# LECTURE №5-6-7
# PRESSURE MAINTENANCE
# BY GAS INJECTION

Pressure maintenance by injecting gas into the upstructure parts of the reservoir is most frequently used under conditions naturally favouring the development of a solution gas drive (low edge water activity, small difference in reservoir saturation pressure) and also when there is a natural gas cap.

Considering a pressure maintenance project with injection of gas into the upstructure part of the a reservoir, one must evaluate the practical and economic advantages of the project in each particular case. It must be borne in mind that reservoir pressure, particularly in the initial period of production, may be very high and costly equipment will be required to develop the high pressures that are necessary for a successful operation. It is also necessary to study carefully the geological conditions of the reservoir. For the success of the operation the structure not be too flat (the dip should preferably be not less than 12-15°); a low-dipping structure has an adverse effect on the gravitational separation of oil and gas.

It is desirable that the reservoir be uniform permeability and the oil of low viscosity. In nonhomogeneous reservoirs and in the presence of a large number of tectonic faults and fissures it is difficult to control the movement of the gas through the reservoir rock.

The best results are obtained when a pressure maintenance project is started early. However, field practice shows that gas injection can also be applied, though with less success, during later stages when a considerable quantity of gas has already evolved from the oil.

Gas injection wells should be located near crest of the reservoir. Natural oil gas is the best working agent, but if not available in necessary quantities, air can also be injected provided there is no gas cap. The injection of air into a gas cap is undersirable as it will considerably impair the quantity of the gas.

In designing the compressor stations it must be borne in mind that injection pressure is usually 15-20% higher than the formation pressure.

The quantity of gas to be injected into a well can be established experimentally by determining the injectivity index or it may be calculated approximately. In field practice, depending on the local conditions, 10000 to 25000 m3/day of gas are injected into wells at pressures from 5 to 9 MPa.

To prevent reservoir pressure decline, the quantity of gas injected should be not less than the total volume of fluid withdrawals.

In the majority cases, however, only the gas that is produced is recycled, and even not all of that because some is consumed to cover the field needs. If 70-80% of the gas produced is recycled, this is generally regarded as good pressure maintenance practice. Of course, this does not make up completely for the expended formational energy but nevertheless the process of pressure decline is much retarded.

Considering the high working pressure required for a gas-injection project, in order to save power the gas is supplied to the compressor from high-pressure gas-gathering lines and so-called *booster compressors* are used.

Gas injection is less effective economically than water injection because it is necessary to compress the gas to a pressure greater than the reservoir pressure. Not much of the power used in compressing the gas is compensated by its lower hydraulic resistance, as compared with water.

All schemes of location water injection wells can be used not only under injection water, but under  injection gas into oil deposit.

Pressure maintenance by injecting gas has not found wide use and is used mainly in depleted oil fields, where reservoir pressure is low.

The amount of gas needed for injection into the reservoir only for pressure maintenance at the current level will be equal to the sum of volumes of oil, water and gas under to formation conditions

$$V = V_{oil} + V_w + V_g,$$

where $V$ – amount of injected gas; $V_{oil}$ - oil withdrawal per day; $V_w$ - water production per day; $V_g$ – gas extraction per day.

The values $V_{oil}$ and $V_w$ determined by the actual data, taking into account the volume formation factors for the oil and water

$$V_{oil} = V_{oil0}\, b_{oil}; \quad V_w = V_{w0}\, b_w,$$

where $V_{oil0,}$ $V_{w0}$ – flow rate oil and water per day under standard conditions.

$V_g$ under formation pressure and temperature is defined by formula

$$V_g = \frac{\left[V_{g0} - \alpha\left(P_f - P_0\right)V_{oil0}\right]P_0 z T_f}{P_f T_0},$$

where $V_{g0}$ - gas extraction per day under standard conditions; $\alpha$ - gas solubility coefficient; $P_f$ - formation pressure; $P_0$ - pressure under standard conditions; $z$ - gas compressibility factor under formation pressure and formation temperature; $T_f$ - formation temperature; $T_0$ - temperature under standard conditions.

Gas injection in wells through tubing that is lowered to the top of the filter column. Annular space between the tubing and casing packer block, which is set at the lower end of the tubing. The aim is to isolate the column, which is not always withstand high injection pressures, and the depleted fields casing is leaking due to corrosion.