure safety and efficiency by selecting appropriately sized equipment.
- Optimize the cost-performance ratio of the operation.

I.3.1 Maximum Hook Load: W_{hlmax} (N)

From a physical standpoint, represents the sum of the self-weight of the drill string (drill pipes + casing) and the friction forces or resistance to movement.

In the case of casing running:



The weight of the casing and the drill pipes is calculated.

$$HL_{max} \geq G_{string} + F_{friction}$$

Where:

- G_{string}: Total weight of the string (drill pipes + casing).
- $F_{friction}$: Friction forces during movement (tripping in or out).

Typical Values:

- General Range: HL= (80 to 500)×10^4 N $\begin{cases} \text{HRM'L: } \approx\ 110 \times 104 \text{ N} \\ \text{HMD : } \approx\ 320 \times 104 \text{ N} \end{cases}$

I.3.2 **Total Installed Power: N_ε (kW)**

From a technical point of view, the greater the installed power, the faster operations can be carried out. The available power therefore determines the **speed of execution** of drilling operations.

Typical Values:

- General Range: N_ε =(300 to 3000) kW
- In Algeria: Generally between 1000 and 2000 kW

I.3.3 Drilling Depth :

This depth is determined by the **drill string used** and its **linear weight** (weight per unit length).

If: $q \approx 300$ N/m (linear weight)

Then the maximum depth depends on: $L_{TDS} = \frac{WOB}{q}$

Where:

- G_{DS}: Total weight of the drill string
- L_{DS}: Length of the drill string

Example: Typical Depth Range: $L \approx 1600$ to 3000 m.

I.3.4 Derrick Heights :

Derrick height varies significantly depending on the type of rig (land vs. offshore), its generation, and its operational depth rating. The height is primarily determined by the length of the "stands" of drill pipe it needs to rack (store) vertically.

A standard single joint of drill pipe is approximately **30 feet (about 9 meters) long** . Rigs are often described by how many joints they can stack vertically:

- **Double derricks:** Stack two joints (~60 ft / 18 m stands)
- **Treble derricks:** Stack three joints (~90-100 ft / ~30 m stands)

I.3.5 Dimensions (Envelope/Footprint) of a Drilling Rig :

The **dimensions** (or **envelope**) of a Drilling Rig refer to the set of maximum spatial measurements (length, width, height) occupied by its component parts. This data is considered under two fundamental aspects for logistics and operations:

1. **In the assembled state (working configuration):** The dimensions determine the **installation footprint** and volume required to set up and operate the rig on the drilling site. This includes:
   - The ground footprint of the derrick, power modules, mud circulation systems, and storage areas.
   - The vertical clearance required under the hook and for pipe handling.
   - *Objective:* To ensure that the chosen platform or location has sufficient space to accommodate the equipment safely.
2. **In the disassembled state (transit configuration):** The dimensions define the **transport conditions** for the various modules and sub-assemblies. This takes into account:
   - The maximum dimensions of each package (length, width, height) to verify compatibility with transport means (trucks, trains, barges, cargo aircraft).
   - The weight and center of gravity of each element to ensure stability and safety during lifting and transport.
   - *Objective:* To enable optimal and secure logistics, ensuring that each component can pass under bridges, through tunnels, on roads, or be loaded onto trailers and vessels.

I.3.6 Mass of a Drilling Rig :

The **mass of a Drilling Rig** refers to the total weight of the drilling equipment. It is a fundamental technical specification that, like the rig dimensions, determines two essential aspects:

1. **Material Cost:** The mass directly determines the quantity of steel and components required for construction. The heavier the rig, the more raw materials and sophisticated technologies it requires, which increases its overall cost.
2. **Lifting Capacity:** The structural mass of the rig is linked to its power. A heavier drilling rig is generally designed to support and handle larger working loads (the weight of drill pipes, casings, etc.), which defines its maximum operational capacity.

I.3.7 Drilling Mud Discharge Pressure :

The **discharge pressure** is the **pressure exerted by the drilling mud at the pump outlet** to **lift the cuttings from the bottom of the well back to the surface**.

It is the force that pushes the mud through the entire drilling circuit.

$$P_{discharge} = \text{Total pressure losses in the circuit}$$

Or more simply:

$$P_{discharge}=P_{pipe}+P_{bit}+P_{annulus}$$

Where:

- P_{pipe} : Friction losses as mud flows down the drill pipe
- P_{bit} : Pressure drop as mud passes through the bit nozzles
- $P_{annulus}$: Friction losses as mud rises in the space between the pipe and the wellbore

Table I.2 : Mud discharge pressures by drilling type

Drilling Type	**Typical Pressure**
Water well drilling	10 - 60 bars
Standard oil drilling	200 - 500 bars
Deep drilling	500 - 1000 bars
Ultra-deep drilling	1000 - 2000 bars

I.3.8 Maximum Pump Discharge Flow Rate :

The **maximum pump discharge flow rate** is the **volume of drilling mud pumped per second** (m^3/s) to **clean the well** by lifting cuttings from the bottom to the surface.

It is the **speed of mud circulation** needed to prevent cuttings from falling back down and blocking the hole.

$$\text{Flow Rate}=\text{Annular Velocity}\times\text{Annular Area}$$

- **Annular Velocity** = How fast mud rises (m/s)
- **Annular Area** = Space between drill pipe and well wall (m^2)

Table I.3 : Typical pump discharge flow rates by drilling type

Drilling Type	**Typical Flow Rate**
Small water well	**~0.010 m³/s** (600 L/min)
Standard oil well	**~0.050 m³/s** (3,000 L/min)
Large offshore rig	**~0.200 m³/s** (12,000 L/min)

I.3.9 Purchase Price of a Drilling Rig :

The **purchase price of a Drilling Rig** is the **total acquisition cost** of the equipment, expressed in dollars or euros, which varies mainly according to **three factors**:

1. **Type and size**: A small land rig costs a few hundred thousand dollars, while an ultra-deep offshore platform can reach several hundred million.
2. **Power and capabilities**: The deeper the rig can drill (up to 15,000 m) and the heavier loads it can handle, the higher the price.
3. **Options and included equipment**: Configuration (automation, safety systems, power supply) causes price variations even for the same model.

Table I.4 :Typical purchase prices by drilling rig type

Drilling Rig Type	Typical Purchase Price
Small water well rig	~$50,000 - $100,000
Standard onshore rig	~$500,000 - $5 million
Offshore jack-up rig	~$50 - $200 million
Ultra-dewater semi-submersible	~$500 - $700 million

I.4 Classification of Drilling Rigs : (Table I.5)

Classification Criteria	Existing Variants / Types	Description / Key Characteristics
1. By Well Location	**Onshore (Land Rigs)**	Operate on solid ground. Rigs are transported via road networks and placed directly on the ground. Generally lower operating costs than offshore, faster infrastructure construction .
	Offshore Rigs	Operate in marine environments. Require specialized rig types based on water depth. Transportation of components done via mega-ships. Higher operating costs and operational risks -1. Further subdivided into bottom-supported units (e.g., Jack-ups for shallower water) and floating units (e.g., Semi-submersibles, Drillships for

		deep/ultra-deep water) .
2. By Well Destination / Purpose (Destination du puits foré)	**Exploration Wells**	Wells drilled to discover new hydrocarbon reserves or obtain geological data. High uncertainty, often require coring, slower drilling, higher cost . Includes **wildcats** (frontier areas with little subsurface knowledge) and **appraisal wells** (to assess size and characteristics of a discovery) .
	Production Wells (Development Wells)	Wells drilled to extract oil or gas after a discovery is confirmed. Formation conditions are better understood, drilling is faster, and cost is lower. Primary purpose is hydrocarbon production .
	Injection Wells	Wells drilled to inject water, gas, or steam into the reservoir to maintain pressure and enhance recovery. Can be classified as positive injection (via tubing) or reverse injection (via casing) .
	Stratigraphic Wells	Wells drilled to obtain information about rock layers (strata). Can be further divided into **core holes** (to recover rock cores) and **test wells** (to evaluate formation characteristics).
	Service Wells	Wells drilled for purposes other than production or injection, such as **observation wells** (to monitor reservoir pressure or fluid movement), **water supply wells** (for drilling operations), or **disposal wells** (for waste injection) -2.
3. By Well Trajectory (Based on well destination)	**Vertical Wells**	Traditional well type drilled straight down. Historically the standard, though some deviation is common due to formation characteristics .
	Directional Wells	Wells intentionally drilled along a planned trajectory. Includes **deviated wells** (inclination ≤85°), **horizontal wells** (inclination 86°-120° to increase reservoir exposure), and **extended reach wells** (long horizontal sections) .

	Cluster Wells	Multiple wells (directional + vertical) drilled from a single surface location or platform, common in offshore and environmentally sensitive areas to reduce surface footprint
4. By Drilling Depth (often linked to well purpose)	**Shallow Wells**	Drilling depth < 2,000 meters. Typically for water wells or shallow exploration.
	Medium-Deep Wells	Drilling depth 2,000 - 4,500 meters. Common for standard oil and gas development.
	Deep Wells	Drilling depth 4,500 - 6,000 meters. Require more powerful rigs and advanced technology.
	Ultra-Deep Wells	Drilling depth > 6,000 meters. Require the most sophisticated equipment; exploration wells at this depth are extremely expensive .

I.5 The Fundamental Requirements of a Drilling Rig :

I.5.1 Power and Mechanical Requirements (What it must lift and turn) :

This is the core of the job. The rig must be able to:

- **Lift the load:** It must support the weight of the drill string (kilometers of pipes) and the casing. This is called the load capacity (measured in tons). A drilling rig must meet the requirement of lifting this load without breaking.
- **Provide torque:** The rotation system (rotary table or top drive) must apply enough twisting force (torque) to turn the drill bit and break the rock deep underground.
- **Circulate the fluid:** The high-pressure mud pumps must be powerful enough to pump drilling mud down to the bottom of the well and bring the rock cuttings back up to the surface.

I.5.2 Safety Requirements :

This is where the rules are the strictest and most numerous.

- **The BOP (Blow out Preventer):** This is requirement number one. The rig must be equipped with a well control system (BOP) that works perfectly and is tested regularly. It is the safety device that shuts the well in an emergency to prevent a blowout. Testing requirements are set by standards (like API 53).

Figure I.2: Typical Blowout Preventer (BOP)

- **Explosion-proof safety (ATEX):** In an area where gases (like methane) can come up, all electrical equipment and engines must meet **explosion-proof standards** (ATEX in Europe, NEC in the USA) so they don't create a spark.
- **Worker safety:** The rig must have systems to protect against falls (handrails, anchor points), guards to protect against moving parts (cables, winches), and accessible emergency shutdown systems (ESD).

I.5.3 Environmental Requirements :

Today, a rig must meet increasingly strict rules to protect the environment.

- **Waste management:** The rig must be equipped to handle cuttings (rock waste) and used fluids without polluting the ground. This means using leak-proof tanks and treatment systems.

- **Containment pans:** All areas with fuel, mud, or chemicals must have drip pans or liners underneath to catch any accidental spills.
- **Noise pollution:** In some areas (near homes), the rig must meet noise insulation requirements to reduce engine noise.

I.5.4 Mobility Requirements :

Requirements differ depending on whether the rig is on land (onshore) or at sea (offshore).

- **For a land rig:** It must be able to be taken apart, transported by trucks, and set up again at a new site (modularity requirement). The rigs must meet transportability standards.
- **For an offshore platform:** The main requirement is **stability** against waves and wind, and the ability to isolate the seabed.

I.5.5 Human Requirements :

A rig is nothing without its crew. The requirements also apply to the personnel:

- **Certifications:** The toolpusher, the driller, and the technicians must meet professional certification requirements (e.g., driller's certificate, pressure operations training, etc.).
- **Safety training:** The whole team must complete basic training (e.g., HUET for survival at sea, or basic oilfield training for land).

I.6 Operating Mode of a Drilling Rig :

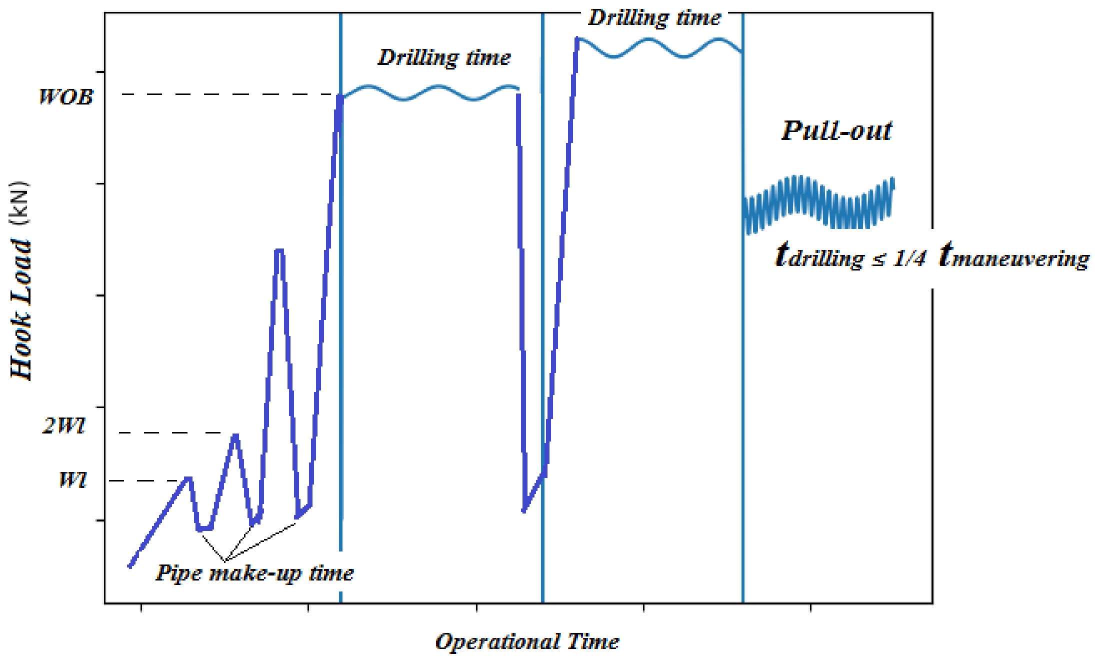


Figure I.3 : Comparative loads and time ratio for drilling operations

Symbols on the Figure :

- **Wl** → Weight of one drill pipe length
- **2Wl** → Weight of two drill pipe lengths
- **WOB** → Drill string weight minus Weight on Bit
- Pull-out (Tripping out)

Dynamic Load :

- The load on the drill string that **varies with time** due to motion, vibrations, or varying forces during drilling operations.
- Associated with **non-zero speed ($v \neq 0$)** and **non-zero acceleration ($a \neq 0$)**.
- Examples: stick-slip oscillations, bit bounce, surge and swab effects.
- In a figure: shown as a fluctuating or wavy line.

Static Load :

- The load on the drill string when the system is **not moving or moving very slowly**, caused mainly by the **weight of the drill string** and applied forces.
- Associated with **zero or negligible speed ($v \approx 0$)** and **zero acceleration ($a \approx 0$)**.
- Examples: during pipe addition, running in hole, or pulling out.
- In a figure: shown as a constant or nearly flat line.

Chapter II:

Hoisting System

II.1 Hoisting Components :

The hoisting system on a drilling rig is the set of equipment used to perform all lifting operations, enabling the raising or lowering of the drill string and other heavy tools into or out of the well. It includes the drawworks, crown block, traveling block, deadline anchor, supply reel, and drilling line. The system multiplies lifting forces to handle very heavy loads, distributes these loads over multiple cable lines to reduce stress on any single line, and increases the speed of the traveling block during operations.

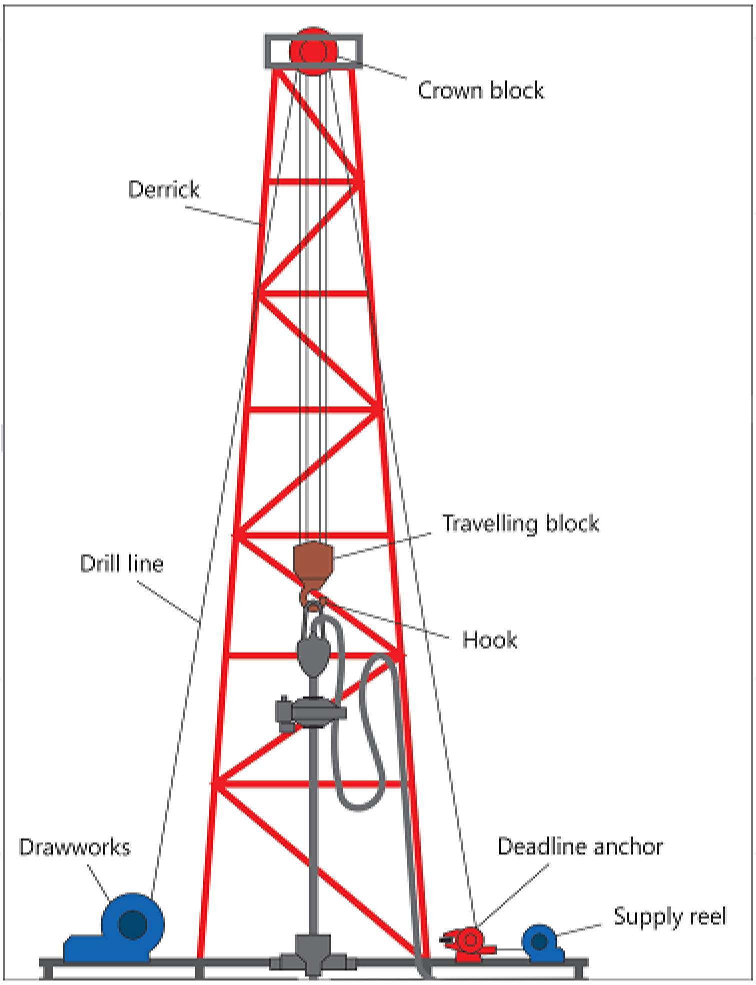


Figure II.1. Hoisting equipment of the drilling rig.

Drawworks is the main operating component of the hoisting system and is used to transmit power from prime movers to the hoisting drum that lifts drill string, casing or tubing string out of and to lower it back into the borehole. They consist of a large diameter steel spool, brakes, a power source and assorted auxiliary devices. The primary function of the drawworks is to reel out and reel in the drill line, a large diameter wire rope, in a controlled manner. The speeds for hoisting the drill string could be changes by driller via integrated gear system.

Crown block is fixed assembly of sheaves (single or double) with a wire rope drilling line running between it and is located at the top of the derrick or mast and over which the drilling line is threaded. It is used to change the direction of pull from the drawworks to the traveling block.

Traveling block and hook combination is used to safely and efficiently raise or lower tools and equipment in the well. It is the set of sheaves or pulleys through which the drill line (wire rope) is threaded or reeved, is opposite the crown block and enabling heavy loads to be lifted out of or lowered into the wellbore. Hook is located beneath the traveling block and is used to pick up and secure the swivel and Kelly.

Deadline anchor is usually bolted on to the substructure and is the equipment that holds down the deadline part of the wire rope. It provides weight measurements and secure deadlines.

Supply reel is a spool that stores the unused portion of the drill line.

Drill line is the wire rope used to support the drilling tools. It is threaded or reeved through the traveling block and crown block to facilitate the lowering and lifting of the drill string into and out of the borehole. Drill line then clamped to the rig floor by the deadline anchor. The drill line can be configured with **N lines**, where NNN ranges from **2 to 12**, corresponding to up to six pairs of lines. The greater the number of lines (and pulleys) in the block and tackle system, the greater its lifting power but at the expense of slower upward and downward movement of the system.

II.2 Advantages of Using a Hoisting System :

1.Multiplication of lifting force

- Enables very heavy loads, such as the drill string, to be lifted with less effort.

2.Improved safety and control

- Reduces the risk of overloading the drill line and helps maintain stable lifting operations.

3.Operational flexibility

- Can handle different load configurations and depths by adjusting the number of lines and blocks.

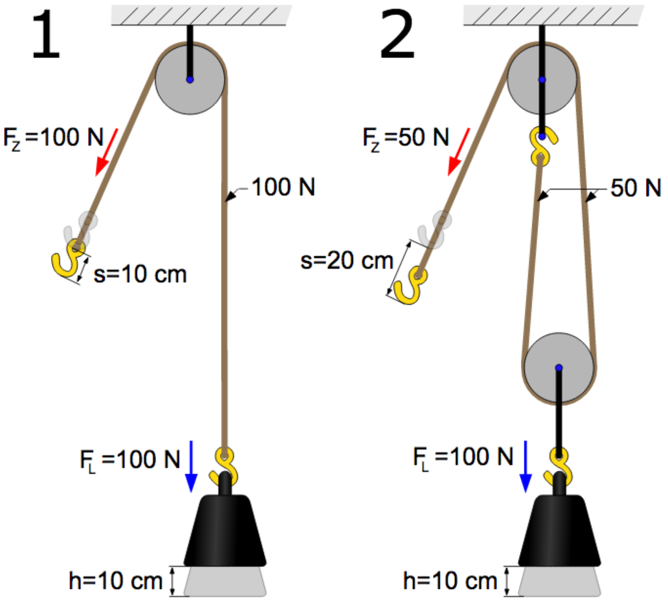


Figure II.2 : Comparison of force and displacement parameters for two loading configurations

II.3 Disadvantages of Using a Hoisting System :

1. **High initial cost**
    - Hoisting equipment, including drawworks, blocks, and drill lines, is expensive to purchase and install.
2. **Complex maintenance**
    - Requires regular inspection and maintenance to avoid failures, especially of pulleys, lines, and bearings.
3. **Space and weight constraints**
    - The hoisting system occupies significant space on the rig and adds weight, which may limit mobility or require reinforced substructures.
4. **Operational complexity**

    - Operating multiple lines and blocks requires skilled personnel; mistakes can lead to accidents or equipment damage.

5. **Friction and energy losses**
    - Multiple lines and pulleys introduce friction, reducing efficiency and requiring more power from the drawworks.
6. **Limited speed for very heavy loads**
    - Even with mechanical advantage, lifting extremely heavy drill strings can be slow due to safety limits.

II.4 Technical parameters of a hoist :

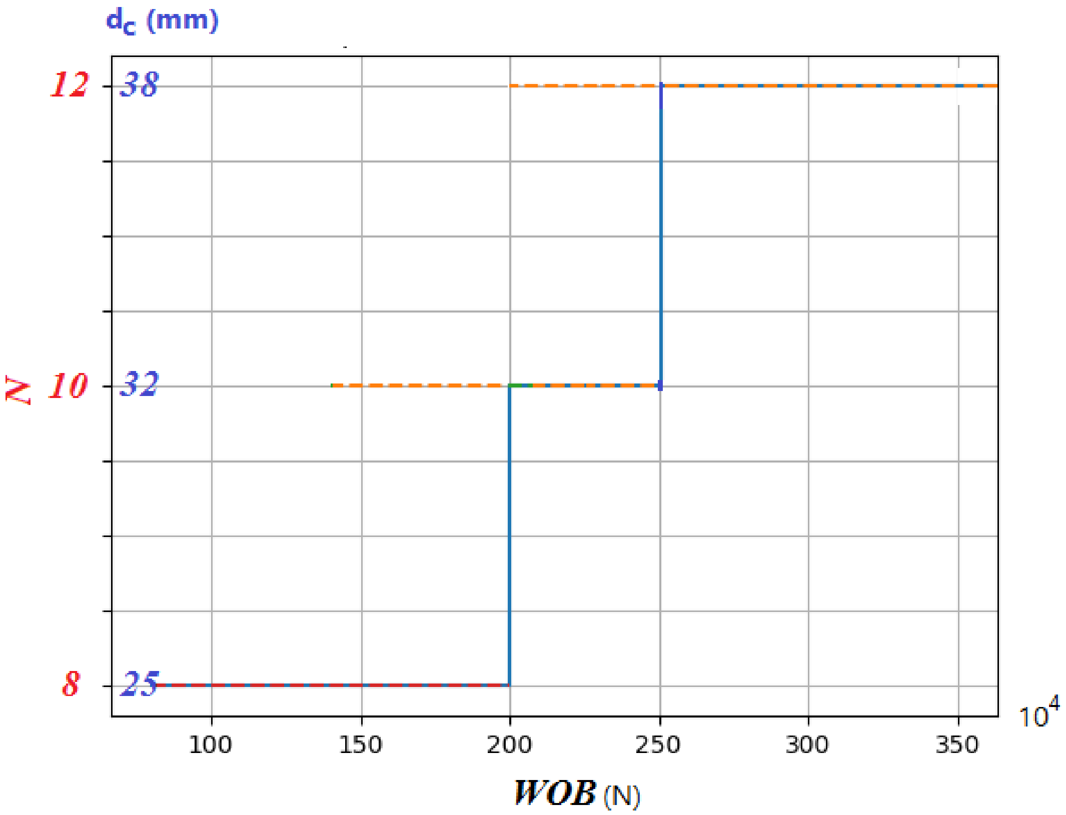


Figure II.3 : Variation of WOB, cable diameter (d_c), and parameter Z with increasing WOB

II.5 Relationship Between WOB, Cable Diameter, and Number of Lines :

The Relationship Between WOB, Cable Diameter, and Number of Lines is Inverted

In a real hoisting system (block and tackle):

- **Higher Load (WOB)** → Requires Thicker cable (larger d_c) AND/OR More lines (larger Z)

- **Lower Load** → Can use Thinner cable AND/OR Fewer lines

II.6 Kinematic Analysis of a Hoisting System (Block and Tackle) :

Definition of the System :

A **mouflage** (hoisting system) consists of:

Fixed pulleys (attached to the derrick/mast)

Movable pulleys (attached to the hook/load)

Cable (drilling line) passing through the pulleys

Z = number of cable lines supporting the load (also called falls or parts of line)

The input data **as:**

- **V** = velocity of the movable pulley block (load/hook velocity)
- **Z** = number of cable lines

Let us calculate V_{al}, V_{ti}, and ω_d that is, the active line velocity, the velocities of the intermediate lines, and the rotational speed.

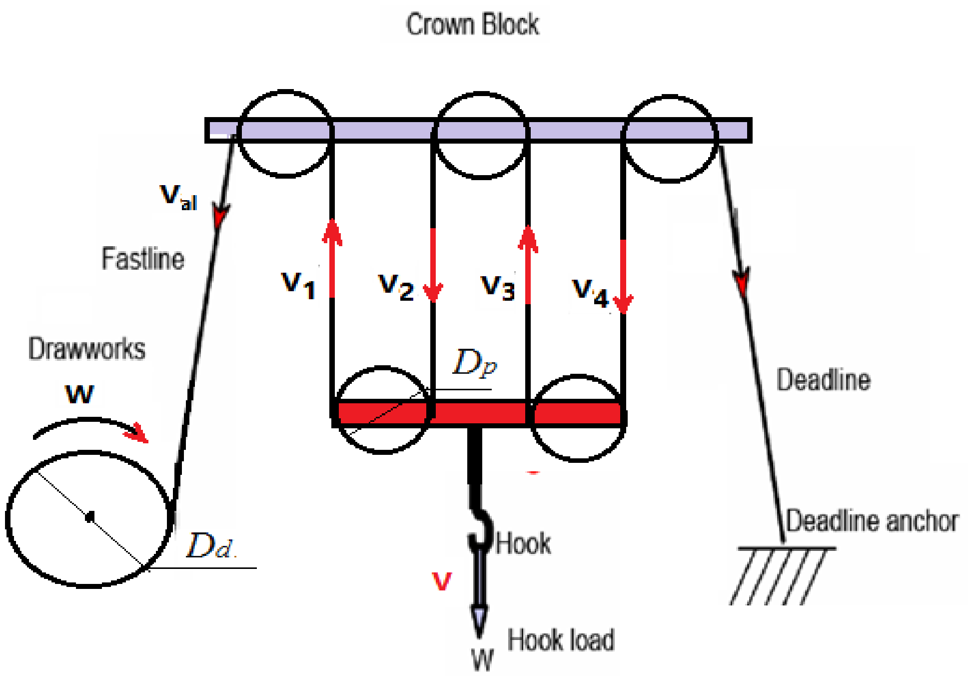


Figure II.4 : Schematic of a drilling hoisting system showing crown block, fast line, drawworks, deadline anchor, and hook load

- D_d : drum diameter, D_p : pulley diameter

Review of kinetics :

1. For two diametrically opposite points on a pulley with a fixed axis, the direction changes (opposite tangents), but the magnitude of the linear velocity remains the same.
2. For two diametrically opposite points on a pulley with a mobile axis, both the direction and the magnitude of the linear velocity (relative to a fixed reference) can be different.
3. The dead line has zero velocity. It is stationary (fixed / anchored)
4. The first pulley is the pulley that rotates faster than the other pulleys.

$$V_{al} = V_1 , \qquad V_2 = V_3 \ , \qquad V_4 = V_{dl} = 0$$

$$\begin{cases} V_{load} = \dfrac{h}{t_1 - t_0} = \dfrac{h}{t_1} \\ h \times Z = S_{ab} \\ V_{al} = \dfrac{S_{ab}}{t_1} = \dfrac{h \times Z}{t_1} \end{cases} \qquad V_{load} = \frac{V_{al}}{Z} \Rightarrow V_{al} = V_{load} \times Z$$

The First Pulley in the Hook (Traveling Block) : $\begin{cases} V_1 = V_{load} + \frac{\omega_p \times D_P}{2} \\ V_2 = -V_{load} + \frac{\omega_p \times D_P}{2} \end{cases}$

$V_2 = V_1 - 2V_{load}$, $\qquad V_2 = V_3$

The Second Pulley in the Hook (Traveling Block) : $V_4 = V_3 - 2V_{load}$

The rotational speed of drawwork : $V_{al} = \omega_d \times 2D_p$, $\omega_d = \frac{V_{al}}{2D_p}$

For : $Z = 4$

$$V_1 = V_{al} = V_{load} \times 4$$

$$V_2 = V_1 - 2V_{load} = 2V_{load}$$

$$V_2 = V_3 = 2V_{load}$$

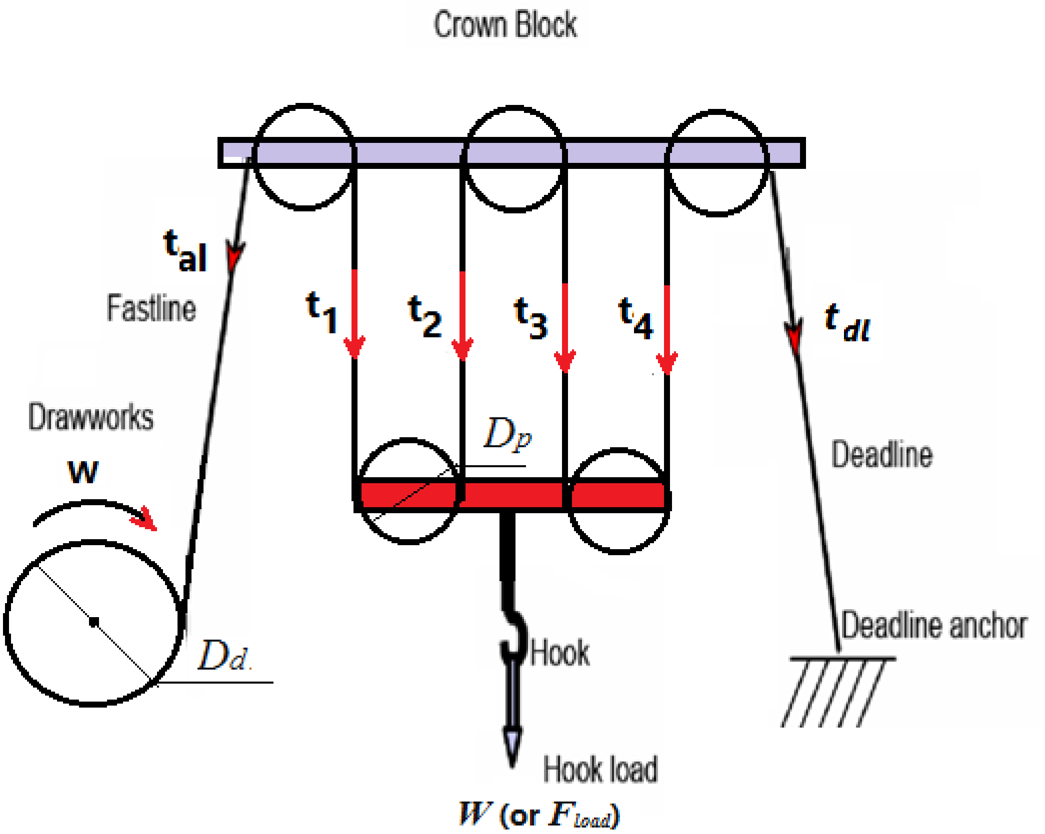
$$V_4 = 0$$

II.7 Force Analysis in a Hoisting System :

Introduction :

The force analysis of a **mouflage** (hoisting system / block and tackle) determines the **tensions** in each cable line, the **load on the hook**, the **fast line tension**, and the **forces on the pulleys and supports.**

W (or F_{load})



FigureII.5 : Force analysis of a drilling hoisting system showing tensions in fast line, active lines, and deadline line

The input data as:

W : Hook load (total weight lifted) (N)

Z : Number of cable lines.

To calculate:

- t_{al} = Tension in the fast line (active line)
- t_i = Tension in line i (where i = 1, 2, 3, ..., Z)
- η_m overall hoisting system efficiency

Depending on the direction of motion of the hook load, the energy behavior of the hoisting system changes as follows:

- **Case 1:** $V_{load}>0$ (load moving **upward**) **Energy consumption** (lifting)
- **Case 2:** $V_{load}=0$ (load **stationary**) **No energy consumption** (holding)
- **Case 3:** $V_{load}<0$ (load moving **downward) Energy dissipation (braking)** or **energy regeneration**
- Tensions vary from the fast line (index 1) to the dead line (index Z) due to pulley friction. The relationship between successive tensions is:

  $t_{i+1}=t_i\times\eta_p$ (when load moves upward)

  $t_{i+1}= t_i/\eta_p$ (when load moves downward)

Case 1: Load Moving Upward ($V_{load}>0$)

Step 1: Calculate t_{al} (fast line tension)

Using static equilibrium:

$W=t_1+t_2+t_3+\cdots\ldots+t_Z$

η_p = efficiency per pulley (typical 0.96–0.98)

With : $t_1=t_{al}\times\eta_p$ $t_2=t_{al}\times{\eta_p}^2$ ..... $t_{z-1}=t_{al}\times{\eta_p}^Z$:

$$W=\eta_p t_{al}\left(1+\eta_p+{\eta_p}^2+\cdots.+{\eta_p}^{Z-1}\right)$$

$$t_{al}=\frac{W}{\eta_p\left(1+\eta_p+{\eta_p}^2+\cdots.+{\eta_p}^{Z-1}\right)}$$

$$\boldsymbol{t_{al}=\frac{W(1-\eta_p)}{\eta_p(1-{\eta_p}^Z)}}\quad \textbf{\textit{(V}}_{\textbf{\textit{load}}}\textbf{\textit{=constant and a=0)}}$$

$$\boldsymbol{t_{al}=\left(1+\frac{a_{load}}{g}\right)\frac{W(1-\eta_p)}{\eta_p(1-{\eta_p}^Z)}}\quad \textbf{\textit{(}}\boldsymbol{V_{load}}\ \textbf{\textit{≠constant and a= constant)}}$$

Load on the Fixed Pulley Block (Crown Block)

$F_{crow}=T_{al}+t_1+t_2+t_3+\cdots\ldots+t_Z+t_{dl}$

$$F_{crow}=t_{al}\left(1+\eta_p+{\eta_p}^2+\cdots.+{\eta_p}^Z+{\eta_p}^{Z+1}\right)$$

$$F_{crow}=t_{al}\frac{\left(1-{\eta_p}^{Z+2}\right)}{\left(1-\eta_p\right)}$$

II.8 Power Calculation – Power at the Hook :

Definition :

The **power at the hook** is the mechanical power delivered to the load (drill string, casing, etc.) by the hoisting system.

$$P_{Hook} = W \times V_{load}$$

Where:

- P_{Hook} = Power at the hook (Watts)
- W = Hook load (weight being lifted) (Newtons)
- V_{load} = Velocity of the traveling block (hook speed) (m/s)

$$P_{Hook} = P_{fast} \times \eta_m$$

Where:

- $P_{fast} = t_{al} \times V_{al}$ power at the drawworks (fast line)
- η_m = overall hoisting efficiency

*II.9 **Total Efficiency of a Hoisting System :***

Definition :

The total efficiency η total (or η_m) of a hoisting system is the ratio of the output power at the hook to the input power at the fast line (drawworks).

$$\eta_m = \frac{P_{Hook}}{P_{fast}}$$

Relationship with pulley efficiency and number of lines :

For a hoisting system with:

- Z : number of cable lines supporting the load
- η_p : efficiency of **one pulley** (sheave) – typically 0.96 to 0.98

The total efficiency of the **block and tackle** (mouflage) is given by:

$$\eta_m = \frac{\eta_p(1 - {\eta_p}^Z)}{Z(1 - \eta_p)}$$

This formula assumes:

- All pulleys have the same efficiency η_p
- The system is **ideal** in terms of cable stiffness (only friction losses)
- The load is moving **upward** at constant speed (worst-case for efficiency)

II.10 Drawworks output powerP_{do} :

$$P_{do} = \frac{(t_{load} + t_0) \times 1000 \times V_{load}}{75} \text{ (metric } hp)or(Ch)$$

- t_{load} : hook load (tonnes)
- t_0 : weight of hook, traveling block, and accessories (tonnes)
- V_{load} = hoisting speed (m/s)
- 1000 converts tonnes to kg (which gives kgf under standard gravity)
- 75 converts kgf·m/s to metric horsepower (1 hp = 75 kgf·m/s)

For **real power** including friction in the block and tackle, divide by the total efficiency η_m:

$$P_{d,real} = \frac{(t_{load} + t_0) \times 1000 \times V_{load}}{75\eta_m} \text{ (metric } hp)$$

II.11 Drawworks input power P_{di} :

$$\boldsymbol{P_{di} = \frac{P_{d,real}}{\eta_d}}$$

$\eta_d = 0{,}97^3 = 0.912673$ drawworks efficiency (product of drum efficiency, chain & sprocket efficiency, and bearing efficiency).

- **Case 2: Load Stationary (*Vload*=0)**

  No kinetic friction, all tensions equal:

$$t_{al} = t_1 = t_2 = \cdots \ldots \ldots .. = t_z = \frac{W}{Z}$$

Chapter III:
Drilling Line.

The drilling line acts as a flexible link between the block and the drum. This flexibility allows the rotational motion (of the drum) to be converted into the rectilinear motion of the hook. The drilling line is made of alloy steel with carbon, manganese, silicon, chromium, and sometimes nickel – carefully controlled to achieve high strength, fatigue resistance, and wear resistance.

III.1 Construction :

The primary constructions for drilling lines are all within the 6-strand classification, indicating they are composed of six strands wrapped around a central core. The choice of construction directly affects performance: a rope's flexibility increases with the number of wires, but its resistance to abrasion and crushing decreases.

III.2 Stranding and Cabling :

Stranding and cabling are the two fundamental operations in manufacturing a wire rope. For drilling lines subjected to extreme stresses, precise control of these operations defines performance, durability, and safety.

III.2.1 Stranding: Assembling the Wires :

Stranding is the first step: twisting individual steel wires together to form a strand. Definition & Purpose: A strand is a helical assembly of steel wires around a central core. Its role is to distribute the load and provide the rope's basic structural building block.

Table III.1 : Strand Types – The arrangement of wires defines the strand construction, each offering a unique compromise between different properties:

Strand Type	Code	Description	Key Property

Standard (Ordinary)	M	All wires same diameter; point contacts between layers	High stiffness, crush resistant
Seale	S	Large outer wires over smaller inner wires	Excellent abrasion resistance – common for drilling lines
Filler	F	Small filler wires fill gaps between inner and outer layers	High metallic density – good balance of flexibility and strength.
Warrington	W	Alternating large and small wires in the outer layer	High flexibility
Warrington-Seale	WS	Combines Warrington and Seale patterns in a three-layer strand	Flexibility + wear/crush resistance

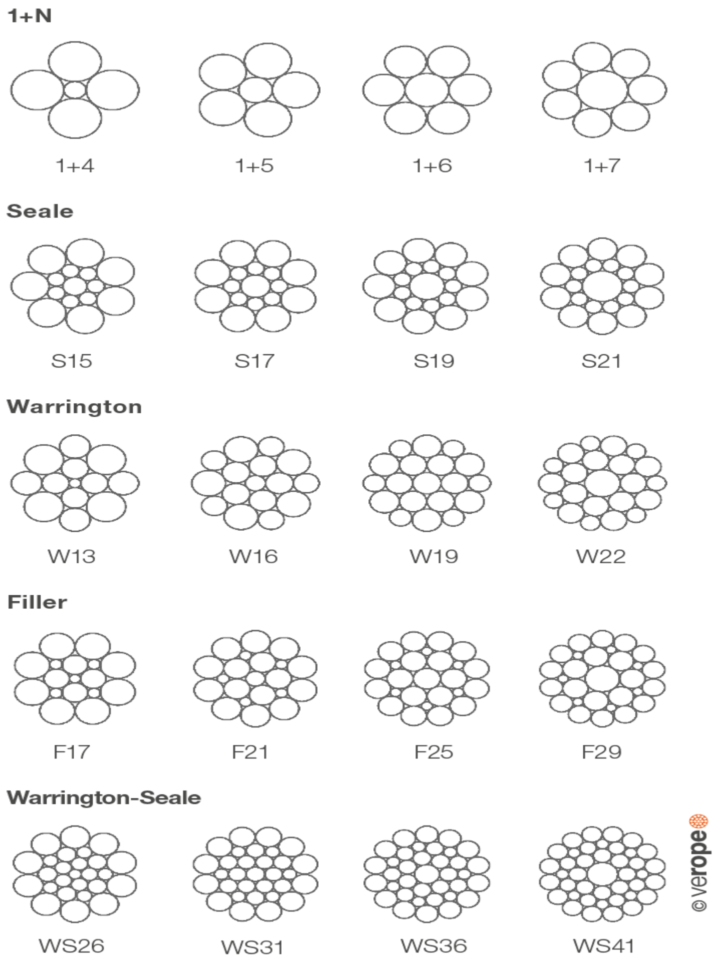


Figure III.6 : Different Types of Strands

III.2.2 Cabling: Assembling the Strands :

Cabling is the second step: preformed strands are twisted together helically around a central core to form the wire rope. Definition & Purpose: Cabling is the final step that gives the complete rope its structure. It determines overall flexibility and the rope's tendency to rotate under load.

Table III.2 : Cabling (Lay) Types – The key parameter is the relationship between the direction of wires in the strand and the direction of strands in the rope:

Lay Type	**Description**	**Advantage**
Regular Lay (Cross lay)	Wires laid opposite direction to strands	Excellent stability, crush resistance, and resistance to kinking – standard for drilling lines
Lang Lay	Wires laid same direction as strands	Greater flexibility, smoother surface, better abrasion resistance – but may generate torque and be harder to handle

Lay Direction – Added to the lay type, defined by the helical direction:

- Right Lay (Z): Strands twist clockwise (most common)
- Left Lay (S): Strands twist counterclockwise

III.3 Geometric Characteristics : tableIII.3

Parameter	**Symbol / Formula**	**Description & Significance**	**Typical Values / Notes**
Nominal Diameter	d_c	The main diameter of the cable, which must match the grooves of the sheaves and drum.	Expressed in mm or inches (e.g., 1 1/4", 1 3/8").
Wire Diameter	d_f	The diameter of the individual wires that make up the strands.	Depends on the strand pattern (e.g., Seale, Filler) and cable size.
Theoretical Section	$A_t = \frac{\pi \mathrm{d}_\mathrm{c}^2}{4}$	The total area of a solid circle with the same diameter as the cable.	Serves as a reference for calculating other parameters.
Real Metal Section	A_m	The sum of the cross-sectional areas of all the steel wires in the	Always less than A_t due to the spaces

		cable.	between wires.
Section Ratio	$R_s = \frac{A_m}{A_t}$	The ratio between the real metal section and the theoretical section. This is a key indicator of the cable's metallic density.	Typically ranges from 0.4 to 0.65 depending on the construction.
Flexibility Coefficient	$K_f = \frac{d_f}{d_c}$	An indicator of the cable's flexibility; inversely proportional to its bending stiffness.	A higher K_f means greater flexibility, which is influenced by the number of wires and the type of lay.
Stranding Angle	α	The angle formed by a wire in the strand relative to the strand's axis. This angle determines the strand's mechanical properties.	Varies depending on the strand pattern (standard vs. parallel). Typically ranges between 16° and 22°.
Cabling Angle	β	The angle formed by a strand in the cable relative to the cable's axis. This angle, along with the pitch, determines the cable's stability and torque behavior.	For standard cables, the sign of β differs from the stranding angle's sign in regular lay cables.
Stranding Pitch	p_s	The axial length required for one complete revolution of a wire around the strand's core.	A shorter pitch (tighter twist) increases stability but reduces flexibility.
Cabling Pitch	p_c	The axial length required for one complete revolution of a strand around the cable's core.	–

III.4 Resistance Characteristics of a Drilling Line – Formulas :Table III.4

Parameter	Symbol	Formula	Notes
Breaking Limit (Tensile Strength)	R_m	$R_m = \frac{F_{max}}{S_0}$	F_{max}: Maximum tensile force before failure (N); S_0: Original cross-sectional area of the steel wire (mm²); Material property, not rope property.
Theoretical Breaking Load	TBL	$TBL = k \cdot \Sigma F_w$	k: Stranding loss factor (typically 0.85–0.90); ΣF_w: Sum of minimum breaking forces of all individual wires.
Totalized Breaking Load	TBL_{iso}	TBL_{iso}= measured value (ISO 7539)	Breaking force of each individual wire measured separately; This is a measured value, not calculated.
Actual Breaking Load	MBL	$MBL = \eta \cdot TBL$	η: Rope efficiency factor (0.80–0.90 for standard round strand ropes); Alternative: $MBL = C \cdot R_r \cdot d^2$ where C = fill factor, R_r = rope grade, d = rope diameter.
Relative Elongation	ε	Elastic stretch: $\varepsilon_{el} = \frac{F \cdot L}{E \cdot A_m}$; Total elongation: $\varepsilon_{tot} = \varepsilon_{el} + \varepsilon_{constr}$	F: Applied tensile load (N); L: Rope length (mm); E: Modulus of elasticity (typically 140–165 GPa for steel wire rope); A_m: Metallic cross-sectional area (mm²); ε_{el}: Elastic elongation (reversible); ε_{constr}: Constructional stretch (0.25–1.0%, permanent).

III.5 Different Natures of the Central Core :

The choice of the central core (or "heart" of the rope) is fundamental because it determines the strength, flexibility, and ability of the rope to withstand the extreme stresses of drilling. Several core types exist, with very different performance characteristics.

III.5.1 Fiber Core (FC) :

This core is made of natural fibers (such as sisal or manila hemp) or synthetic fibers (such as polypropylene), forming a flexible center for the rope.

Advantages: Very flexible, making the rope easy to handle and pass over sheaves. Additionally, it is impregnated with lubricant that it gradually releases, ensuring continuous internal lubrication of the strands.

Disadvantages: Low resistance to crushing; deforms easily under heavy loads, which is problematic for spooling on the drawworks drum. Sensitive to heat and moisture.

Mechanical contribution: This core does not contribute to the rope's breaking strength.

III.5.2 Independent Wire Rope Core (IWRC) :

This is the king of cores for modern drilling lines. It consists of a real miniature wire rope that serves as the core for the main rope.

Advantages: Excellent crushing resistance, allowing it to withstand extreme radial pressures and multi-layer spooling on the drum. Maximum stability, maintains the rope's shape perfectly. Also offers high heat resistance, an advantage for operations where the rope may heat up.

Disadvantages: Makes the rope less flexible and heavier than other core types, and cost is higher.

Mechanical contribution: This core actively contributes to the rope's breaking strength, representing up to 7.5% of the total breaking load. IWRC ropes generally have a longer service life in heavy-duty applications like drilling.

III.5.3 Plastic Core (Polymer Core) :

This is a solid or profiled polymer core (often polyethylene, polypropylene, or nylon), extruded at the rope's center. Sometimes called Polymer Core or Solid Plastic Center.

Advantages: Very good resistance to chemical corrosion (acids, aggressive drilling muds) and moisture – far superior to natural fibers. Lightweight and provides acceptable flexibility while maintaining a stable shape. Can be formulated to withstand moderate temperatures.

Disadvantages: Crushing resistance remains limited (lower than IWRC and even WSC). Under high radial loads (multi-layer spooling on a drum), it can deform plastically. Does not contribute to the rope's mechanical strength.

Mechanical contribution: None, like fiber core.

Use in drilling: Very rare for main drilling lines, but sometimes used for tool lines or auxiliary lines in highly corrosive environments.

III.5.4 Other Core Types (WSC, Solid, Mixed) :

Beyond fibers, IWRC, and plastic, there are other core types, less common for drilling lines.

- Wire Strand Core (WSC): A simple steel strand serving as the core. Provides good strength but less crushing resistance than IWRC.
- Solid Steel Core: Extremely rigid, used for very specific applications where any deformation is prohibited.
- Mixed Core (Fiber + Metal): Combines textile and metal (often a central strand surrounded by fibers) to achieve intermediate properties.

For modern drilling lines (main hoisting rope), the Independent Wire Rope Core (IWRC) remains the universal choice, because its robustness and stability are essential to withstand intense loads and drum storage. The plastic core is a very marginal alternative, reserved for special cases where chemical corrosion dominates and crushing loads are low.

III.6 Preforming

Preforming is a crucial manufacturing process for drilling lines. It's the technique of permanently shaping the wires and strands into their final helical form before the rope is assembled. This significantly improves the rope's internal properties, making it more durable and safer for heavy-duty operations like drilling.

III.6.1 What is Preforming?

In standard rope manufacturing, wires and strands are forced into a helical shape during assembly, which creates significant internal stresses and a tendency to unravel. The preforming process solves this by preshaping each component first. The wires and strands are given their permanent, relaxed helical form before being laid together, resulting in a rope that is naturally "set" in its shape. This produces a rope that is stable, flexible, and free of damaging internal forces.

III.6.2 Key Benefits of Preformed Drilling Lines :

Using a preformed rope provides a range of critical operational advantages:

- Superior Flexibility: Preformed ropes are much more flexible, allowing them to bend easily around sheaves and drums with less resistance.
- Increased Fatigue Life: The reduced internal stress gives preformed ropes greater endurance to repeated bending, leading to a longer service life.
- Ease of Handling and Safety: Unlike non-preformed ropes, a preformed rope will not unravel when cut, eliminating the need for time-consuming seizing and greatly improving handling safety.
- Reduced Internal Stress: Since the components are pre-shaped, they are laid in place without force. This evenly distributes loads, reduces unbalanced wire stresses, and results in a higher safety factor.
- Better Kink Resistance: They are far less likely to form kinks or loops during installation or operation, preventing premature failure.

III.6.3 How the Preforming Process Works :

During manufacturing, each wire and strand passes through a preforming head before the final closing operation. This device permanently bends the steel into the exact spiral it will have in the final rope, setting the components into a stress-free state.

III.7 Diameter Selection – Load / Strength Relationship :

III.7.1 Required Minimum Breaking Force (MBF) :

MBF = Maximum anticipated load × Design factor (III.1)

Design factor for normal drilling: 5 (relative to the minimum breaking force of the new rope).

That is: MBF = 5 × (Maximum anticipated load) (III.2)

Operational safety factor (API RP 9B): Safety Factor = MBF / Maximum fast line tension

III.7.2 Minimum nominal diameter (approximation) :

Based on the desired breaking load, API tables are used. An approximate formula for an EIPS (Extra Improved Plow Steel) rope is:

$$d_c = \sqrt{\frac{4 \times MBF \times K_f}{\pi \times R_m}} \qquad (\mathrm{III.}3)$$

Where:

- d_c = nominal rope diameter (mm)
- MBF: **minimum breaking force** (N)
- R_m = tensile strength of the steel grade (1960 MPa for EIPS)
- K_f = fill factor (≈ 0.55 to 0.65 for a 6×19, 6×36, IWRC)

In practice, tables from API Spec 9A are used.

III.8 Work of the Drilling Line – Tonne-Mile Calculation :

The work T_m transmitted by a drilling cable during a **complete operation (hoisting + lowering)** represents the total energy required by the hoisting system to move the drill string and associated equipment in the well.

III.8.1 Definition of Parameters :

- L: initial well depth at start of operation (m)
- l: stand length (single pipe length) (m)
- w_p: average drill pipe weight per meter in mud (kg/m)
- W_m: weight of traveling block, hook, and accessories (kg)
- d: additional load due to mud / drill collars (kg equivalent)
- 0.981: gravity conversion factor
- 10^{-6}: unit conversion factor (to daN·km)

III.8.2 Hoisting Work (Upward Movement) :

During hoisting, the work increases progressively with each stand of pipe.

III.8.3 Work During Raising (W_{hoist}) :

During hoisting, the work increases progressively with each stand of pipe.

Work for each stand n:

$$W_{\text{hoist}} = 9.81 \times \left[n w_p l + w_p . l^2 \frac{n(n+1)}{2} + n \cdot d \cdot L) \right] \qquad \text{(III.4)}$$

Using n = L/l and simplifying:

$$W_{\text{hoist}} = 9.81 \times \left[\frac{w_p}{2} l(L+l) + L(W_m . + d) \right] (\text{N} \cdot \text{m}) \qquad \text{(III.5)}$$

III.8.4 Work During Lowering (W_{lower}) :

By symmetry, the lowering work is expressed as:

$$W_{\text{lower}} = 0.981 \times \left[\frac{w_{\text{p}} \times \text{L(L+l)}}{2} + 2\text{L}(W_{\text{m}+} 0.5 \cdot d \cdot L) \right] \times 10^{-6} \qquad \text{(III.6)}$$

III.8.5 Total Work for the Complete Maneuver :

The total work for one complete round trip (raising + lowering) is given by:

$$W_{\text{total}} = W_{\text{hoist}} + W_{\text{lower}} = 2 \times W_{\text{hoist}} = 2 \times W_{\text{lower}} \qquad \text{(III.7)}$$

Substituting the expressions for W_{hoist} and W_{lower}, and converting to the desired units (daN·km), the formula becomes:

$$W_{total} = 0.981 \times \left[w_p \times L(L+l) + 4L(W_{m+} 0.5 \cdot d) \right] \times 10^{-6} \quad (10^3 \text{daN. km}) \text{ (III.8)}$$

Where:

- w_{p} = weight of traveling block, hook, and accessories (kg)
- L = depth / hoisting length (m)
- d = additional distributed load (daN or correction term)
- W_{m} mean hook load (daN)

This formula is used to calculate the cumulative work transmitted by the drilling line, which helps schedule slip and cut operations.

III .9 Application Exercises :

Exercise 01 :

During an 8½" phase at a depth of 1600 m, the mud density is d = 1.33. The work done by the drilling line during one lowering operation is 97 (10^3 daN·km).

Given:

- Stand length l = 27 m
- Mass of traveling block and accessories W_m = 8.5 tonnes
- Total mass of drill collars (including tool joints) in mud = 24 tonnes

Calculate:

1. Linear mass of drill pipes in mud w_p
2. Linear mass of drill pipes out of the hole (w_{air})
3. Total mass of drill pipes in mud

Solution :

The formula for total work for a complete maneuver (hoisting + lowering) is:

$$W_{total} = 0.981 \times \left[w_p \times L(L + l) + 4L(W_m + 0.5 \cdot d)\right] \times 10^{-6} \quad (10^3\text{daN.km})$$

- L : depth at start of maneuver (m)
- l :stand length (m)
- d : additional weight in mud due to drill collars (kg)
- w_p : average linear weight of drill pipes (including tool joints) in mud (kg/m)
- W_m : weight of traveling block, hook, and accessories (kg)

The work (Tm) transmitted by a cable for a complete maneuver (lifting and lowering), W_{total} = 97 × 2 = 194 (tonne).

1. Linear mass of drill pipes in mud (w_p**)**

$$W_{total} = 0.981 \times \left[w_p \times 1600(1600 + 27) + 4 \times 1600(8500 + 0.5 \cdot 24000)\right] \times 10^{-6} \quad (10^3\text{daN.km})$$

$$194\times 10^{+6} = 2553739.20\times w_p + 128707200$$

$$(194000 - 128707.2) \times 10^{+3} = 2553739.20\times w_p$$

$$w_p = \mathbf{25.57\ kg/m}$$

2. Linear mass of drill pipes out of the hole : (w_{air}**)**

$$w_{air} = \frac{w_p}{\mathrm{f}} \text{ (kg/m)}$$

Buoyancy factor : $f = 1 - \frac{d_{mud}}{d_{steel}}$

d_{mud}: **mud density** $= 1.33$, d_{steel} : steel density $= 7.8$

Buoyancy coefficient : $f = 0.83$

Linear mass of drill pipes out of the hole $w_{air} = \frac{25.57}{0.83} = \mathbf{30.81\ kg/m}$

3. Total mass of drill pipes in mud ;

$$Total\ mass = w_p / L = 25.57 \times 1600 = \mathbf{40\,912\ kg}$$

Exercise 02 :

During a vertical drilling operation, the drill string is suspended by a drilling line that passes through a **crown block and traveling block** with **8 lines** (8 cable strands supporting the load). The work transmitted by the drilling line during one **complete maneuver** (lifting + lowering) is recorded.

Given:

- Depth at start of maneuver: L = 1800 m
- Stand length: l = 27m
- Mud density: ρ_m = 1.38 g/cm^3
- Steel density: ρ_s= 7.85g/cm^{3}Linear mass of drill pipes **in air** (including tool joints): w_{air} = 32.5kg/m
- Mass of traveling block + hook + swivel: W_m= 9.0 t
- Total mass of drill collars **in mud**: d = 28 t
- Number of cable lines (strands): n = 8
- The **total work** transmitted by the **fast line** (the cable end that moves on the drawworks drum) during one complete maneuver is given by:

$$W_{total} = \frac{0.981}{n} \times \left[w_p \times L(L + l) + 4L(W_m + 0.5 \cdot d)\right] \times 10^{-6} \quad (10^3\mathrm{daN.km})$$

where w_p is the linear mass of drill pipes **in mud** (kg/m).

Questions:

1. Calculate the linear mass of drill pipes **in mud** (w_p) using the buoyancy factor.
2. Calculate the **total work** transmitted by the fast line (in 103103 daN·km) for one complete maneuver at L=1800 m.
3. If the drawworks motor can safely provide a maximum total work of 350×10^3daN·km per complete maneuver, what is the **maximum depth** $L_{\max}$ that can be reached (assuming all other parameters remain constant, and ignoring the change in drill collar mass with depth)?

Solution :

1. Linear mass in mud($\boldsymbol{w_p}$)

$$w_{air} = \frac{w_p}{f} \quad \text{(kg/m)}$$

Buoyancy factor $f \ = \ 1 \ - \frac{\rho_{mud}}{\rho_{steel}} = 1 - \frac{1.38}{7.85} = 0.824$

$$w_p = w_{air} \times f = 32.5 \times 0.824$$

$$w_p = 26.78 \, kg/m$$

2. Total work at L=1800m :

$$W_{total} = \frac{0.981}{n} \times \left[w_p \times L(L + l) + 4L(W_m + 0.5 \cdot d)\right] \times 10^{-6} \quad (10^3 \text{daN. km})$$

$$W_{total} = \frac{0.981}{8}[26.78 \times 1800 \times (1800 + 27) + 4 \times 1800 \times (9000 + 0.5 \times 28000)] \times 10^{-6} \quad (10^3 \text{daN. km})$$

$$W_{total} = 31.10 \quad (10^3 \text{daN. km})$$

3. Maximum depth for L :

$$W_{max} = 350 \quad (10^3 \text{daN. km})$$

$$350 = \frac{0.981}{8} \times \left[w_p \times L(L + l) + 4L(9000 + 0.5 \times 28000)\right] \times 10^{-6} \quad (10^3 \text{daN. km})$$

$$\mathbf{350\times\frac{8}{0.981}\times 10^{6}=[26.78\times L(L+27)+4L(23000)]}$$

$$\mathbf{2.854230377\times 10^{9}=26.78L^{2}+27L+92000L}$$

$$\mathbf{26.78L^{2}+92723.06L-2.854230377\times 10^{9}=0}$$

$$L=\frac{-b+\sqrt{b^{2}-4ac}}{2a}=8738m$$

Exercise 03 :

1 - Consider a block-and-tackle system with 10 lines. The load on the crown block in static conditions is equal to 192 tons. Calculate the tension in the 9th line.

Solution :

In static conditions ; n: number of lines

$$F=(2+n)t$$

$$t=\frac{F}{(2+n)}$$

$$t=\frac{192}{12}=16\ tons$$

$$t_1=t_2=t_3=\cdots\ldots\ldots\ldots.=t_9=t_{10}=16\ tons$$

2 - Consider an 8-line pulley system (mouflage),
P_r =908 hp, V=0.55 m/s, t_0=10 tons, k=0.98

The required lifting power is:

$$P_r=\frac{(t_{load}+t_0)\times 1000\times V_{load}}{75}$$

P_r :required lifting power (horsepower)

t_{load}: hook load (tons)

V_{load} :hoisting speed (m/s)

t_0 :weight of moving equipment (tons

$$t_{load} = \frac{kt_a(1-k^n)}{1-k}$$

$$t_a = \frac{(1-k)t_{load}}{k(1-k^n)} = 15.56 \text{ tons}$$

Tension in the 8th line:

$$t_8 = t_a \times k^8 = 15.56 \times 0.98^8 = 12.76 \text{ tons}$$

Exercise 04 :

1- Consider a block-and-tackle system with **n lines**.

The **tension in the 3rd line (in dynamic)** is **18 tons**.

The **load on the fixed block** is **165 tons**, and the **pulley efficiency** is k= 0.98.

Calculate the efficiency of the block system .

Solution :

Tension t_a : $t_i = t_a \times k^i$ $t_a = \frac{t_3}{k^3} = \frac{18}{0.98^3} = 19.2 \text{ tons}$

Find number of lines n: $F = t_a \frac{1-k^{(n+2)}}{1-k}$, $k^{n+2} = 1 - F\,(1-k)/t_a$

$$(n+2)\ln k = \ln(1 - F\,(1-k)/t_a)\ ,n = 7$$

$$n = 7 \Rightarrow \text{take 8 lines}$$

Efficiency of the system η :

$$\eta = \frac{k(1-k^n)}{n(1-k)} = 0.98$$

- ✕ Efficiency 0.98 → **physically impossible**
- ✔API value 0.841 → **correct and preferred**

Exercise 05 :

A drilling rig uses a block-and-tackle system of 8 lines .

The hook load is: $t_{load} = 140 \text{ tonnes}$, Weight of traveling equipment: $t_0 = 12\text{tonnes}$, Efficiency per sheave: k=0.98

The rope is EIPS steel with: R_m =1960MPa , Fill factor: K_f=0.60

Questions:

1. Calculate the active line tension t_a
2. Deduce the maximum tension in the rope (≈ fast line)
3. Estimate the minimum rope diameter d_c

Solution

Total load on the system : $\boldsymbol{t = t_{load} + t_0 = 140 + 12 = 152\,\text{tonnes}}$

Active line tension

Formula:

$$t = t_a \frac{(1 - k^n)}{1 - k} t = 152 = t_a \frac{(1 - 0.98^8)}{0.02}$$

$$t_a = \frac{152}{7.5} = 20.27 \text{ tons}$$

The **maximum tension = fast line tension**: $t_{max} = 20.27$ tons

Convert to Newton: $t_{max} = 20.27 \times 9.81 = 199$ kN

Choose safety. In drilling**:** $\boldsymbol{MBF \approx 5 \times T_{max} = 5 \times 199 = 995\text{kN}}$

Diameter calculation :

$$d_c = \sqrt{\frac{4 \times MBF \times K_f}{\pi \times R_m}}$$

$$d_c = \sqrt{\frac{4 \times (995 \times 10^3) \times 0.60}{\pi \times 1960}} = 19.7\, mm \approx 20\, mm$$

Chapter IV:
The Drawworks (Hoisting Winch)

IV.1 General Introduction : *(Also commonly referred to as the* ***drilling hoist*** *or* ***drilling winch****.)*

In oilfield drilling operations, the **drawworks** is the primary hoisting machinery on a drilling rig. It spools and unspools the drilling line to raise and lower the drill string, casing, and other downhole equipment.

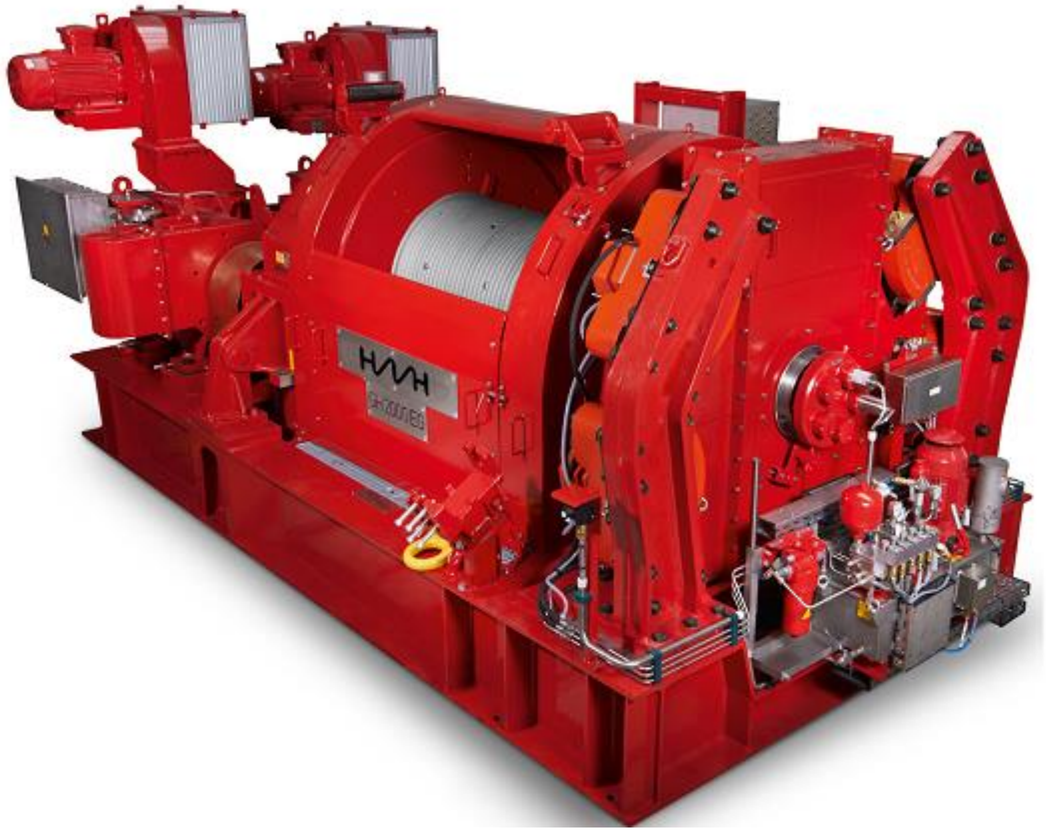


Figure IV.1: Drawworks.

IV.2 Motion transmission system:

The transmission system of the 840-E drawworks consists of several moving components:

IV.2.1 Shafts:

The 4 shafts of the drawworks are mounted on the structure with roller bearing assemblies:

- The **input shaft**, connected to the motors by a dual 3-strand chain, rotates at a constant speed of 602 rpm. An inertia brake mounted at the end of the shaft stops rotation during gear changes.

Figure IV.2 :Input shaft

The output shaft, connected to the input shaft by two 3-strand chains, has the following speed range: **HI:** 457 rpm and **LOW:** 285 rpm.

Figure IV.3 : Output shaft

The input shaft and the output shaft form the drawworks gearbox.

The drum shaft, connected to the gearbox by two 3-strand chains, transmits a rotational motion with 4 speeds:

Table IV.1: Input shaft

Speed (rpm)	Drum Clutch	Input Shuttle Shaft (Clabot)
LOW	65	243
HI	105	393

The cathead shaft (secondary shaft), connected to the drum shaft by a single-strand chain, has two rotational speeds: **LO:** 102 rpm, **HI:** 195 rpm

a.Chains and sprockets:

All chains transmitting power to the drum shaft are triple-strand chains with a 2-inch pitch (Figure IV.4). The drawworks chains are classified in a special category known as "Oil Field" chains. Indeed, the force due to centrifugal load, which is proportional to the square of the chain's linear speed, represents a significant portion of the total forces beyond a certain speed.

Table IV.2: Transmission Shaft Dimensions

Driving Shaft	Driven Shaft	Center Distance (in)	Pitch (in) / Strands	Z1	D1 (in)	Z2	D2 (in)	Lm
Motors	Input shaft	52.59	1.5" - 3 strands	28	13.39	51	24.36	110
Input shaft	Output shaft (HI)	23.93	2" - 3 strands	19	12.15	25	15.95	46
Input shaft	Output shaft (LO)	23.93	2" - 3 strands	20	12.78	42	26.76	56
Output shaft	Drum shaft (HI)	41.95	2" - 3 strands	37	23.58	43	27.39	82
Output shaft	Drum shaft (LO)	41.95	2" - 3 strands	19	12.15	83	52.85	98
Drum shaft	Secondary shaft	51.68	2" - 1 strand	39	24.85	21	13.41	82

Notes:

- **Lm** = number of chain links
- **Z** = number of teeth on sprockets
- **D** = pitch diameter (inches)
- All values are in inches

The design of a transmission is based on the load transmission by the chains and the rotational speed of the sprocket.

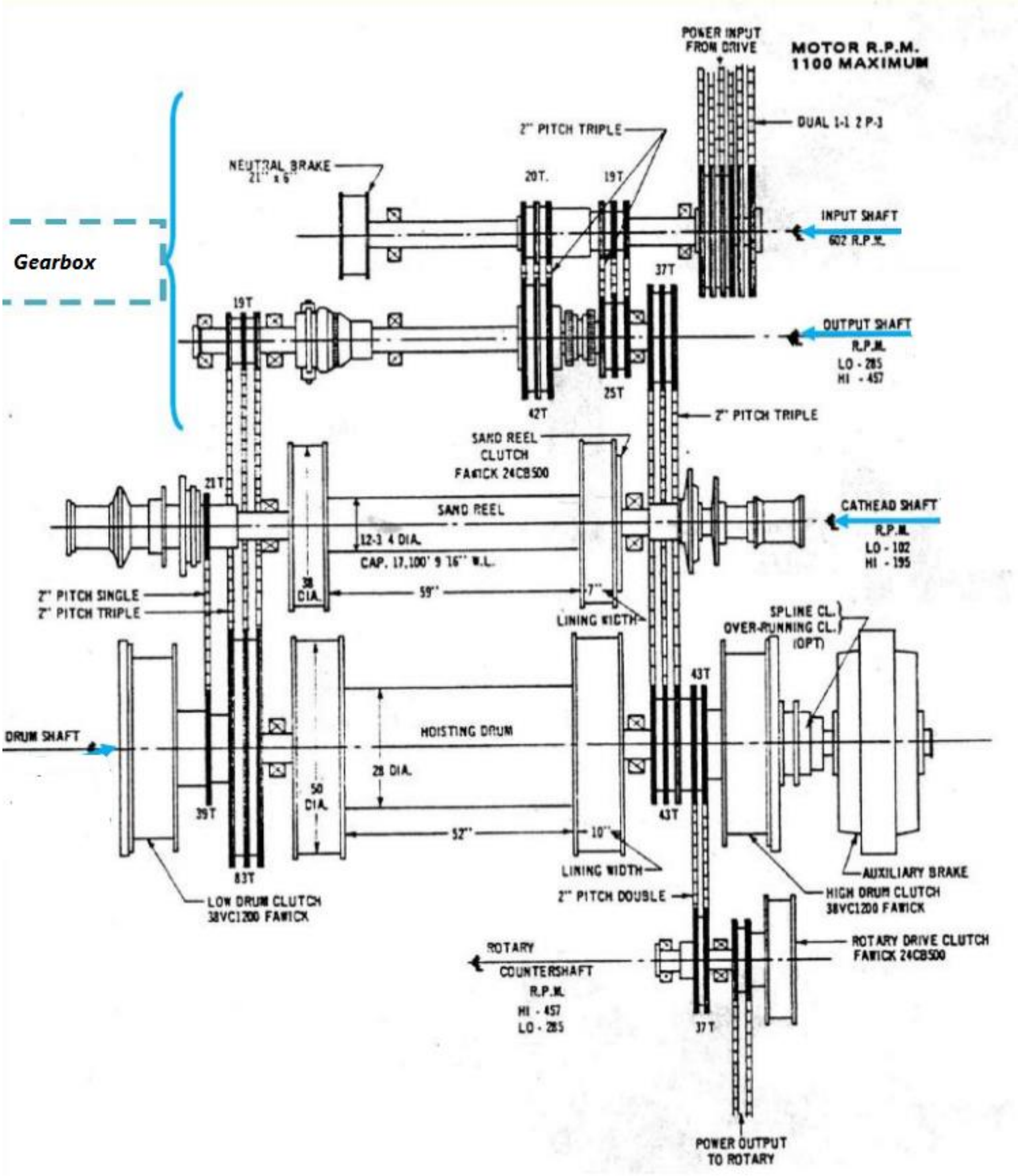


Figure IV.4 : Transmission Chains 840E Oil Well

Table IV.3 : Combined Technical Specifications of the 840E Drawworks

Parameter	Value
Number of speeds	4
Developed power	1400 HP (1029 kW)
Average well depth	3350 m to 4880 m
Main drum	
Drum dimensions (diameter × length)	28" × 52"
Flange dimensions (diameter × width)	50" × 10"
Lebus grooving	1 ½"
Clutch type	Friction
Dimensions and weight	
Width	15' – 6" 7/16 (4.73 m)
Length	22' – 8" (6.9 m)
Height	8' – 4" 7/8 (2.56 m)
Weight (excluding auxiliary brake, electric motors, shaft and cleaning drum)	20.41 tonnes

The drawworks (Figure IV.3 and Figure IV.4) is a component designed to ensure the suspension of the drill string during drilling operations and the suspension of the casing during cementing.

IV.3- Main Components of the Drawworks :

IV.3.1-Frame, skid, and housing :

The frame, skid, and housing must be rigid to avoid misalignment and improper alignment of the roller bearings.

- **Frame:** Typically fabricated from heavy welded steel I-beams or box sections. It supports the drum shaft, transmission shafts, and bearings.
- **Skid:** A base structure (often with lifting eyes or fork pockets) that allows the drawworks to be transported as a unit and bolted to the rig substructure. It ensures the drawworks remains aligned with the crown block and rotary table.
- **Housing:** Removable steel covers that enclose chains, sprockets, and gears. They protect personnel from moving parts, contain lubricating oil, and prevent dust/debris ingress. Some housings are designed to reduce noise.

Rigidity is crucial because:

- Any flexing under load changes the center-to-center distance of shafts, causing **chain tension variations** and **bearing overload**.

- The drawworks must maintain precise alignment with the **crown block** (via the drilling line) and the **rotary table** (via chain or cardan drive). Misalignment leads to rapid wear of chains, universal joints, and the drilling line itself.

IV.3.2-Operating drum : (figure IV.5)

The operating drum is the active part of the drawworks. The drilling line spools onto this element. There are two types of operating drums: **smooth** or **grooved**.

For proper spooling to prevent crushing of the line during suspension of heavy loads, the grooved drum shown below is strongly recommended.

- **Smooth drum:** Simple cylindrical surface. Only suitable for very light loads or temporary service because the wire rope tends to pile up, cross-wrap, and crush itself. Not recommended for main hoisting on modern rigs.

- **Grooved drum (often Lebus-type):** Helical grooves machined into the drum barrel. Each groove guides one wrap of rope. The pitch of the groove matches the rope diameter. Benefits include:
    - **Prevents crushing** – Grooves separate layers, reducing contact pressure.
    - **Eliminates overlapping** – Rope cannot jump across wraps.
    - **Extends rope life** – Lower wear and bending fatigue.
    - **Allows multi-layer spooling** – Essential for deep wells where thousands of meters of line are stored on the drum.

IV.3.3-Drum dimensions :

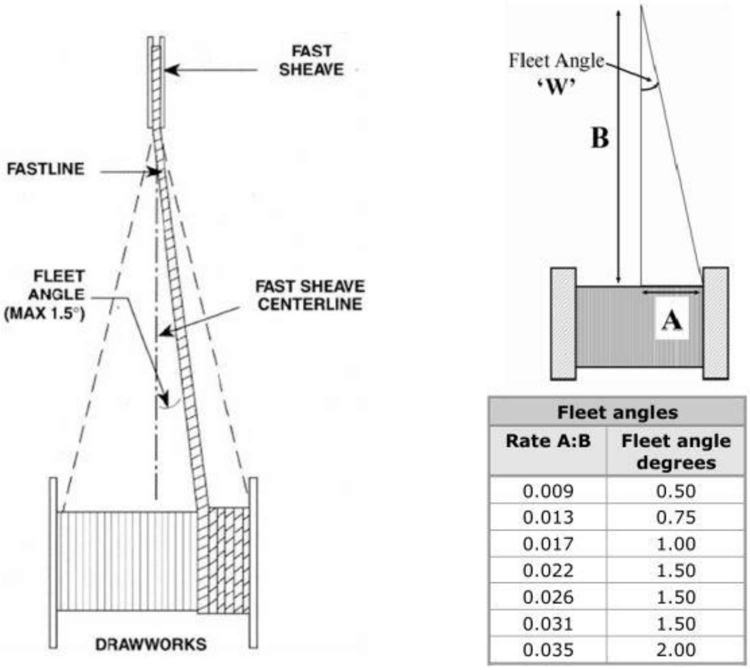
The drum diameter must be greater than or equal to 20 times the line diameter: $\mathbf{D \geq 20 \times d.}$ (D: drum diameter, d: line diameter)

- **Reason:** A small drum forces the wire rope to bend over a tight radius, causing high bending stresses that lead to **fatigue failure** of the steel wires. The 20:1 ratio is an industry rule-of-thumb (API RP 9B) to ensure acceptable rope life under typical hoisting loads.
- **Consequences of violation:** If $D < 20d$, the rope will experience premature wire breaks, reduced breaking strength, and increased crushing between wraps. The safe working load must be reduced.
- **Example:** For a 1-1/4" (31.75 mm) drilling line, minimum drum diameter = 20 × 1.25 = 25 inches (635 mm). Most drawworks drums are between 24 and 36 inches, so they meet or exceed this requirement.

Figure IV.5 : drum

IV.3.4- Deflection angle (Fleet Angle) :

The minimum length of the drum barrel is a function of the deflection angle of the active line, which must be between 1° and 1,5° (Figure IV.6). These values prevent premature cable wear due to friction and lateral bending.



Fleet angles	
Rate A:B	Fleet angle degrees
0.009	0.50
0.013	0.75
0.017	1.00
0.022	1.50
0.026	1.50
0.031	1.50
0.035	2.00

Figure IV.6 : Deflection Angle (Fleet Angle)

Formula for Deflection Angle (Fleet Angle)

$$tan(\theta) = \frac{Lateral\ offset\ from\ the\ center\ of\ the\ drum\ to\ the\ lead\ sheave}{Distance\ from\ the\ drum\ to\ the\ lead\ sheave\ (along\ the\ drum\ axis)}$$

$$\theta = arctan\left(\frac{A}{B}\right)$$

IV.4- Application Exercises : Drawworks Speeds

Exercise 01 :

The data of an Oil Well 840 E drawworks are (Figure IV.4):

- **Input shaft:** Z_{11} = 19 teeth, Z_{12} = 20 teeth
- **Output shaft (secondary):** Z_{21} = 25 teeth, Z_{22} = 42 teeth, Z_{24} = 37 teeth, Z_{25} = 19 teeth
- **Drum shaft:** Z_{31} = 43 teeth, Z_{32} = 83 teeth, Z_{33} = 43 teeth, Z_{34} = 39 teeth, Z_{35} = 43 teeth
- **Rotary table:** Z_4 = 37 teeth
- **Cathead shaft:** Z_5 = 21 teeth, high rotational speed N_cg = 195 rpm

Calculate the different rotational speeds.

Solution :

1. Drum

Low high speed:
$195\times Z_5/Z_{34}=195\times 21/39=105$ rpm

2. Secondary shaft (Output shaft)

High speed:
$105\times Z_{32}/Z_{25}=105\times 83/19=458$ rpm

3. Input shaft

Input speed $N_E=458\times Z_{21}/Z_{11}=458\times 25/19=602$ rpm (according to Figure IV.4)

4. Secondary shaft (Output shaft)

Low speed:
$N_{SL}=N_E\times Z_{12}/Z_{22}=602\times 20/42=286$ rpm

5. Drum

- **Low low speed:** $N_{SL} \times Z_{25}/Z_{32}=286\times19/83=65$ rpm
- **High low speed:** $286\times Z24/Z33=286\times37/43=246$ rpm
- **High high speed:** $458\times Z_{24}/Z_{33}=458\times37/43=394$ rpm

6. Cathead :

Low speed: $65\times Z_{34}/Z_5=65\times39/21=120$ rpm

7. Rotary table :

- **Low speed:** $246\times Z_{35}/Z_4=246\times43/37=286$ rpm
- **High speed:** $394\times Z_{35}/Z_4=394\times43/37=458$ rpm

Exercise 02 :

You have the data of the Oil Well 860 E drawworks according to the following diagram.

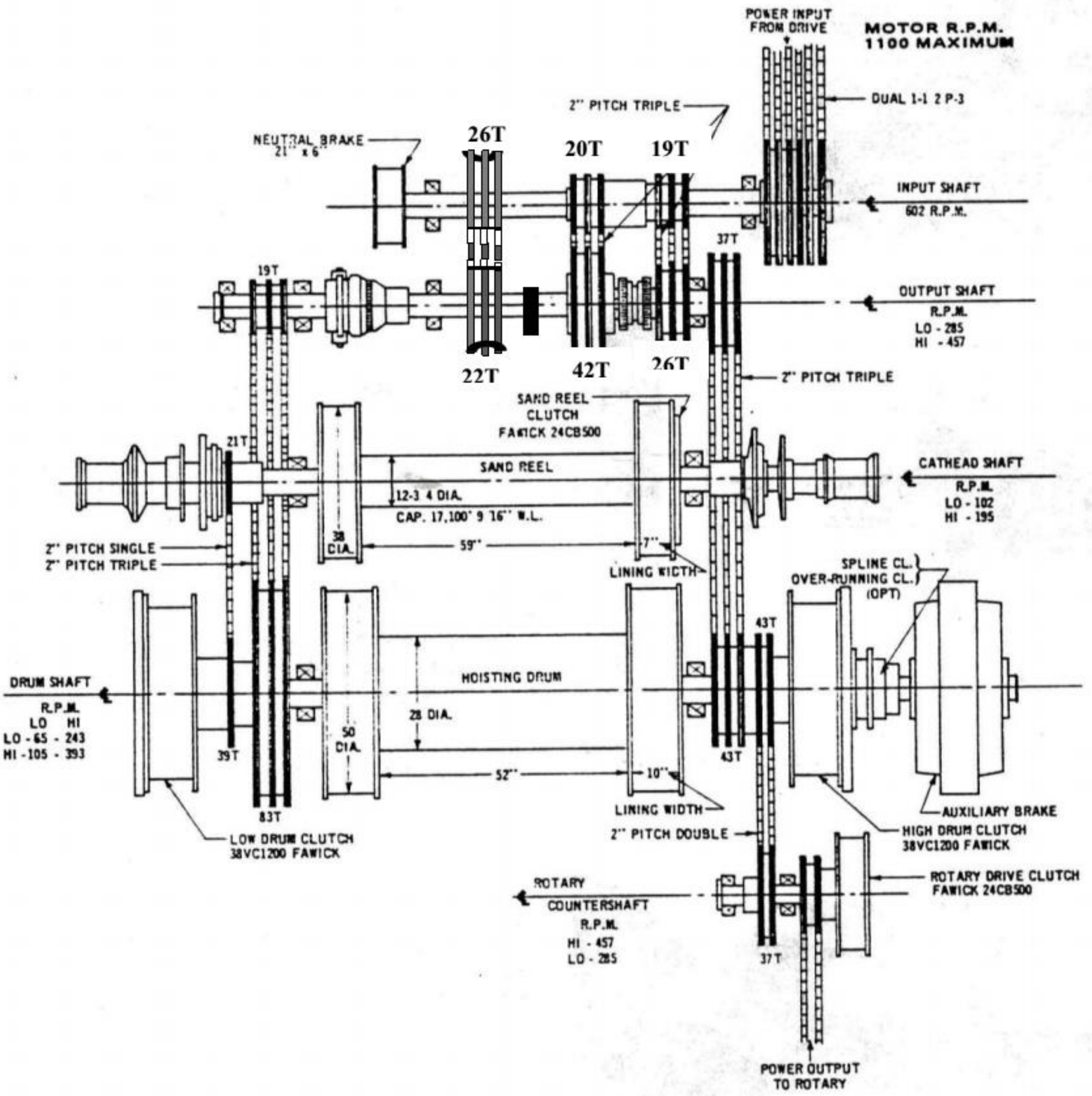


Figure IV.7: Kinematic chain of the 860E Oil Well Drawworks

Given: Cathead shaft: Z_5=21 teeth.
You are asked to calculate the different rotational speeds.

Solution :

1. Drum

High-high speed:

$466 \times Z_{24}/Z_{35}=466 \times 37/43=401$ rpm

2. Secondary shaft (Output shaft)

High speed:

$401\times Z_{35}/Z_{24}=401\times 43/37=466$ rpm

3. Input shaft :

Input speed $N_E=466\times Z_{23}/Z_{13}=466\times 22/26=395$ rpm (according to Figure IV.7)

4. Secondary shaft (Output shaft) :

- **Low speed:** $N_{SL}=N_E\times Z_{12}/Z_{22}=395\times 20/42=188$ rpm
- **Intermediate speed:** $NSL=NE\times Z_{12}/Z_{22}$, $395\times 19/25=300$ rpm (using different gears – probably Z_{11}/Z_{21})

5. Drum :

On the high side:

- **High-high speed** = 401 rpm (given)
- **High-low speed:** $188\times Z_{24}/Z_{33}=188\times 37/43=162$ rpm
- **High-intermediate speed:** $300\times Z24/Z33=300\times 37/43=258$ rpm

On the low side:

- **Low-high speed:** $466\times Z_{25}/Z_{32}=466\times 19/83=107$ rpm

- **Low-low speed:** $188\times Z_{25}/Z_{32}=188\times 19/83=43$ rpm

- **Low-intermediate speed:** $300\times Z_{25}/Z_{32}=300\times 19/83=69$ rpm

6. Rotary table

On the high side:

- **Low speed:** $162\times Z_{35}/Z_4=162\times 43/37=188$ rpm
- **Intermediate speed:** $258\times Z_{35}/Z_4=258\times 43/37=300$ rpm

7. Cathead : Using drum speeds (43, 69, 107 rpm) and $Z_{34}/Z_5=39/21$:

- **Low speed:** $43\times Z_{34}/Z_5=43\times 39/21\approx 80$)
- **High speed:** $107\times Z_{34}/Z_5=107\times 39/21\approx 199$ rpm
- **Intermediate speed:** $69\times Z_{34}/Z_5=69\times 39/21\approx 128$

Chapter V:
Rotary Drilling Materials & Circulation Systems

V.1-Rotary Drilling Materials :

In rotary drilling, the "rotation materials" refer to the set of mechanical components that work together to generate, transmit, and apply rotational motion to the drill string and bit. These materials are essential for breaking rock, deepening the wellbore, and maintaining control over the drilling process. The rotary system operates under extreme conditions: high torque (up to several tens of kN·m), heavy axial loads (the weight of the drill string can exceed 500 tons in deep wells), intense vibration, and contact with abrasive or corrosive drilling fluids.

The rotary system can be divided into two main categories:

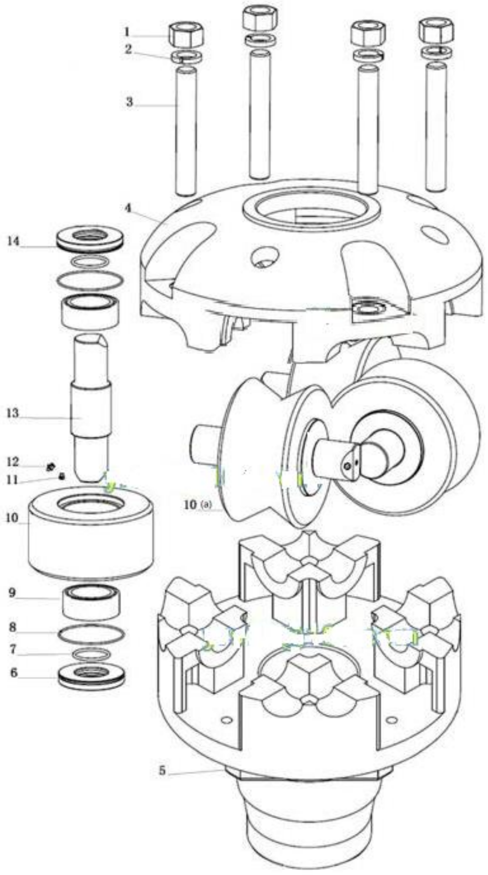
V.1.1- Surface Rotary Equipment :

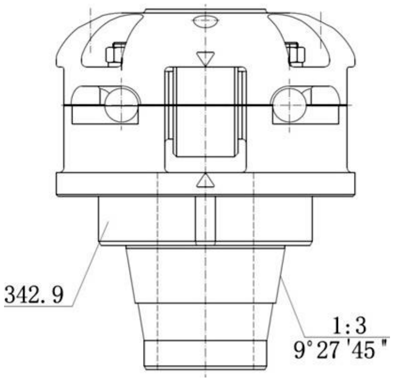
- **Rotary Table** – A heavy, powered mechanism mounted on the rig floor. It has a square or hexagonal opening that engages the kelly.
- **Kelly** – A long, four- or six-sided hollow steel bar that passes through the rotary table. It transfers rotation to the drill string while allowing vertical movement.
- **Swivel** – Suspended from the hook, it supports the kelly and drill string, allows rotation, and provides a high-pressure seal for mud circulation.

V.1.2-Downhole Rotary Components :

- **Drill String** – Made up of drill pipes, heavy-weight drill pipe, and drill collars. It transmits torque and weight from surface to the bit.
- **Drill Bit** – The cutting tool at the bottom. It grinds or shears rock using rotation and downward force.
- **Drill Collars** – Thick-walled steel pipes that add weight to the bit and keep the string in tension, reducing buckling.

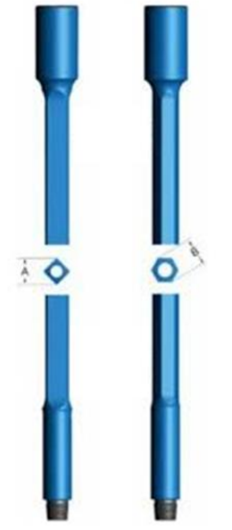
V.2-Rotating organs :



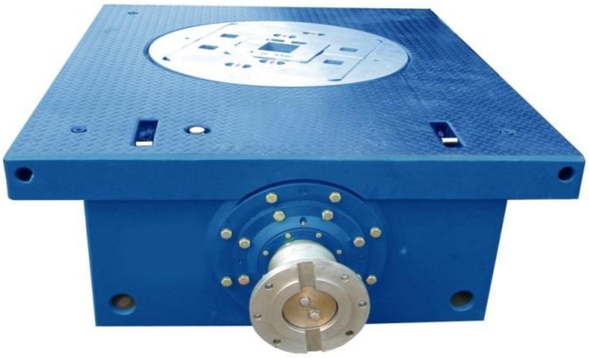


S.N.	Description	Qty
1	Hold down nut	4
2	Lock washer	4
3	Hold down bolt	4
4	Upper body half	1
5	Lower body half	1
6	Thrust washer	8
7	O-ring seal	8
8	O-ring	8
9	Sheave bearing	4
10	Flat roller	2
11-a	V- roller	2
11	Screw pin	4
12	Grease fitting	4
13	Roller pin	4
14	Pin	8

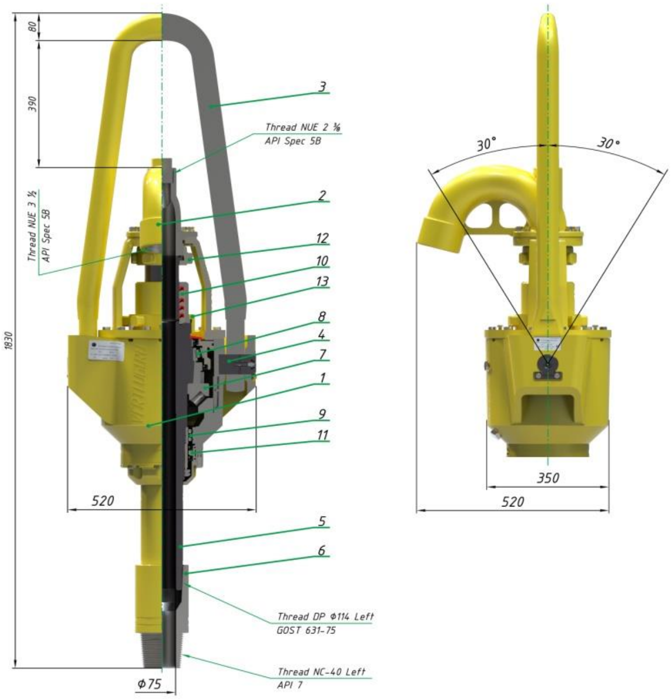
Roller Kelly Bushing

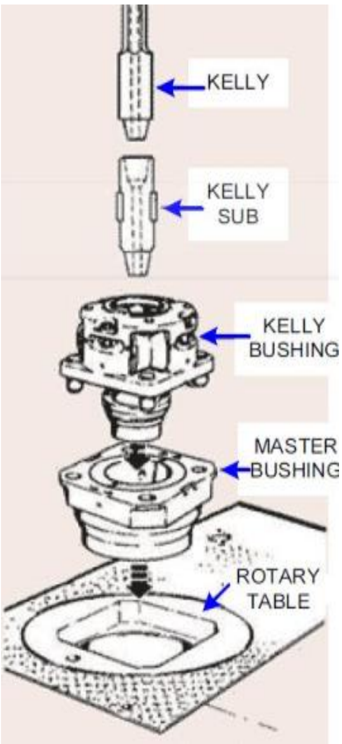


Square kelly Hexagonal kelly



Rotary table





swivel : the body 1 the gooseneck 2, a bail 3, installed in the lugs of the body 1 with the possibility of swinging on the fingers 4, a stem 5 with the sub 6 mounted on the bearings 7, 8 and 9 with rotation in the body 1, and the upper 10 and lower 11 seals.

Figure V.1 : The rotary components

The rotary components (Figure V.1) consist of:

- Rotary table
- Bushings
- Main bushings
- Kelly drive bushing
- Kelly saver sub
- Square or hexagonal kelly
- Swivel

The rotary components ensure the rotation of the drilling tool via the drill string.

The rotary table performs the following functions:

- **It transmits the rotational motion** to the drill string through the **drive bushing (kelly bushing)** and the **kelly (drive pipe)**.

- **During tripping operations**, it **supports the weight of the drill string** by means of the **slips (hold-down wedges)**

The rotary table is composed of:

- **The frame (base structure)**
- **The rotating part (rotary assembly)**
- **The drive shaft (input shaft)**

V.3-Characteristics of the Rotary Table :

V.3.1-Nominal Size :

The nominal size of a rotary table is defined by the maximum diameter of tools or casing that can be passed through the table opening. It is given by the inner diameter of the central opening of the rotary table (with the master bushing removed).

Table V.1 :Commonly used nominal diameters in drilling operations .

Nominal Diameter (inches)	**Common Application**
49½	Large-diameter drilling, surface casing
37½	Deep drilling, heavy casings
27½	Standard deep drilling
20½	Medium-depth drilling
17½	Common for intermediate drilling
12½	Slim-hole or workover operations

V.3.2-Standardized Center Distance : (Entraxe normalisé)

To ensure interchangeability between drawworks (hoists) and rotary tables, the distance between the center of the rotary table and the drive pinion (on the drawworks shaft) is standardized. This distance is called the **entraxe** (center-to-center distance).

Table V.2 : The standardized distances .

Rotary Table Size (nominal)	**Center Distance**
20½" and 27½"	**1.38 m** (54¼ inches)
17½" and 12½"	**1.22 m** (44 inches)

V.4-Rotary Table Drive and Speed Ratios :

V.4.1-Speed Ratio :

The transmission ratio between the drive pinion and the rotary table typically ranges from **3 to 4**, depending on the rotary table model and manufacturer. This ratio is defined as:

$$R = \frac{N_{table}}{N_{pinion}} \ or \ R = \frac{d_{gear}}{d_{pinion}}$$

Where:

- R : speed reduction ratio (dimensionless, typically 3.0–4.5)
- N_{pinion} : rotational speed of the drive pinion (rpm)
- N_{table} : rotational speed of the rotary table (rpm)
- d_{gear},d_{pinion} :pitch diameters of gear and pinion

V.4.2-Drive Mechanisms :

The rotary table can be driven using two main configurations:

1. Mechanical drive via drawworks

- **Cardan shaft (universal joint shaft)** : Transmits power from the drawworks output shaft to the rotary table pinion.
- **Chain drive** : Sprockets and roller chains provide flexible power transmission over longer distances.

Characteristics:

- Simple, robust, and widely used on older rigs
- The table rotates only when the drawworks is engaged
- Limited independent control

2. Independent electric motor drive (most common on modern rigs)

- A dedicated electric motor (AC or DC) drives the rotary table via a gearbox.
- **Advantage:** The table can rotate independently of the drawworks. The hoist can be stopped while rotation continues (essential for many drilling operations such as back reaming, making connections, or circulating while rotating).
- Allows precise speed control using variable frequency drives (VFDs).

V.5-Kelly Drive Bushing and Bushings :

The rotation of the rotary table is transmitted to the **kelly** (or to the drill string directly in top drive systems) via a set of bushings.
The torque transmission path is as follows:

Rotary table → Master bushing → Kelly drive bushing → Kelly → Drill string

V.5.1-Master Bushing (figure V.2) :

Figure V. 2 : Master Bushing

The master bushing features **four holes** on its upper face. The pins (or drive keys) of the kelly drive bushing engage into these holes. The torque transmission path is:

- Master bushing fits directly into the rotary table bowl (standard 4 inches per foot taper).

- It transmits rotation from the rotary table to the internal components (kelly drive bushing → kelly → drill string).
- Available in **solid (one-piece)** designs for smaller tables (20½″, 27½″) and **split (articulated / hinged)** designs for larger tables (37½″) to ease handling.

Table V.3 : Bushing Configurations by Table Size

Rotary Table Size	Bushing Type	Intermediate Bushing Needed	Internal Profile
20½″	One-piece	No	Square (direct)
27½″	One-piece + intermediate	Yes	Square / Hexagonal
37½″	Split (articulated) + intermediate	Yes	Square / Hexagonal

V.5.2-Intermediate Bushings (Adapter Bushings) :

Each master bushing must be used with a set of **intermediate bushings** (also called adapter bushings). Each intermediate bushing corresponds to a specific range of pipe or tool diameters. These bushings allow the same master bushing to accommodate different drill pipe sizes, casing, or tools without changing the entire rotary table assembly.

Figure V.3: Adapter Bushings

Function:

The intermediate bushing fills the annular space between the master bushing (fixed in the rotary table) and the kelly drive bushing or the slip assembly. It centralizes and supports the pipe or kelly while transmitting torque.

Specific Case: 27½″ Rotary Table

For a **27½″ table**, a set of intermediate bushings must be provided to accommodate the following diameter ranges (nominal pipe or tool outside diameters):

Table V.4 : nominal pipe or tool outside diameters

Range No.	Diameter Range (inches)	Typical Applications
1	2⅜″ – 8⅝″	Drill pipe (small to medium)
2	9⅝″ – 10¾″	Intermediate casing, HWDP
3	11¾″ – 13⅜″	Large drill collars, casing
4	16″ – 20″	Surface casing, large tools

Kelly Drive Bushing

- Sits inside the master bushing.
- Has a square or hexagonal central opening that matches the kelly's cross-section.
- Engages the flats of the kelly, providing positive torque transmission while allowing vertical sliding.

During rotation:

- The rotary table rotates the master bushing.
- The master bushing rotates the kelly drive bushing.
- The kelly drive bushing rotates the kelly (and thus the entire drill string).
- The kelly can move freely up and down inside the drive bushing as the well deepens.

V.6-The Kelly :

V.6.1-Definition and Role :

The kelly is the component that receives rotational motion from the rotary table (via the kelly drive bushing) and transmits it to the drill string. It slides vertically through the rotary table while rotating.

V.6.2-Geometric Characteristics

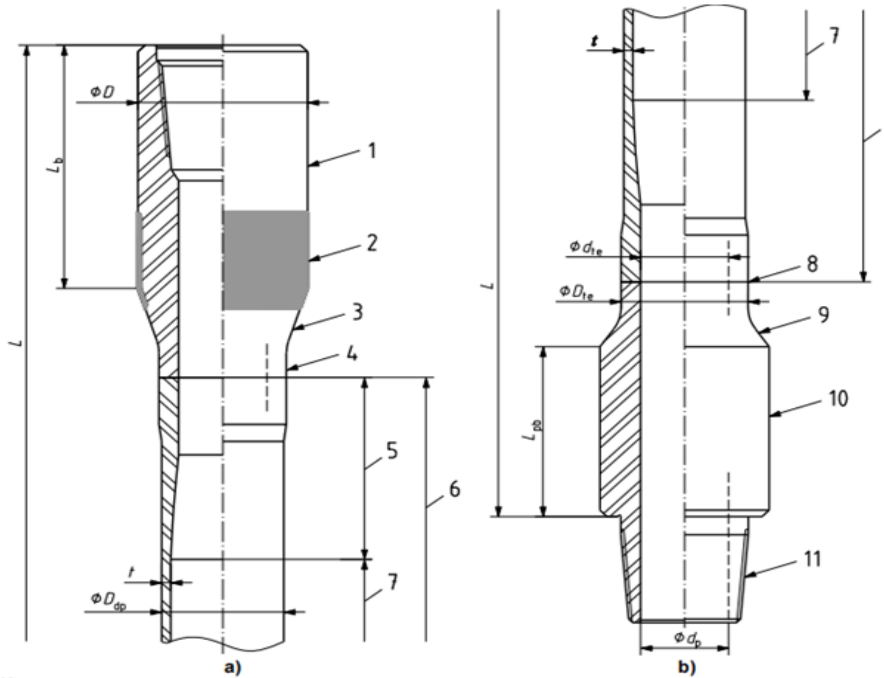
a. Usable Length

- The usable length corresponds to the profiled section (square or hexagonal) that passes through the rotary table.
- It must be long enough to drill a full **single joint** (one drill pipe length) before needing to add a new stand.

b. API Standard Total Length

- **Total length:** 12.19 m (40 ft)
- **Usable length (profiled):** 11.28 m (37 ft)

V.6.3- Connections and Threads :



Key

1	tool joint box	7	pipe body
2	hard banding (optional)	8	friction weld
3	tapered elevator shoulder	9	pin taper
4	drill pipe weld neck	10	tool joint pin
5	drill pipe body upset	11	rotary shouldered connection
6	drill pipe body		

Figure V.4: Connections and Threads

Upper Connection	**Lower Connection**
• **6⅝″ left-hand female thread (box)**	• **Right-hand male thread (pin)**
• Connects to the **swivel**	• Type: **Internal Flush (IF)**

V.6.4- Mechanical Characteristics :

a. Square vs. Hexagonal Kelly

- The **square kelly** has better mechanical characteristics than the hexagonal kelly (higher torsional stiffness and larger bearing surface).

b. Comparison with Drill Pipe

Mechanical characteristics of the kelly (square or hexagonal) are always **superior** to those of the highest API grade drill pipe (S-135).

- Example: minimum yield strength of a heat-treated 4145H steel kelly ≈ 150 ksi
- S-135 drill pipe: 135 ksi

V.6.5-Wear of Rotary Table and Bushings :

Causes : Repeated removal and reinstallation of bushings during tripping operations.

Consequences

- Wear of the rotary table interior and bushing surfaces (inner and outer).
- **Risks:**
  1. Crushing of tubular equipment
  2. Breakage of **slips**
  3. Slips settle lower in the bushing → they no longer support the pipe at the proper shoulder → reduced bearing surface area → increased risk of pipe slippage.

V.6.6- Kelly Saver Sub :

Purpose:

During pipe addition, the kelly is frequently made up and broken out from the drill string. This repeated threading wears the kelly’s internal threads.

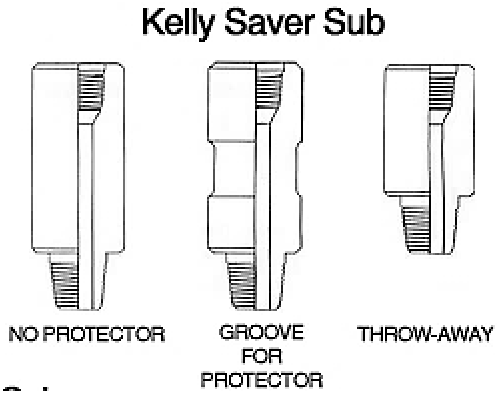


Figure V.5: Kelly Saver Sub

Function of lower saver sub:

- Installed between the kelly and the drill string.
- Absorbs wear from repeated connections.
- When worn, it is replaced – preserving the expensive kelly.

Upper saver sub (reducer/wear sub):

- Installed between the **fine thread** of the swivel and the **upper thread** of the kelly.
- Protects the swivel thread and adapts different thread types.

V.7– Circulation Function :

V.7.1Role of Circulation System Components :

The circulation system in drilling operations is designed to ensure several essential functions:

1. **Cuttings transport:** Provide an adequate annular velocity to prevent the settling (sedimentation) of drilled solids.
2. **Hydraulic pressure generation:** Deliver sufficient pump pressure to overcome all frictional and hydraulic losses within the circulation system.
3. **Suspension of cuttings during stops:** Maintain drilled solids in suspension when circulation is temporarily stopped.

4. **Bit cooling and lubrication:** Cool and lubricate the drill bit to improve drilling efficiency and extend tool life.

The **drilling mud pump** is the main component of the circulation system. It is a **reciprocating pump** that draws drilling fluid from the suction tanks and delivers it under pressure into the wellbore through the surface and downhole circulation system.

Drilling pumps must be capable of supplying an adequate flow rate during different drilling phases. This requirement depends on several operational parameters, including:

- Required cuttings transport velocity
- Maximum allowable cuttings return time
- Efficient hole cleaning and bit cleaning
- Wellbore stability
- Power transmission to downhole motors (if using mud motors)
- Flow regime in the annulus

Recommended maximum flow rates for different hole sections are:

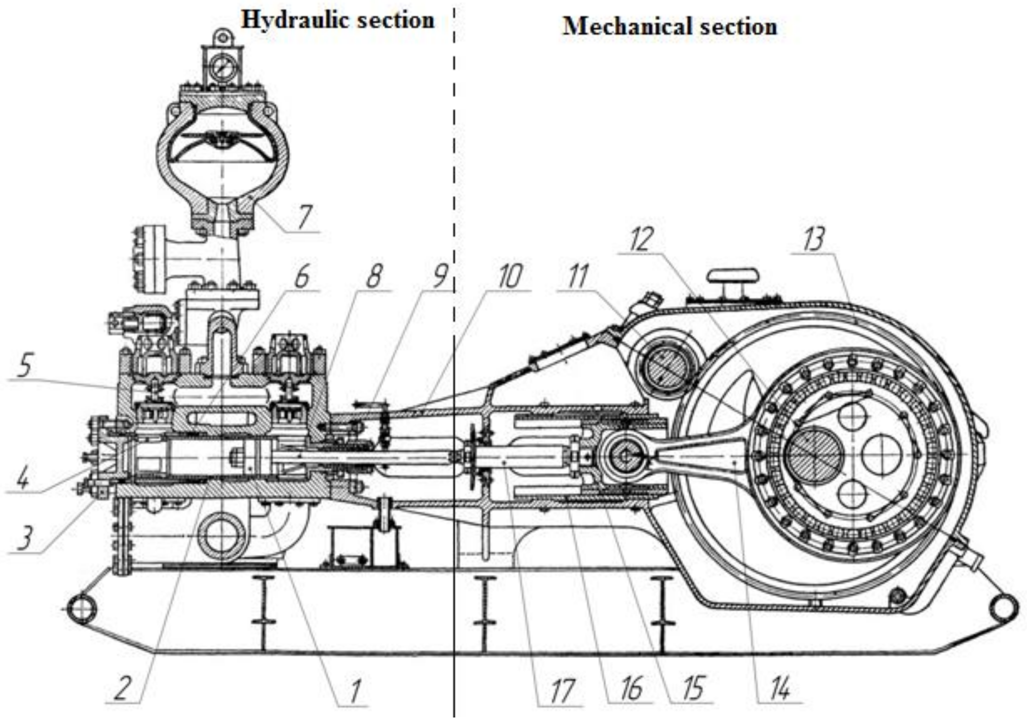
- 17"1/2 phase: **3500 L/min**
- 12"1/4 phase: **2500 L/min**
- 8"1/2 phase: **1500 L/min**
- 6"1/2 phase: **600 L/min**

V.8-Main Components of a Mud Pump :

A drilling mud pump (see Figure V.6) is generally composed of two main sections:

- **Mechanical section**
- **Hydraulic section**

The mechanical section provides the driving force (crankshaft, connecting rods, crosshead system), converting rotary motion into reciprocating motion.
The hydraulic section is responsible for fluid handling, including suction, compression, and discharge of the drilling fluid under high pressure into the circulation system.



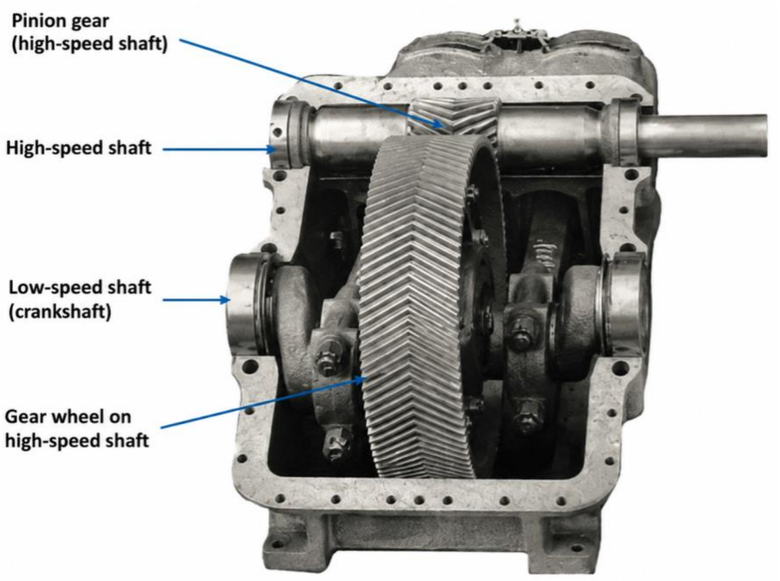
1 – Piston 2 – Cylindrical liner 3 – Cover 4 – Spacer 5 – Valve 6 – Cylinder liner sealing 7 – Pulsation dampener (air chamber / pneumatic compensator) 8 – Rod 9 – Rod sealing 10 – Frame (bed) 11 – Transmission shaft 12 – Main shaft 13 – Gear transmission 14 – Crank–connecting rod mechanism 15 – Crosshead (slider) 16 – Frame guides 17 – Counter rod

Figure V.6 : Double-acting duplex drilling mud pump

V.8.1-Mechanical Part :

The mechanical part of the pump converts rotational input into reciprocating motion to drive the pistons. It consists of the following components:

1. **Frame (Bed)** – [10] The main support structure housing the mechanical transmission and crank–connecting rod mechanism. It also serves as an oil sump and provides guideways for the crosshead.
2. **Transmission shaft** – [11] Receives power from the external drive (e.g., electric motor or engine).
3. **Gear transmission** – [13] A set of gears that reduces speed and increases torque from the transmission shaft to the main shaft.



FigureV.7 : Gearbox of duplex mud pump

4. **Main shaft** – [12] The output shaft of the gearbox that drives the crank–connecting rod mechanism.
5. **Crank–connecting rod mechanism** – [14] Converts the rotary motion of the main shaft into reciprocating motion. It includes the crank (integral to the shaft) and the connecting rod.
6. **Crosshead (slider)** – [15] Mounted within **frame guides** [16], it transforms the angular motion of the connecting rod into purely linear motion along the guides.
7. **Counter rod** – [17] A secondary rod (often used for balancing or connecting opposite pistons in a duplex configuration).

V.8.2- Hydraulic Part :

The hydraulic part of the pump is directly in contact with the drilling mud. It converts the mechanical reciprocating motion into hydraulic energy (pressure and flow) to circulate the mud. This section consists of the following components:

1. **Piston** – [1] The moving element that reciprocates inside the cylindrical liner, compressing and displacing the drilling mud.
2. **Cylindrical liner** – [2] A wear-resistant tube inside which the piston slides. It forms the chamber where the mud is pressurized.

Figure V.8 : Cylinder liner

3. **Cover** – [3] Seals the end of the cylinder and provides access for maintenance. It may also house valves or connections.
4. **Valve** – [5] Typically suction and discharge valves (ball or plate type) that control the direction of mud flow into and out of the cylinder a critical component for double-acting operation.

Figure V.9 : Valve

5. **Pulsation dampener (air chamber / pneumatic compensator)** – [7] Absorbs pressure spikes and reduces flow pulsations generated by the reciprocating pistons, ensuring smoother discharge.

V.8.3-Different types of pumps :

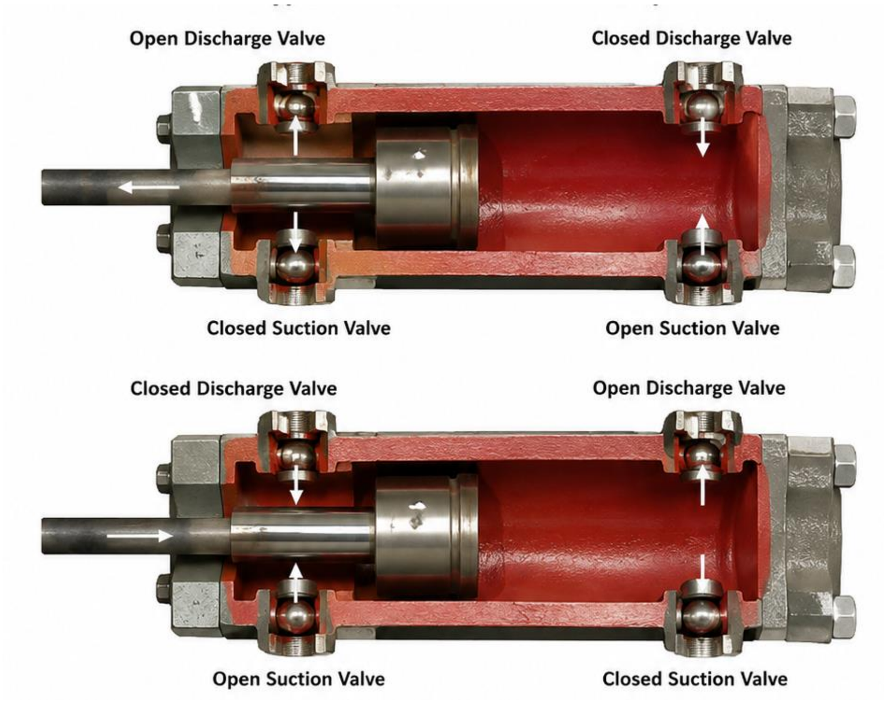


Figure V.10: Double-acting duplex pump (2 cylinders per pump)

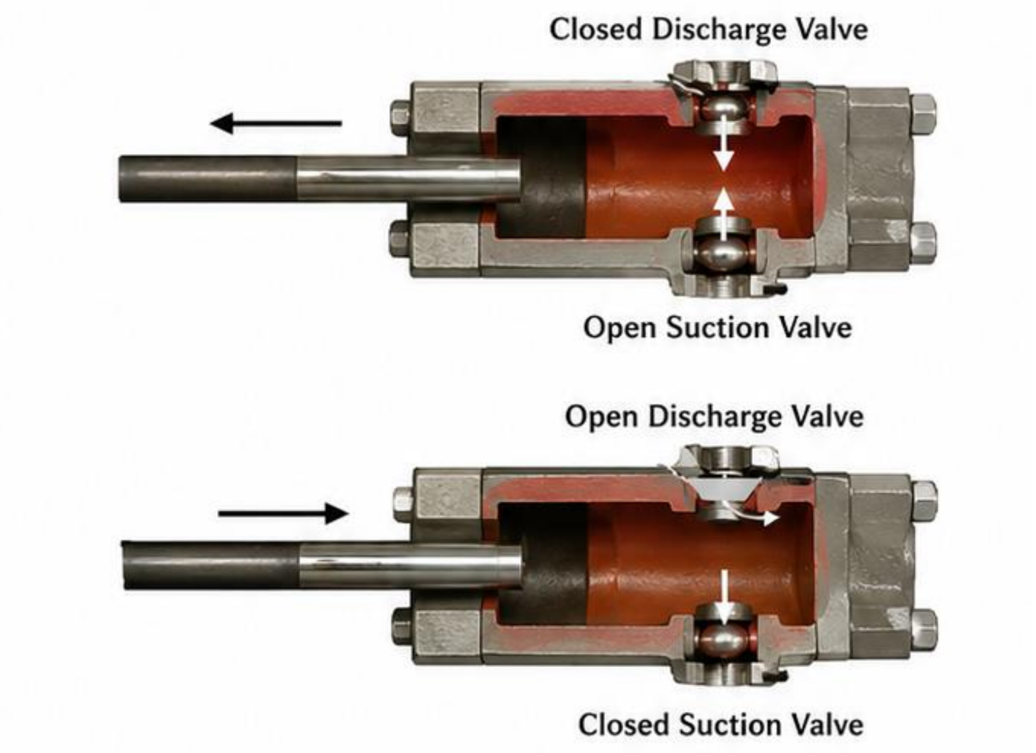


Figure V.11: Single-acting triplex pump (3 cylinders per pump)

V.9-Instantaneous flow rate variation (Figure V.12) :

Drilling pumps are reciprocating pumps.

In each cylinder, the piston starts with zero velocity, reaches maximum velocity at mid-stroke, and then returns to zero velocity at the end of the stroke. It then moves back following the same velocity profile.

The instantaneous flow rate per cylinder follows the same variation as the piston velocity.

However, depending on the pump type:

- For a **single-acting triplex pump** (3 cylinders), the return stroke flow rate is **zero** because only the forward stroke displaces fluid.
- For a **double-acting duplex pump** (2 cylinders), the return stroke flow rate is **smaller than the forward stroke flow rate** because the volume occupied by the piston rod is subtracted from the liner volume.

Theoretically, if the cylinder geometry and speed are identical, the forward stroke flow rate per cylinder is the same regardless of pump type.

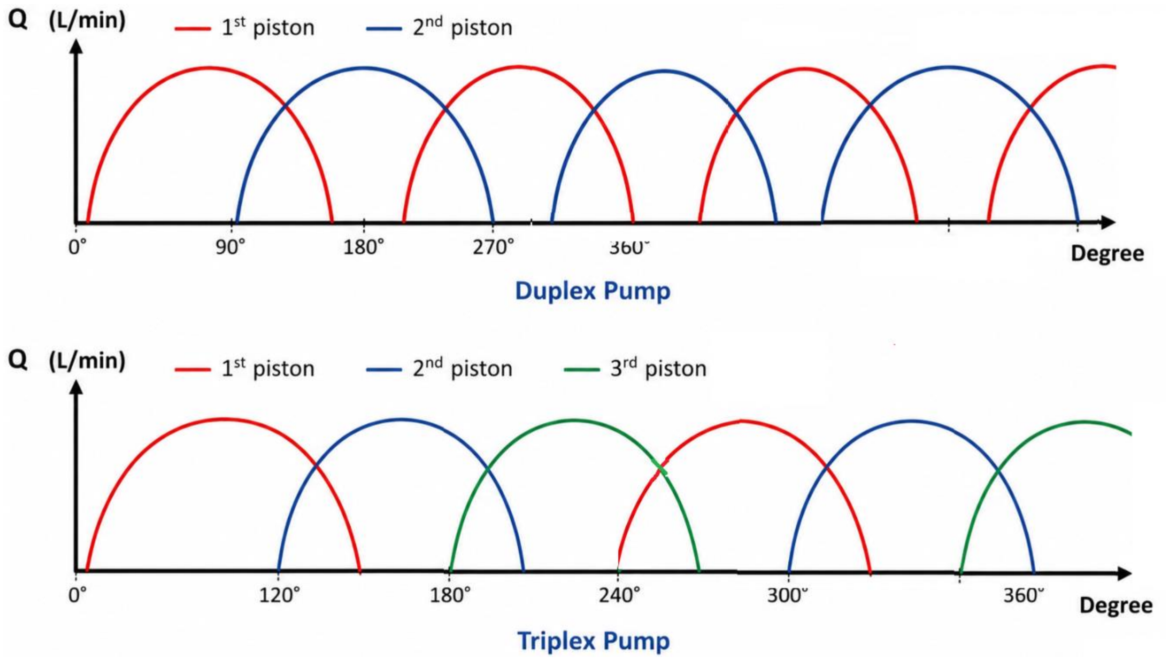


Figure V.12: Instantaneous flow rate variation**.**

Operating Parameters :

Mud pumps are characterized by the following parameters:

- **Mechanical or rated power**: (kW)
- **Stroke length**: (inches)
- **Liner diameter**: (inches)
- **Speed** (number of strokes per minute)
- **Maximum torque on the drive shaft**: (N·m)
- **Flow rates**: (liters/min)
- **Maximum pressures**: (kgf/cm² or psi)
- **Hydraulic power**: (kW, HP, or CV

V.10-Flow Rate and Power Calculations

a. Power

The maximum allowable mechanical power on the drive shaft (input shaft) is provided by the manufacturer for a given rated speed.

It is expressed by the relation:

$$P_m = C \cdot \omega \qquad \text{(V.1)}$$

Where:

- Pm : mechanical power (W or HP, depending on units)
- C : torque on the drive shaft (N·m)
- ω : rated angular speed (rad/s)

b. Flow Rate Calculation :

The flow rate of a reciprocating piston pump depends on the number of strokes, the stroke length, the piston and rod diameters, as well as the pump type (single-acting or double-acting, number of cylinders).

Table V.5 : Parameters used

Symbol	**Meaning**	**Unit**
Q	Flow rate	L/min
n	Number of double strokes per minute	strokes/min
L	Piston stroke length	inch (in)
D	Piston diameter	inch (in)
d	Piston rod diameter	inch (in)

Practical conversion: 1 inch = 25.4 mm; 1 L = 61,024 in^3 (approx.)

- **General formulas (per cylinder):**

For a single-acting pump (discharge only on the forward stroke):

$$Q_{1\,cyl} = 4\pi D^2 \cdot L \cdot n \qquad (\text{V}.2)$$

For a double-acting pump (discharge on both forward and return strokes, with the rod reducing the return volume):

- **Forward stroke volume:** $V_{forward} = \frac{\pi}{4} D^2 \cdot L \qquad (\text{V}.3)$
- **Return stroke volume:**$V_{\text{return}} = \frac{\pi}{4}(D^2 - d^2) \cdot L \qquad (\text{V}.4)$

Total volume displaced per double stroke (one forward + one return) is:

$$V_{\mathrm{STROKE}} = \frac{\pi}{4}(2D^2 - d^2) \cdot L \qquad \text{(V.5)}$$

The flow rate for a single-cylinder double-acting pump is:

$$Q_{1\ \mathrm{cyl,\ double-acting}} = \frac{\pi}{4}(2D^2 - d^2) \cdot L.n \qquad \text{(V.6)}$$

Total pump flow rate (all cylinders):

$$Q_{total} = m \cdot Q_{1\ cyl} \qquad \text{(V. 7)}$$

Where *m* is the number of cylinders (2 for duplex, 3 for triplex, etc.).

Example: For a **double-acting duplex pump** (2 cylinders):

$$Q_{total} = 2 \times \frac{\pi}{4}(2D^2 - d^2) \cdot L.n \qquad \text{(V. 8)}$$

For a **single-acting triplex pump** (3 cylinders):

$$Q_{total} = 3 \times \frac{\pi}{4} D^2 \cdot L.n \qquad \text{(V. 9)}$$

Unit conversion:

- If *L*,*D*,*d* are in **inches**, the volume obtained is in **cubic inches**.
- To obtain a flow rate in **L/min**, convert: 1 in^3=0.016387 L

Thus:

$$Q_{L/min} = Q_{in^3/min} \times 0.016387 \qquad \text{(V.10)}$$

Table V.6 : Flow rate formulas for double acting duplex and single acting triplex pumps

Pump type	Flow rate formula (L/min, inches, strokes/min)
Double-acting duplex (2 cylinders)	$Q_{total} = 0.0515\left(D^2 - \frac{d^2}{2}\right) \cdot L.n \quad (\text{V}.11)$
Single-acting triplex (3 cylinders)	$Q_{total} = 0.0386.D^2 \cdot L.n \quad (\text{V}.12)$

C – Maximum Service Pressure :

The maximum service pressure is calculated from the **maximum allowable force** on the piston rod extension:

$$P_{max} = \frac{F_{moy}}{A_m}\left(\frac{kgf}{cm^2}\right) \qquad (\text{V}.13)$$

Where:

- F_{max}maximum force (kgf) – constant for a given pump, independent of liner dimensions
- $A_m$average cross-sectional area subjected to the maximum pressure (cm²), depending on the liner size and pump type

The formulas for A_m are given below, with *D* and *d* in **inches**.

1. Double-acting duplex pump : $\boldsymbol{A_m = 5.06 \cdot \left(D^2 - \frac{d^2}{2}\right) \quad (cm^2)}$

2. Single-acting triplex pump : $\boldsymbol{A_m = 5.06 \cdot D^2 \qquad (cm^2)}$

Explanation:

Only the forward stroke area matters because the return stroke generates no flow. Converting $\frac{\pi}{4}$in^2 to cm² gives $\frac{\pi}{4} \times 6.4516 \approx 5.06$.

d – Hydraulic Power

Hydraulic power is calculated using the following formula:

$$P_H = \frac{P \cdot Q}{450} \qquad (CV) \qquad \text{(V.14)}$$

Where:

- P_H : hydraulic power in **CV** (metric horsepower)
- P = pressure in **kgf/cm²**
- Q = flow rate in **L/min**

Note: The constant 450 comes from the conversion factors: 1 **kgf/cm²** =0.9807 bar, and 1CV=735.5W.

The formula can also be expressed in kilowatts :

$$P_H\text{(kW)}= \frac{P \cdot Q}{600} \qquad \text{(with } P \text{ in bar, } Q \text{ in L/min).}$$

e – Volumetric Efficiency

Volumetric efficiency is defined as the ratio of the actual flow rate to the theoretical flow rate:

$$\eta_v = \frac{Q_r}{Q_t} \qquad \text{(V.15)}$$

Where:

- η_v = volumetric efficiency (dimensionless, often expressed as a percentage)
- Q_r = actual (real) flow rate in **L/min**
- Q_t = theoretical flow rate in **L/min** (calculated from piston displacement and stroke rate)

Importance of suction supercharging

Due to **leakage around the piston** (past the piston rings or seals), the actual flow rate is always less than the theoretical flow rate. To ensure proper filling of the cylinders and to avoid cavitation, it is **essential to supercharge the suction** using **centrifugal pumps** (i.e., a booster pump is placed upstream of the main pump).

V.11-Calculation of Pressure Losses in Oil Drilling Circuits :

Pressure losses in the circuits represent energy dissipation due to frictional forces during mud flow:

Internal fluid friction due to viscosity

External friction due to pipe wall roughness

Pressure loss is expressed as a pressure difference between two points in the pipe. The drilling mud starts with energy represented by the discharge pressure at the pump outlet and exits with zero pressure at the mechanical treatment equipment. Thus, the distribution of pressure losses in the drilling circuit is as follows:

- **Surface equipment pressure loss** (P_S)
- **Pressure loss inside drill pipes** (P_{DP})
- **Pressure loss inside drill collars** (P_{DC})
- **Pressure loss across bit nozzles** (P_{BN})
- **Pressure loss in the annulus** (P_A)

The **discharge pressure** is the sum of all pressure losses in the circulation circuit:

$$P_{dp}= P_S +P_{DP}+P_{DC}+P_{BN}+P_A \qquad \text{(V.16)}$$

Bottom hole pressure

Circulation stopped

Bottom hole pressure equals hydrostatic pressure:

$$P_b = P_H = \frac{d \cdot H}{10.2} \quad \text{(bars)} \qquad \text{(V.17)}$$

Where:

- d = mud density (kg/L or specific gravity)
- H = height (m)

During circulation (dynamic)

Bottom hole pressure is the sum of hydrostatic pressure and annular pressure loss:

$$P_b = P_H + P_A$$

The **equivalent circulating density** is given by:

$$d_{eq} = \frac{10.2 \cdot (P_H + P_A)}{H} \qquad \text{(V.18)}$$

Where:

- P_{dp}= discharge pressure (bars)
- P_b = bottom hole pressure (bars)
- P_H= hydrostatic pressure (bars)
- H = height (m)
- d_{eq} = equivalent density

V.11.1 **Pressure loss at the bit :**

Nozzle bits

The pressure loss at the bit is mainly caused by the acceleration of drilling fluid through the nozzles. It depends on the flow rate, the total nozzle area, and the mud density.

The pressure loss at the bit is given by:

$$P_{NB} = \frac{dQ^2}{2959.41.C^2A^2} \qquad \text{(V.19)}$$

Where:

- P_{NB}: pressure loss at the bit (kPa)
- Q: mud flow rate (L/min)
- d: mud density (kg/L)
- A: total nozzle area (in²)

Typical values of the coefficient C are:

- C=0.80 for non-jet bits
- C=0.95 for jet bits

Total Flow Area (TFA) or Nozzle Area (A_n)

For diamond and TSP bits, the total flow area (TFA) is defined by the manufacturer or selected by the operator according to the required hydraulic performance.

For PDC bits, roller cone bits, and TSP diamond bits, the drilling fluid flows from a high-pressure region inside the drill string to a low-pressure region at the bit exit through nozzles.

Nozzle bits

To control the drilling fluid flow rate and optimize hydraulics, PDC and roller cone bits are equipped with nozzles of different sizes. The total nozzle area is the sum of the areas of all individual nozzles, expressed in square inches (in²):

$$A_n = 0.000767(d_1^2 + d_2^2 + \cdots + d_n^2) \qquad \text{(V.20)}$$

Where:

- A_n: total nozzle area (TFA) in (in²)
- $d_1^2, d_2^2, \cdots, d_n^2$: nozzle diameters expressed in **1/32 of an inch**

Example: **A nozzle size of** 12/32 in **means: 12×1/32=0.375 in**

Table V.07 : Flow area (in²) as a function of nozzle size and number of nozzles

Dimension duse (in)	**Surface 1 duse**	**2 duses**	**3 duses**	**4 duses**	**5 duses**	**d buses**	**7 duses**
Nozzle size (1/32 in)	**Area 1 nozzle**	**2 nozzles**	**3 nozzles**	**4 nozzles**	**5 nozzles**	**6 nozzles**	**7 nozzles**
7/32	0.0376	0.0752	0.1127	0.1504	0.1880	0.2256	0.2632
8/32	0.0491	0.0982	0.1473	0.1964	0.2455	0.2946	0.3437
9/32	0.0621	0.1242	0.1864	0.2484	0.3105	0.3726	0.4347
10/32	0.0767	0.1534	0.2301	0.3068	0.3835	0.4602	0.5369
11/32	0.0928	0.1856	0.2784	0.3712	0.4640	0.5568	0.6496
12/32	0.1104	0.2209	0.3313	0.4416	0.5520	0.6624	0.7728
13/32	0.1296	0.2592	0.3889	0.5184	0.6480	0.7776	0.9072
14/32	0.1503	0.3007	0.4510	0.6012	0.7515	0.9018	1.0521
15/32	0.1726	0.3451	0.5177	0.6904	0.8630	1.0356	1.2082
16/32	0.1963	0.3927	0.5890	0.7852	0.9815	1.1778	1.3741
18/32	0.2485	0.4970	0.7455	0.9940	1.2425	1.4910	1.7395
20/32	0.3068	0.6136	0.9204	1.2272	1.5340	1.8408	2.1476
22/32	0.3712	0.7424	1.1137	1.4848	1.8560	2.2272	2.5984
24/32	0.4418	0.8836	1.3254	1.7672	2.2090	2.6508	3.0926
26/32	0.5185	1.0370	1.5555	2.0740	2.5925	3.1110	3.6295
28/32	0.6013	1.2026	1.8040	2.4052	3.0065	3.6078	4.2091
30/32	0.6903	1.3806	2.0709	2.7612	3.4515	4.1418	4.8321
32/32	0.7854	1.5708	2.3562	3.1416	3.9270	4.7124	5.4978

Nozzle velocity :

The nozzle (jet) velocity of the drilling fluid at the bit is an important hydraulic parameter that influences cleaning efficiency and cutting removal at the bottom hole. It is directly related to the flow rate and the total nozzle flow area.

The nozzle velocity is given by:

$$V = \frac{Q}{38.71 \cdot A} \qquad \text{(V.21)}$$

Where:

- V: nozzle velocity (m/s)
- Q: flow rate (L/min)
- A: total nozzle area (TFA) (in^2)

V.11.2 Hydraulic power and hydraulic intensity :

Hydraulic power

The hydraulic power represents the energy transmitted by the drilling fluid at the pump outlet. It is a key parameter in drilling hydraulics design and optimization.

The hydraulic power is given by: $P_h = \frac{P \cdot Q}{60000}$

Where:

- P_h: hydraulic power (kW)
- P: pump pressure (kPa)
- Q: flow rate (L/min)

Hydraulic horsepower intensity (HSI)

The hydraulic horsepower intensity (HSI) represents the hydraulic energy applied per unit area at the bottom hole. It is used to evaluate bit cleaning efficiency and hydraulic performance.

$$P_h HSI = \frac{P_{NB} \cdot Q}{35140 \cdot D^2} \qquad \text{(V.23)}$$

Where:

- P_h(HSI): hydraulic horsepower intensity (hp/in²)
- P_{NB}: bit pressure loss (kPa)
- Q: flow rate (gal/min)
- D: bit diameter (in)

V.11.3. – Pressure losses inside the drill string and in the annulus (continued) :

For a **Bingham fluid** in **turbulent flow**, the pressure loss equations take the following general forms depending on the geometry:

Table V.8 : Pressure loss formulas for Bingham fluid in turbulent flow: cylindrical pipe (inside drill string) and annular geometry

Section	Geometry	Pressure loss formula (turbulent flow)
a – Inside the drill string (drill pipes and drill collars)	Cylindrical pipe	$P = \frac{L \cdot d^{0.8} \cdot Q^{1.8} \cdot \mu_p^{0.2}}{KD^{4.8}}$
b – Annular space (between hole wall and drill string)	Annulus	$P = \frac{L \cdot d^{0.8} \cdot Q^{1.8} \cdot \mu_p^{0.2}}{K \cdot (D_0 + D_i)^{1.8} \cdot (D_0 + D_i)^3}$

Where:

- P = pressure loss (kPa or psi, depending on constant K)
- L = length of the section (m or ft)
- d = mud density (kg/L or specific gravity)
- Q = flow rate (L/min)
- μ_p = plastic viscosity (cP)
- D = internal diameter of drill pipe or collar (in)
- D_0 = outer diameter of the annulus (hole or casing inner diameter, in)
- Di = inner diameter of the annulus (outer diameter of drill pipe or collar, in)

- *K* = unit conversion constant **depends on geometry: Inside drill string (cylindrical pipe):** *K*=901.63,**Annular space:** *K*=706.96.

TableV.9 : Comparison: Duplex vs Triplex Reciprocating Pumps

Feature	**Duplex Pump**	**Triplex Pump**
Type of action	Double-acting	Single-acting
Number of cylinders	2	3
Size and weight	Large and heavy	Compact and lighter
Flow uniformity	Highly pulsating flow	More uniform flow
Volumetric efficiency	Lower	Higher
Pressure capability	Moderate	High to very high
Flow rate capability	High for its size (but less efficient)	High and more flexible
Mechanical balance	Poor (higher vibration)	Better balance (smoother operation)
Maintenance	More difficult and frequent	Easier and faster
Design complexity	Simpler mechanical design	More complex design
Cavitation sensitivity	Lower sensitivity	Higher sensitivity (requires good suction conditions)
Use in modern drilling	Rare / mostly obsolete	Standard in modern drilling rigs
Auxiliary equipment	Usually simpler system	Often requires charge (centrifugal) pump

V.12 Application Exercises – Pumps and Hydraulics :

Exercise 01 :

In an 8½" phase, we work with a double-acting duplex pump having the following characteristics:

P=150 bar, n=53 strokes/min, stroke L=10", liner size 6¾", rod diameter 3", mechanical efficiency η_m=0.8, chain efficiency η_{ch}=0.95.

Calculate the mechanical power at the output of the electric motors.

Solution :

The flow rate of a duplex pump is given by:

$Q = 0.0515\left(D^2 - \frac{d^2}{2}\right) \cdot L.n$ (L/min)

n: strokes/min, L: inches, D: inches, d: inches.

Q=0.0515×53×10×$(6.5^2 - \frac{3^2}{2})$ =1121 L/min

Hydraulic power:

$P_h = {}^{P \cdot Q}/_{450}$(CV) P in bar, Q in L/min P_h =150×1121/450 = 373.66 CV

Mechanical power at the electric motor output:

$P_m = P_h / \eta_m \cdot \eta_{ch}$ = 373.66/ 0.8×0.95= 491.66 CV

Exercise 02 :

In an 8½" phase, we work with a single-acting triplex pump having the following characteristics:

Actual flow rate Q_r =1064 L/min, flow losses represent 5%, P=150 bar, stroke L=12", liner size 7¼", mechanical efficiency η_m=0.8, chain efficiency η_{ch} =0.95.

Calculate:

- The flow rate per stroke V_T (L/stroke)
- The mechanical power at the electric motor output
- The mechanical power at the high-speed shaft input

Solution :

Actual flow rate = theoretical flow rate – 5% of theoretical flow rate = 0.95×0.95× theoretical flow rate.

Theoretical flow rate = actual / 0.95 = 1064/0.95=1120 L/min.

Hydraulic power:

$P_h = {}^{P \cdot Q}/_{450}$(CV) P in bar, Q in L/min P_h =150×1120/450 = 373.66 CV

Flow rate of a single-acting triplex pump:

$$Q = 0.0386. D^2 \cdot L. n \qquad (\mathrm{L/min})$$

n: strokes/min, L: inches, D: inches.

n =1120/(0.0386×12×7.252)=46 strokes/min

Flow rate per stroke:

$V_T = Q/n$=1120/46=23.35 L/stroke

Mechanical power at electric motor output:

$P_m = P_h / \eta_m \cdot \eta_{ch}$ = 373.33/0.8×0.95= 491.22 CV

Mechanical power at the high-speed shaft input:

373.33/0.8=466.66 CV

Exercise 03 :

In an 8½" phase, we use a nozzle bit and a mud density d=1.25. Data: Mud velocity at nozzle exit: V=130 m/s, Circulation rate: Q=1400 L/min

Calculate:

- Number of nozzles
- Nozzle diameter
- Hydraulic power at the bit face P_h*(HSI)*

Solution :

Nozzle velocity is given by:

$V = \frac{Q}{38.71\cdot A}$ *V* in m/s, *Q* in L/min, *A* = total nozzle area (TFA) in in^2.

$V = \frac{Q}{38.71\cdot A} = 1400/38.71 \times 130 = 0.2784$ in^2

From Table V.7 (flow area vs. nozzle size and number of nozzles) we deduce: Number of nozzles: 3 nozzles , Nozzle diameter: 11/32 in

Bit pressure loss: $P_{NB} = \frac{dQ^2}{2959.41.C^2A^2}$

P_{NB} in kPa, *d* in kg/L, *Q* in L/min, *A* in in^2, *C* = orifice coefficient: *C*=0.80 for non-jet bit, C=0.95 for jet bit.

The bit is jetted → C=0.95.

$$\mathrm{P_{NB}} = 1.25 \times 1400^2 \big/ 2959.41 \times 0.952 \times 0.27842 = 11835 \text{ kPa}$$

$$= 11835 \text{ kPa}$$

Hydraulic power at the bit face: $\mathrm{P_h HSI} = \frac{\mathrm{P_{NB}\cdot Q}}{\mathrm{35140\cdot D^2}}$

P_h(HSI) in HP/in^2, P_{NB} in kPa, Q in L/min, D = hole diameter (phase) in inches.

P_h(HSI)=11835×1400/35140×8.5^2 = 6.52 HP/in^2

Exercise 04 :

In a 12¼" phase, we use a PDC bit with 5 nozzles.

Given:

Mud density d=1.40

Cuttings rising velocity in the hole-pipe annulus = 40 m/min

Hydraulic power at the bit face = 4 HP/in²

Annular hole-pipe capacity = 62.7 L/m

1. Calculate the total nozzle area of the bit.
2. Calculate the bit pressure loss.

Solution :

Q = w×C 40×62.7=2508 L/min

$$\mathrm{P_{NB}} = \frac{\mathrm{dQ^2}}{\mathrm{2959.41.C^2A^2}}$$

$$P_h HSI = \frac{P_{NB} \cdot Q}{35140 \cdot D^2}$$

$$P_{NB} = \frac{P_h . 35140 \cdot D^2}{Q} = 4 \times 35140 \times (12.25)2\ /2508 = 8410\ \mathrm{kPa}$$

Then: $A^2 = \frac{dQ^2}{P_{NB} 2959.41.C^2} = 1.40 \times (2508)/22959.41 \times (0.95)^2 \times 8410$

A= 0.626 in^2

From Table V.7, the normalized area is 0.648 in².

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