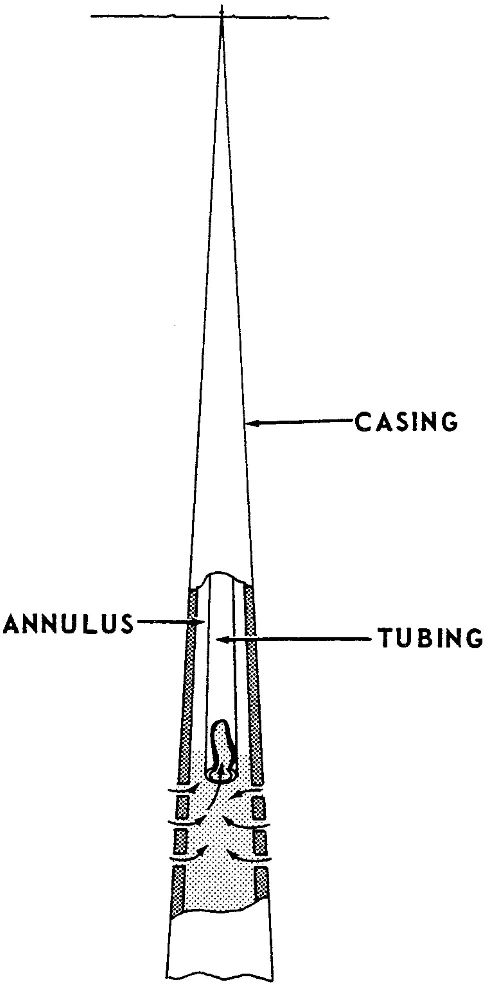
SUBSURFACE EQUIPMENT

Packers

142. In most wells, fluid is produced through the tubing.



Fluids also may rise up *around* the tubing, in the ____________.

143. At the well head, the annulus is (connected to/ closed off from) the tubing.

144. Flow from the annulus is controlled by a valve and outlet in the ____________ head.

145. Pressure in the annulus is registered on the ____________ pressure gage.

146. When the outlets in the tubing head are closed, fluid (flows/does not flow) through the annulus.

147. Any fluid entering the annulus is ____________ there.

148. Fluid trapped in the annulus may build up high pressure.

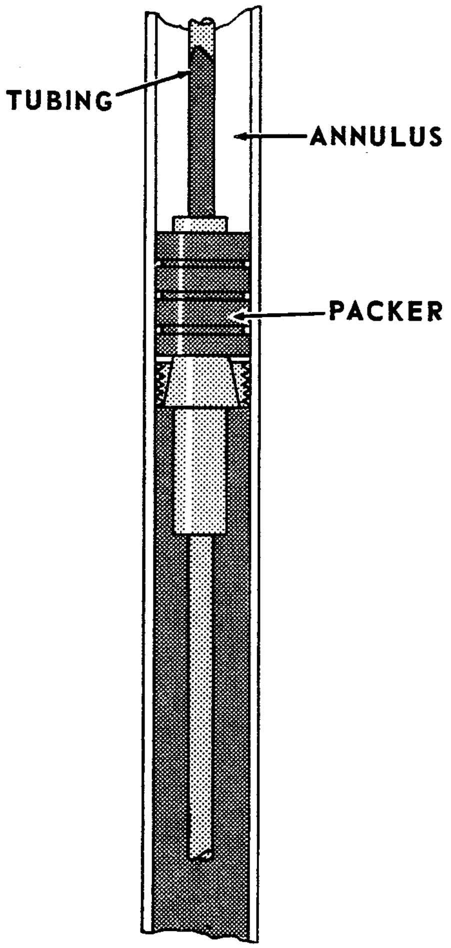
One reason for producing through tubing is to protect the ____________ from high pressure.

149. And some reservoir fluids are highly *corrosive.*

Corrosive fluids can ____________ away steel pipe.

150. When necessary, it is possible to replace damaged (tubing/casing).

151. A *packer* packs off the space between the tubing string and the production casing.



Packers prevent fluid from entering the ____________.

152. Packers also help support the tubing string from the bottom.

A packer can transfer some of the tubing weight to the bottom of the well-bore, or to the ____________ casing.

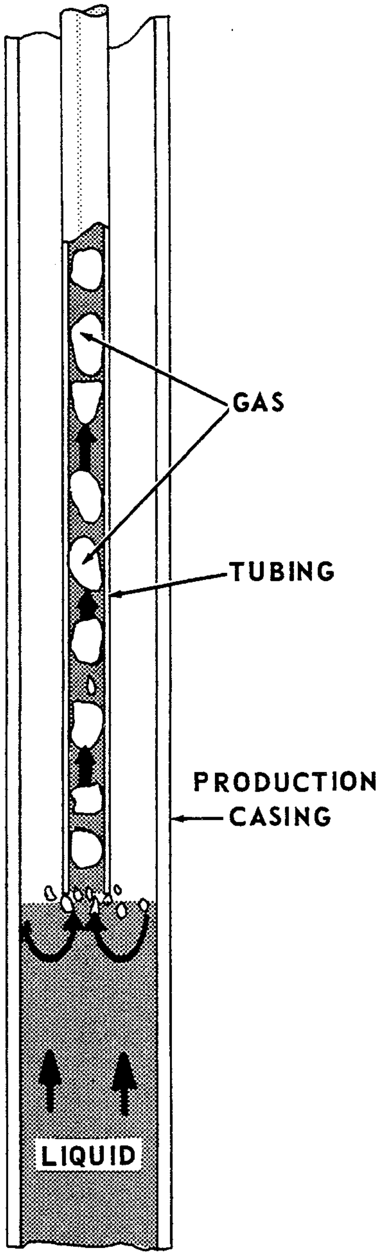
153. Many flowing wells are produced without a packer.

But use of packers prevents damage to the ____________ and prolongs the flowing ____________ of the well.

154. In some wells, bottom-hole pressure (BHP) is low enough to release gas from the fluid.

In a well without a packer, some of this gas is trapped in the ____________.

155. In an unpacked well-bore, casing pressures may get higher than tubing pressure.



Then the high-pressure gas from the annulus blows around into the ____________.

156. Blowaround gas causes heading, or intermittent flow.

Over-all production is higher when flow is (intermittent/continuous).

157. To prevent heading by blowaround, gas could be vented from the outlets in the (casing/tubing) head.

158. But venting off gas is a waste of formation ___________.

159. So, it is better to use a packer to prevent gas from entering the ___________.

160. Packers (cause/prevent) early heading in flowing wells.

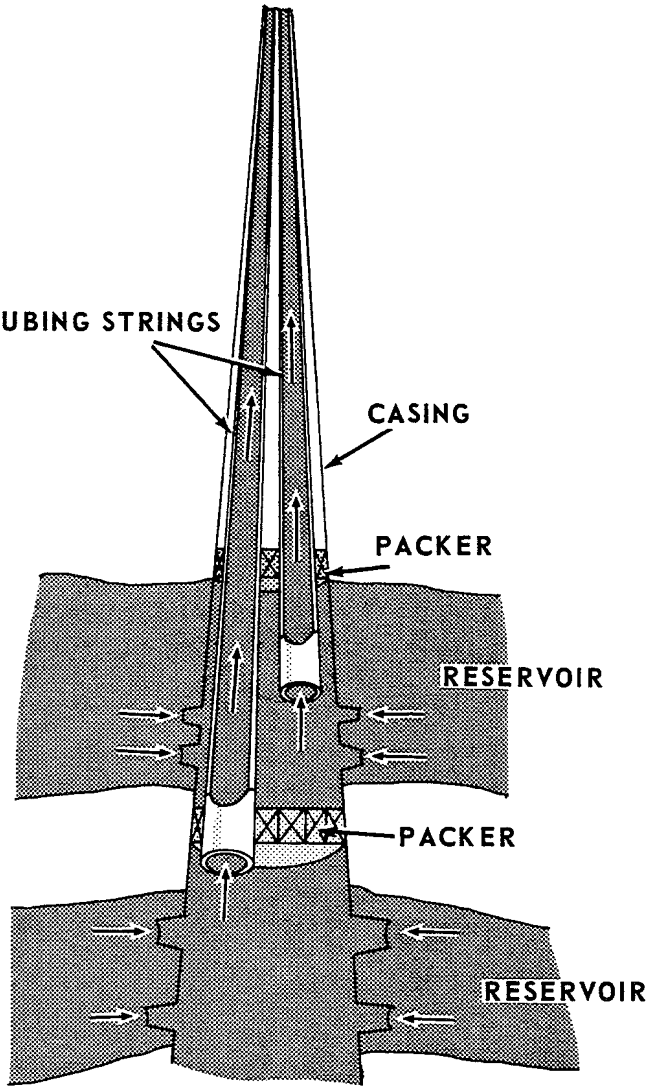
161. A *dual-completion* well may produce one reservoir through ___________ and the other reservoir through the ___________.

162. Suppose it is the lower reservoir that is being produced through tubing.

Then a ___________ around the tubing keeps flow from that reservoir out of the ___________.

163. Fluid from the upper reservoir may be produced directly through the annulus when there is a packer set (above/below) that reservoir depth.

164. Some dual completions are produced through two tubing strings.



Then fluid from the lower reservoir is directed into the ____________ by a packer.

165. And fluid from the upper reservoir is kept out of the annulus by a ____________.

166. In a multiple-completion well, there are generally as many packers as there are (producing formations/ tubing strings).

167. In a triple completion, where one reservoir is produced through the annulus, you would expect to find (one/two/three) packers.

168. Packers are installed:

to protect the ____________ from damage;

to prevent ____________ caused by blowaround gas;

to produce from more than one ____________ at the same time.

Bottom-Hole Chokes

169. A choke can be installed anywhere in the tubing or flow line of a well.

A choke installed at the well head is a (surface/subsurface) choke.

170. A choke installed in the tubing is a ____________ choke.

171. The pressure of the fluid entering the well head is lower when (surface/subsurface) chokes are used.

172. The main reason for using chokes is to control the ____________ of flow from a well.

173. But choking also increases the pressure (upstream/downstream) from the choke.

174. A choke which is very slightly smaller than the inside diameter (ID) of the tubing has very little effect on the fluid flow through it.

The choke must drop the pressure downstream to less than half of the pressure upstream before it can effectively ____________ the flow.

175. If the choke reduces pressure by more than half, back pressure is increased when a $\frac{1}{4}$" choke is replaced by a ($\frac{1}{8}$" / $\frac{1}{2}$") choke.

176. Back pressure results because fluid is leaving the upstream area (more rapidly/more slowly) than it would flow if there were no choke.

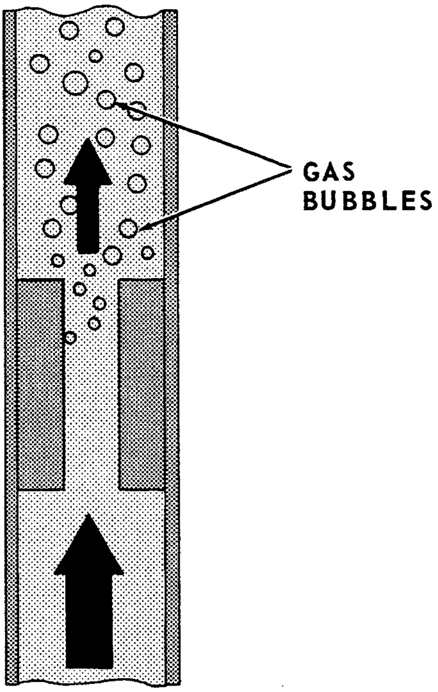
177. Or, choking:

decreases the ____________ ____________ from the well; and

increases or causes back ____________ upstream.

178. Since oil and gas tend to separate at lower pressures, choking tends to (cause/prevent) separation upstream.

179. Pressure is lower downstream from the choke.



The reduction in pressure often allows ____________ to expand downstream from the choke.

180. In the tubing, gas bubbles can help to lift the fluid.

Bubbles of gas released at a surface choke (help/do not help) to lift the fluid.

181. The gas released from the fluid at a choke deep in the well can be used to help ____________ the fluid to the surface.

182. The pressure drop at the choke affects the temperature of the fluid.

As the pressure drops, the lighter hydrocarbons in the oil change to gas.

This evaporation causes the temperature to (increase/decrease).

183. Both the pressure and the ____________ drop at a choke.

184. Fluids which flow clean at high temperatures may deposit solids in the choke, where temperatures ____________.

185. The deposition of solids may ____________ the choke.

186. Temperatures of the rock formations deep in the well are higher than surface temperatures.

Heat from the surrounding formations normally keeps a (surface/subsurface) choke from "freezing up" and becoming plugged with solids.

187. Or, subsurface chokes may be installed:

to (increase/decrease) surface pressures;

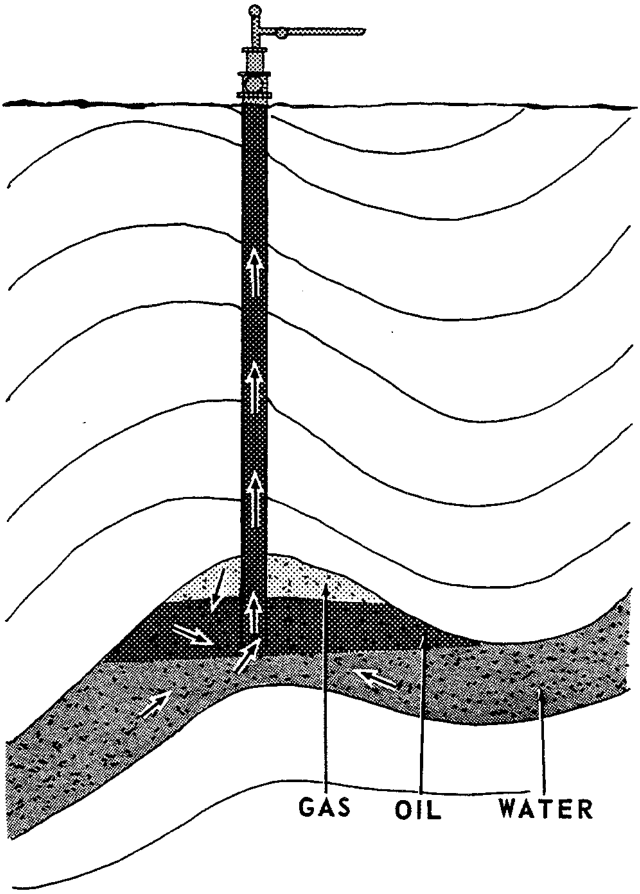
to release gas in the tubing, so that it can be used to ____________ the fluid;

to keep pressure drops deep in the well-bore, where temperatures are (high/low) enough to prevent solids from depositing out of the fluids.

188. Like surface chokes, subsurface chokes put back pressure on the reservoir.

Back pressure in the well-bore (increases/decreases) the flow rate from the reservoir.

189. The fluids in the reservoir may have settled in layers.



For optimum recovery, you want to draw fluid from (all three fluid layers/only the layer of oil).

190. The fluids leaving the reservoir will get mixed together more at (high/low) flow rates.

191. More gas and water will be produced along with the oil when the fluid is flowing at (higher/lower) rates.

192. Keeping back pressure on the reservoir (increases/decreases) the rate of flow from the reservoir.

193. Chokes (increase/decrease) the flow of gas and water from the reservoir.

194. Choking results in (more/less) efficient recovery and helps keep reservoir pressures (higher/lower).

195. Back pressure also (prevents/causes) gas break-out at the bottom of the well.

196. When there is no packer in the well, less gas enters the annulus if a choke (is/is not) used.

197. Gas that enters the tubing lifts more fluid when it is released deep in the well.

The gas that enters the tubing expands more and lifts more fluid when a (surface/subsurface) choke is used.

198. Subsurface chokes maintain a longer period of continuous flow and so (increase/decrease) the likelihood of early heading.

199. Since they seldom plug up with solid deposits, subsurface chokes do not often need to be changed.

Usually, the choke is changed to change the __________ of production.

200. Eventually, reservoir pressures decline and a (smaller/larger) choke must be installed to maintain the rate.

201. And, as more and more oil is produced, the volume of gas and water entering the well-bore will (increase/decrease).

202. The Gas-Oil Ratio will (rise/fall).

203. Water has a higher density than oil.

It takes a (higher/lower) pressure drop to move water than it takes to move oil.

204. The pressure *downstream* from a subsurface choke determines the pressure drop from the choke to the surface of the well.

This pressure drop is higher when the pressure downstream from the subsurface choke is (higher/lower).

205. To create a higher pressure drop from the subsurface choke to the surface, you must (increase/decrease) the orifice size.

206. When a well starts loading up with water, a (larger/ smaller) subsurface choke should be installed.

207. The effect of a subsurface choke on the GOR depends on well conditions.

With higher reservoir pressures, a subsurface choke reduces the GOR.

As reservoir pressures start to fall, the subsurface choke may increase the ____________.

208. Usually, well tests and recommendations by company technical personnel are used to decide when to use ____________ chokes to lower the GOR.

209. A *storm choke* is a subsurface safety valve.

A storm choke plugs the ____________ when conditions become unsafe.

210. Suppose there is a break in the surface lines of a flowing well.

Flow through the tubing will (increase/decrease).

211. Storm chokes close when flow rates get too high.

A break in the surface lines will shut in the well when a ____________ ____________ is installed in the tubing.

212. Some storm chokes have *annular sensing devices* which react to pressure in the annulus.

If the tubing string should begin leaking above a packer, casing pressure would ____________.

213. Storm chokes may be used to shut off flow through the ____________ when casing pressures rise.

214. This protects the ____________ from high-pressure or corrosive fluids, and also reduces damage to the ____________ string.

Review

215. Name this flowing well equipment.