TOMSK POLYTECHNIC UNIVERSITY

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ANALYSIS OF HYDROCARBON SYSTEMS In DETERMINING THEIR QUALITATIVE CHARACTERISTICS In PIPELINES

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This course book includes the following issues: physico-chemical and technological features of oil and gas connected with such problems as fluid and gas regimes, quality measurement and different hydrocarbon flow rates. Classification and control -measurement devices in calculating hydrocarbon quantity are described. Hydrocarbon flow measurement technology applied in oil and gas units are depicted.

It is appropriate for students of the Geology & Petroleum Engineering Institute; specialty- 130501 «Design, construction and operation of oil pipelines and oil tank storage»

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CONTENTS

PREFACE

Fluid and gaseous hydrocarbon sources and its refining products are the main economic constituents. Every enterprise or industry is directly or indirectly is connected with oil, gas and oil product distribution. Hydrocarbon sources are not only energy sources, but also the base for sophisticated technology development, modern material and product production. Further development of the country's economy is inseparably linked with the hydrocarbon source recovery increase. Such regions as Timano-Pechorsk and East-Siberia regions include new oil fields which in 2020 could provide oil and gas condensate recovery of up to 360 bil. tonne/ year, gas 700 bil. m^3/year. These factors lead to such issues as transportation, storage, control and measurement of oil and gas products and their refining.

Pipeline transportation indicates high economic and reliability factors. Total crude trunk pipeline length is 219 thous. km., including gas pipelines-150 thous. km, oil pipelines - 49 thous. km, oil product pipelines-20 thous. km. Transportation can be carried out by sea or railway in the absence of pipeline network.

There are different storage methods. Fluid hydrocarbons (oil, oil products, and associated gas) are stored in various designed tanks, included in the pipeline system, gathering system or distribution centers (pumping stations, tank farms, etc.). For natural gas storage special underground facilities are used – underground gas tanks where gas is pumped under pressure for long-term storage and further pumping in case of season consumer level changes.

Due to different transportation and storage methods, there are problems in choosing the optimal quality and qualitative measurement units and methods. However, there is no uniform approach to the development of measurement units because of the different characteristic features – physico-mechnical hydrocarbon characteristics and their dependence on external factors (temperature, pressure, etc.). These issues can be only solved by considering all factors influencing the fluid and gas hydrocarbon properties and applying sophisticated methods and measurement devices.

This course book describes the major methods in determining hydrocarbon quantity, those characteristics affecting accurate measurement, primary and secondary measurement devices and systems; as well as, the main development trends in measurement methods and device production. The main objective of the following course book is to give a complete integrated understanding of the complex problems in quantity measurement of fluid and gas hydrocarbons.

1. GENERAL PROPERTIES OF HYDROCARBONS

Crude oil is a flammable, viscous liquid, primarily of dark colour. It comprises a complex mixture of hydrocarbons of the following groups: methane (paraffin) - C_nH_{2n+2} (alkanes)*; naphthene - C_nH_{2ni} (alkynes)*; aromatic - C_nH_{2n-6} (arenes)*. The major methane –group (methane CH_4; ethane C_2H_6; propane C_3H_8; butane C_4H_{10}) is in a gaseous state at atmospheric pressure and normal temperature. Pentane C_5H_{12}, hexane C_6H_{14} and heptane C_7H_{16} are unstable, as they pass easily from gaseous to liquid state and visa versa. Hydrocarbons with their variations from C_8H_{18} to $C_{17}H_{36}$ are liquids. Hydrocarbons with more than 17 carbon atoms are solids (paraffin). An "average" crude oil contains about 82-87% carbon, 11-14% hydrogen, oxygen, nitrogen, sulfur, carbonic acid and less of chlorine, iodine, phosphorus, arsenic and other metals and salts.

Natural gas composition:

- *hydrocarbons (alkanes C_nH_{2n+2} and cyclones C_nH_{2n});*
- *non-hydrocarbons (N_2CO_2, H_2S, mercury, sour RSH);*
- *inert gases – helium, argon, krypton, xenon.*

Phase state: methane (CH_4), ethane (C_2H_6), ethyne (C_2H_4) at normal conditions (p= 0.1MPa and t= 273 K) are real gases and comprise net gas.

Propane (C_2H_6), propylene (C_3H_6), isobutene (i= C_4H_{10}), normal butane (n= C_4H_{10}), butylenes (C_4H_8) at atmospheric conditions are in vaporous (gaseous) state, at increased pressure – in liquid state. They comprise fluid (petroleum \ liquefied) hydrocarbons.

Hydrocarbons from isopentane (i= C_5H_{12}) and to heavier ones (17 > n > 5) at atmospheric conditions are in liquid state. They comprise the petrol fraction.

Hydrocarbons with 18 or more carbon atoms (from $C_{18}H_{28}$) in one chain at atmospheric conditions are in solid state.

Physical and chemical properties *determine the commercial (economical) quality of hydrocarbons during transportation and storage.*

One of the main indexes of commercial (economical) hydrocarbon quality is density ρ (absolute relationship between mass and volume). The less dense the oil is – the lighter the oil, and the more valuable it is.

Density *– is the mass of a given volume, i.e. ratio of the mass is quiescent to the volume.*

The SI unit is kg\ m^3. Density is measured by an aerometer. Aerometer is a device to determine the density of a liquid by sinking a float to different depths (a tube with points and a float at the bottom). The aerometer points indicate the density of investigated crude oil.

Density of crude oil is an important operational characteristic. The less oil can be converted into oil with the lighter molecules. Crude oil density is classified as absolute and relative. Absolute density – is the ratio of a fluid mass to a volume unit.

For example, density of benzene – 730 - 760 kg\ m^3; kerosene - 780 - 830 kg\ m^3; diesel fuel - 840 - 850 kg\ m^3; crude oil - 800 - 940 kg\ m^3 (Table 1.1).

* according to IUPAC nomenclature of organic chemistry

Table 1.1.

Density and volumetric expansion coefficient

Crude oil density kg\ m3	ξ10 \ C	Crude oil density kg\ m3	ξ10 \ C
800 - 819	0.000937	920 - 939	0.000650
820 - 839	0.000882	940 - 959	0.000607
840 - 859	0.000831	960 - 979	0.000568
860 - 879	0.000782	980 - 999	0.000527
880 - 899	0.000738	1000 - 1200	0.000490
900 - 919	0.000693	-	-

Relative density (dimensionless value) is a ratio of absolute density of investigated medium to the volume of a standard substance (for example, water).

Crude oil density varies according to pressure and temperature changes. Therefore, density is a function that depends on temperature and pressure

$$\rho(T) = \rho_{20}(1+\xi(20-T)), \qquad (1.1)$$

where $\boldsymbol{\rho_{20}}$ *– crude oil density at standard temperature* 20^0C *and pressure 1 atm*;*

$\boldsymbol{\zeta}$ *– volumetric expansion coefficient (calculation value): a physical value that equals relative volume change at temperature alteration at* 1^0 *(Fig. 1.1);*

***** *– normal physical conditions – temperature* 0^0C*, pressure 1amp. or 0,101 mPascal; standard conditions for oil in England and America: temperature 15* ^oC*, pressure 1 amp, in Europe and Russia – temperature 20* ^oC*, pressure 1 amp.; gas – temperature 15* ^oC*, pressure 1 amp.*

To calculate crude oil density to pressure the following formula is applied:

$$\rho(P) = \rho_0 \left(1 + \beta(P - P_0)\right), \tag{1.2}$$

where $\boldsymbol{\rho_0}$ *– crude oil density at standard conditions;*

P *– pressure, Pascal;*

$\boldsymbol{P_o}$*– atmosphere pressuree, Pascal;*

$\boldsymbol{\beta}$ *– crude oil compressibility coefficient 0,00078 1/Pas.*

Gas density considerably depends on pressure and temperature. It can be measured in absolute units (g/cm^3, kg/m^3) and relative ones. At pressure 0,1 mPascal and temperature 0 ºC, gas density is approximately 1000 times less than fluid density and ranges from 0,0007 to 0,0015 g/cm^3 for hydrocarbon gases (depending on the gas content in light and heavy hydrocarbons). At standard pressure: P= 0,1013 mPascal and temperature: T=293K, natural gas density is approximately 0, 7 kg/m^3.

Relative gas density is the ratio of gas density at standard pressure (0,1 mPascal)and temperature (0 ºC) to air density at the same standard pressure and temperature values. Relative density of hydrocarbon gases ranges from 0.6……11.

Viscosity *– is a property of fluids that indicates their resistance to flow. Viscosity is classified as dynamic and kinematic.*

Dynamic viscosity (dynamic viscosity coefficient) $\boldsymbol{\mu}$ is fluid shear stress. Dynamic viscosity unit in SI is Pascal\ c**c – centipoises i.e. viscosity of a fluid (gas), where force acts across a surface of the body (1 m^2) and equals 1 Newton, if velocity between bodies at 1cm. changes to 1cm\sec. Thus, $\boldsymbol{\mu}$ depends on the physical interaction of fluid (gas) molecules.

Fluid with viscosity 1 Pascal\c. is a fluid with high viscosity. Most crude oil in Russia has dynamic viscosity coefficient from 1 to 10mPascal\c, bur there is crude oil with viscosity less than 1mPascal\c or even several thousands. Increased content of dissolved gas in crude oil affects its viscosity and significantly decreases it. For most crude oils in Russia viscosity increases 2 to 4 times given complete gassing (at constant temperature), but viscosity decreases as temperature increases.

Kinematic viscosity ν is dynamic viscosity divided by the density of the fluid and applied in operational calculations. Kinematic viscosity unit in SI is expressed in square centimeters per second (cm^2/sec). 1 centistoke corresponds to mm^2/sec.

When researching oil specific viscosity is usually defined as ratio of absolute viscosity of a given fluid η to absolute viscosity of distilled water η_o at the temperature 20^{0}C. Viscosity of crude oil and its products decreases as temperature increases. Under certain conditions it is simple to calculate viscosity at different temperatures. The dependence of viscosity to temperature is nonlinear to one specific oil product.

In comparison to fluid viscosity, gas viscosity depends on several specific operational parameters. Petroleum gas viscosity at pressure 0,1 mPascal and temperature 0 ºC is not more than 0,01mPascal·c. Gas viscosity increases as temperature increases and molar mass decreases. It is visa versa for fluids. Gas viscosity does not depend on pressure at 5…6 mPascals. Dynamic and kinematic viscosity is properties for gas and vapor, where the unit in SI is the same as for fluids (correspondingly, Pascal·c and m^2/c) Gas viscosity changing from temperature at atmospheric pressure can be expressed in Sutherland equation [1]:

$$\mu = \mu_0 (273 + C) \times \frac{\left(T/273\right)^{1,5}}{T + C}, \tag{1.3}$$

where $\boldsymbol{\mu_0}$ *– gas viscosity at normal conditions, Pascal\ c.;*

C *– constant (C value for several gases in Table 1.2).*

Hydrocarbon gas solubility in fluids- at ***invariable*** temperature, hydrocarbon gas solubility is determined by [2]:

$$S = \alpha P^b, \tag{1.4}$$

where ***S*** *– the volume of gas to the volume of a fluid at standard pressure and temperature;*

P *– gas pressure on a fluid (mPascal);*

α *– coefficient of gas solubility in a fluid indicating gas volume (at standard pressure and temperature), dissolved in a volume of fluid under pressure increase at 1 mPascal;*

b *– index indicating the variation degree of solubility of real gas from ideal gas. Values α u b depend on gas and fluid composition. Solubility coefficient α for crude oil and gas ranges from 5…11* m^3/m^3 *at 1mPascal. Index b ranges from 0,8…0,95.*

Table 1.2

C *value for gases*

Gas	C	Gas	C
Methane	162	Air	107
Ethane	252	Oxygen	127
Propane	290	Nitrogen	104
H–butane	377	Hydrogen	79
Isobutane	368	Carbon dioxide	254
H–pentane	383	Carbonic oxide	101

Thermal expansion. The coefficient of thermal expansion is the relative change of volume to a change in temperature. Thermal expansion is expressed as the ratio of volume change to initial volume after heating 1^0C. Thermal expansion (contraction) determinations require measurements of the volume of a given mass of oil at various temperatures – Joule\kg or Joule\m^3

Heat combustion is the amount of energy emitted during the heating of the volume of a given mass and is measured in Joule\kg or Joule\m^3. - the major coefficient for gas or fuels.

Critical and reduced thermal-dynamic parameters. Critical state defines the state of a substance at which the density of this substance equals its vapor saturation. Respectively, the parameters are called critical parameters.

If the pressure is increased at constant temperature, then at critical pressure, the gas condensates and is identified as liquid phase.There is a definite limiting temperature for each gas, above which liquid cannot be formed regardless of pressure.

Critical temperature (cricondentherm-Tct) – *is defined as the maximum temperature above which no gas can be formed into a liquid cannot be formed regardless of pressure.*

Critical pressure (cricondenbar Pch) *– is the maximum pressure above which no gas can be formed into a liquid regardless of temperature.*

For example, methane CH_4 consists of natural gas at $T_{crit.}$ = 190,55 K and $P_{crit.}$ = 4,641 mPascal (Table 1.3). In this case, if the temperature is above 190,55 K, then gas can not be formed into a liquid regardless of increased pressure.

Table 1.3

Physico-chemical parameters of gas

Gas	Molar mass kg/mole	Relative density of gas in air	Critical pressure, mPascal	Critical temperature, K
Methane	16.042	0.554	4.641	190.55
Ethane	30.068	1.049	4.913	305.50
Propane	44.094	1.562	4.264	369.80
Iso- butane	58.120	2.066	3.570	407.90
N-butane	58,120	2,091	3,796	425,17
N-pentane	72,146	2,480	3,374	469,78
Nitrogen	28,016	0,970	3,396	126,25
Oxygen	32,000	1,104	4,876	154,18

Hydrogen sulphide	34,900	1,190	8,721	373,56
Carbonic acid	44,011	1,525	7,382	304,19
Hydrogen	2,020	0,069	1,256	33,10
Helium	4,000	1,136	0,222	5,00
Air	28,966	1,000	3,780	132,46

Natural gas can be flammable or explosive if mixed with definite air ratio and heated to flammable temperature under conditions of open fire.

Minimum and maximum gas content in gas-air mixtures which can be flammable, are termed as upper \ lower explosibitity- boundary. This boundary is 5 to 15% for methane. This mixture is called ***detonating*** and the pressure is 0.8 mPascals.

Fractional parameters. Thermodynamic conditions of natural gas is described by average parameters, while the components – by fractional parameters.

Component mixture fractional pressure p_i *– that component pressure during its removal from the mixture volume, while excess component is at constant initial mass and temperature;*

Component mixture fractional volume v_i *– that component volume during its removal from the mixture, while excess component is at constant initial pressure and temperature;*

Gas laws. In comparison to liquid molecules, gas molecules are in significant distance from each other to their sizes. This fact indicates several specific features of gas properties. For example, compressibility, i.e. significant volume changes, significant pressure increase at temperature rise, etc. Kinetic theory of gases completely describes gas-substance behavior, which is based on the gas theories of Boyle- Mariotte, J. Guy-Lussac and Charl. All these laws are expressed mathematically by the following equation (Clapeyron- Mendeleev):

$$PV = nRT, \tag{1.5}$$

where $\boldsymbol{P}$ *– absolute pressure, Pascal =* $N/m^2 = kg\ m/c^2$*;*

$\boldsymbol{V}$ *– gas volume,* m^3*;*

$\boldsymbol{n}$ *– number of moles of gas, mole;*

$\boldsymbol{T}$ *– absolute temperature, K;*

$\boldsymbol{R}$ *– universal gas constant which for the above units has the value= 8,314Joule*m^3

The additivity principle is applied in calculating the physico-chemical gas properties, where gas is a multi-component mixture. Every separate component in the gas behaves as if was the only one. Applying this principle to Amaga and Dalton laws, it can be stated that gas mixture density equals the total density of all individual components, including component volume fraction. Overall gas mixture volume equals the total fractional component volume, including every component volume fraction. Overall gas mixture pressure equals the total fractional component pressure ***Pi***, including every component volume fraction, etc:

$$P = \sum P_i Y_i \ , \tag{1.6}$$

where $\boldsymbol{P_i}$ *– fractional pressure of individual mixture components, mPascal;*

Yi *– volume fraction of individual mixture components, %.*

The above-mentioned laws are convenient for ideal gases. Hydrocarbon gases and oil vapours are considered to be ideal gases at insignificant pressure. All mentioned laws can be applied in the calculations.

The magnitude of deviations of real gases from the conditions of the ideal gas law increases with increasing pressure and temperature and varies widely with the composition of the gas. Real gases behave differently than ideal gases. The reason for this is that the perfect gas law was derived under the assumption that the volume of molecules is insignificant and that no molecular attraction (repulsion) exists between them (i.e. Yan Diderik Van-der Vaals force: include momentary attractions between molecules, diatomic free elements and individual atoms. Because electrons have no fixed position in the structure of an atom or molecule, but rather are distributed in a probabilistic fashion based on quantum probability, there is a non- negligible chance that the electrons are not distributed and thus their electrical charges are not evenly distributed). This is not the case for real gases.

In order to express a more exact real gas relationship, a correction factor called the *gas compressibility factor (gas deviation factor) or simply, the z-factor* must be introduced into the previous equation.

Gas compressibility factor – *accounts for the departure of gases from ideality.*

$$P = Z\left(\overline{P}, \overline{T}\right)\rho RT, \tag{1.7}$$

where $\overline{P}\ \overline{T}$ *– dimensionless.pressure and temperature parameters.*

Individual component parameters *– dimensionless values indicate how the existing gas state parameters (temperature, pressure, volume, density, and others) are more or less than critical parameters:*

$$\overline{T} = \frac{T}{T_{кр.}}, \ \overline{P} = \frac{P}{P_{кр.}}. \tag{1.8}$$

The gas compressibility factor **Z** is a dimensionless quantity, determined either as a diagram or by the calculation method.

There are many approximation formulas to calculate the gas compressibility factor **Z**. As real gas properties are complex, there is no universal formula for all gases. Thus, different approximation formulas are applied in various situations. The most universal equation is as following:

$$Z\left(\overline{P},\overline{T}\right) \cong 1-0,4273\overline{P}\overline{T}^{-3,668}. \tag{1.9}$$

For relative pressure and temperature: $\boldsymbol{Z \approx 1}$ and ideal gas equation for gas system. If there are non-hydrocarbon components in oil gases (N_2, CO_2, H_2S), then correction must be introduced into the calculated value $\boldsymbol{Z}$ as special diagrams for these components.

***Gas adiabat (adiabatic curve) coefficient** – is the relative pressure change P to corresponding relative gas density change ρ ratio during the gas state transfer in the absence of thermal environmental exchange. Adiabat index for ideal gases is more than 1. Adiabat index value increases when the number of atoms in a gas molecule increases.*

Adiabat processes can be either reversible or irreversible. In reversible adiabat process the entropy system is constant. So, reversible adiabat system is termed as isoentropy. In irreversible adiabat processes entropy increases. Adiabat indexes are applied in gas expansion coefficient calculations and depend on the gas state parameters (pressure and temperature); and in the case of gas mixtures, then on mixture composition.

Adiabat throttling is the irreversible gas transfer process from high pressure to low pressure (expansion) during the gas flow through a narrowed cross-section (barrier with opening, porous partition) without external completion and communication and thermal-degeneration.

The process is quick, so environment heat exchange is practically absent and the substance enthalpy does not change. Thus, there is no useful work because pushing work transforms into the heat friction.

During adiabat flashing of real gas, in comparison to ideal gas, as a result of internal energy changes, the work is directed against molecule interaction forces. The change in gas temperature that occurs when the gas is expanded adiabatically from a higher pressure to a lower pressure is called ***Joule-Thompson effect*** (heating or cooling of a current-carrying conductor with a temperature gradient).

Depending on the initial real gas state before throttling, the gas temperature decreases, increases or remains without any changes.

The initial gas state point, where gas temperature during adiabatic throttling doesn't change, but the temperature effect index changes is called ***inversion point***. Temperature, corresponding to this point, is called ***temperature inversion***. Inversion point can be determined by plotting on the coordinates "temperature-volume" isobar and drawing a tangent to it from the reference point.

At initial gas temperature being less than inversion temperature, real gas during flashing cools; while at initial temperature being more than inversion temperature-heats.

Most gases, except hydrogen and helium, have a rather high inversion temperature (600 ºC and higher). Thus, adiabat flashing takes place at temperature decrease for practically all gaseous substances which are close to critical.

Non-hydrocarbon component and gas properties effect and the moisture in them Carbon dioxide and hydrogen sulfide in gases increases their moisture content. Nitrogen causes a decrease in moisture content, as nitrogen decreases gas mixture deviation from ideal gas and is less dissolvable in water. As gas molecular mass increases due to the amount of heavy hydrocarbons, gas moisture decreases because of heavy hydrocarbon molecule and water molecule interaction.

Hydration Natural gas, with saturated water vapors, at high pressure and definite positive temperature, can form hard compounds with water-hydrates. Gas hydrates are similar to compressed snow, having natural gas smell and can burn. Natural gas hydrates are non stable physico-chemical water compounds with hydrocarbons, which under conditions of temperature increase or pressure decrease decompose into gas and water.

Water molecules in the gas-hydrate structure form a lattice frame (in other words “master’s grid”), having “caves”. There are gas molecules in theses “caves”. (molecules – “guests”) Gas molecules are bonded to the water frame of van der Waals forces. Gas hydrate composition is described by the following formula: M_nH_2O, where ***M*** — gas-hydrate formation molecule, ***n*** — number of water molecules in one gas molecule, where ***n*** — variable number, depending on hydrate-formation type, pressure and temperature. There are three crystal modifications of gas-hydrates, as depicted in the following figures 1.1, 1.2 and 1.3.

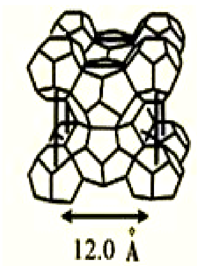


Fig.1.1. Structure I

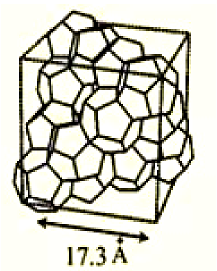


Fig.1.2. Structure II

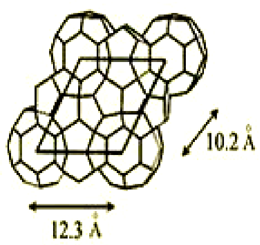


Fig.1.3. Structure H

Gas-hydrates form and exist under definite thermalbaric conditions. Due to its square structure, gas-hydrate volume 1 cm^3 includes up to 160—180 cm^3 pure gas.

Non-hydrocarbon component and gas properties effect on hydration. Hydrogen sulphide and carbon dioxide content percentage increase causes balanced temperature increase and balanced pressure decrease. For example, for methane, hydration temperature is 6 ^oC, at pressure 50 atm.; if H_2S content equals 25%, then the temperature is 10 ^oC. Natural gas, containing nitrogen, has a lower hydration temperature.

Hydration in *liquid hydrocarbon gases* is only under conditions of higher pressure and lower temperature. In comparison to natural gases, hydration in liquid hydrocarbon gases is a result of pressure system increase (in closed volume). In this case, heat emission takes places and, as a result, the system temperature increases. As the volume is constant, system pressure increases as temperature increases.

Hydrate decomposition of liquid hydrocarbon gases includes volume decrease, therefore, pressure decrease. Hydration in liquid hydrocarbons occurs slowly, in comparison to the same process in gaseous hydrocarbons.

In oil recovery, hydrates form in wells, oil field communications and gas pipelines. Settling on pipeline walls, hydrates significantly decreases their flow rate, thus, affecting the whole pipeline operation regime. To destroy hydrates in wells and gas pipelines, not only are different inhibitors (methyl, 30% CaCl2 solution) applied, but also, gas flow temperature above hydration temperature is maintained by heaters, pipeline isolation, and operation regime, providing maximum gas flow temperature. To prevent hydration in pipelines the most effective methods is gas dehydration – gas treating of water vapors.

Task and Discussion Questions

1. Define the oil mass in pipeline when: external diameter - 720 mm, length 10 km, wall thickness – 12 mm; oil temperature in the initial pipeline section - 50 ºC, in the final section - 25 ºC; pressure in the initial pipeline section - 5,5 MPa, in the final section – 4,0 MPa.
2. Calculate supercompressibility factor of gas mixture (methane – 92%, ethane – 5%, nitrogen – 1 %, hydrogen sulphide – 1 %, carbon dioxide – 1%) when pressure is 6,5 MPa and temperature is 30 ºC. Refer to Table 1.3. *Gas Characteristics.*

2. BASIC INFORMATION - HYDROCARBON QUANTITATIVE MEASUREMENT CHARACTERISTICS

Quality and quantity coefficients of fluid and gas hydrocarbons and its refining products are determining parameters commonly used both in gathering-distributing and reporting operations and in technological process monitoring of oil and gas transportation and storage.

Previous parameters, describing fluid gas hydrocarbon as well as their specific transportation, storage and control conditions determine additional requirements to the methods and technology in controlling transportation medium conditions.

Specific basic conditions are the following:

- High increasing cost of hydrocarbons and their refining products;
- Relatively significant of transportation medium volume;
- Affective requirements to fire-explosion safety of the technological process during transportation, storage and control.
- Various control variants and regimes for hydrocarbon transportation - from continuous to cyclic (episodic).

Physico-chemical parameter and quantitative medium characteristic measurements can be divided into two types: direct and indirect.

Direct measurements. In this case required parameter value (volume) is derived by applying measuring devices.

Indirect measurements. Based on the experimental direct measurement data of one or several values, related to the required value in a definite equation. For example, temperature measurement method by thermal resistivity where substance resistance changes according to temperature variations.

Measured medium temperature can be defined on the resistivity temperature ratio.

To receive the result in indirect measurements the measurement system (set of technologies) is applied. Depending on the requirements and objectives, this measurement system includes successive or parallel convertors, communication links, and measurement devices.

2.1. Fluid flow-rate measurement theory

2.1.1. Fluid and gas flow regimes

- Fluid and gas flow regimes can be divided into three types:
- *laminar;*
- *turbulent;*
- *transitional.*

Laminar flow is a fluid motion at a low flow velocity when separate fluid streams move parallel to each other. Laminar flow can be considered as a flow situation in which fluid moves in a parallel layers without particle mixing.

Turbulent flow is a fluid regime characterized by chaotic motion when the fluid particles move in a random manner mixing with each other. Turbulent flow takes place at high flow velocity. Despite the chaotic motion of fluid particles, definite tendencies can be stated.

Transitional flow is a mixture of laminar and turbulent flow. Transitional flow is characterized by intermittency that is the flow of turbulent and quasi-laminar fluid chains.

Many types of flowmeters, applied in transitional flow regime, can have unstable characteristics.

Fluid and gas flow regime depends on inertia viscosity flow ratio which is expressed by Reynolds equation:

$$\mathrm{Re} = \frac{D\overline{U}\rho}{\mu}, \tag{2.1}$$

where ***D*** – *internal conduit diameter, m;*

U – *flow velocity, m/c;*

$\boldsymbol{\rho}$ – *medium density, kg/c;*

$\boldsymbol{\mu}$ – *dynamic medium viscosity Pascal.c.*

Laminar flow takes place at Reynolds numbers less then 2000 while transitional flow – at 2000 to 4000. However, these border values are not exact. Laminar flow can change at 1200 Reynolds and be constant at Reynolds more than 2000.

When two fluid flows are geometrically similar (i.e. any corresponding linear dimensions of selected flows have the similar ratio), and the Reynolds (numbers) are equal, then these flows are dynamically similar, i.e. identical mechanical processes will occur with similar flow regimes. Therefore, many flow characteristics in the flowmeter are stated as Reynolds number function.

2.1.2. Fluid or gas flow continuity and Bernoulli's equations

Elementary fluid (gas) jet steady motion will be considered below (fig. 2.1.) Based on the mentioned above equations, the following definitions are determined:

Medium *– liquids or gases that flow and yield to any force tending to change their form; including dry saturated and superheated vapor. The amount or quantity of which is determined by (ГОСТ 8.586.1-2005).*

Volume flow rate *– the amount of quantity of a fluid (at operation conditions) that passes a point for a given time; usually expressed in* m^3*/sec,* m^3*/hr and etc.*

Mass flow rate *– a calculation of fluid flow through a pipeline orifice where the quantity of fluid is determined; usually expressed in kilograms mass per unit time (kg/sec., kg/hr etc).*

Volume flow rate under standard conditions *– the amount of quantity of a fluid at conditions according to ГОСТ 2939 (absolute pressure- 0,101325 mPascal, temperature 20 °C.*

Flow velocity and ***fluid state*** (i.e. density, pressure, and temperature) are constant at all points of the streamline in steady flow. Particle trajectory in such a flow is called ***streamlines***. Lateral jet surface called stream surface is impermeable for medium.

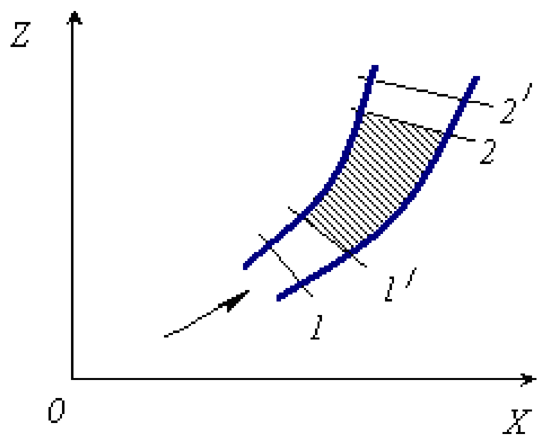


Fig. 2.1. Elementary fluid (gas) jet flow

Let us consider a jet segment between two streamline sections 1 and 2 relative to reference plane. According to the defined flow direction (fig. 2.1.), ***inlet flow*** is only in the cross-section 1, while outlet flow – in the cross-section 2.

Inlet flow through cross-section 1 in infinitesimal time dτ equals:

$$dQ_{m_1} = \rho_1 \cdot U_1 \cdot F_1 \cdot d\tau. \tag{2.2}$$

Outlet flow through cross-section 2 in infinitesimal time dτ equals:

$$dQ_{m_2} = \rho_2 \cdot U_2 \cdot F_2 \cdot d\tau\ , \tag{2.3}$$

where **ρ** – *fluid density, kg/m3;*

U – *flow velocity, m/sec;*

F – *flow cross-section area, m2.*

In steady regime when there is no fluid discontinuity its inlet flow equals outlet flow. Therefore, continuity equation (i.e. mass conservation law) with respect to isolated fluid jet in steady flow can be rewritten as:

$$\rho_1 \cdot U_1 \cdot F_1 = \rho_2 \cdot U_2 \cdot F_2. \tag{2.4}$$

Bernoulli's equation is an equivalent to the well-known law of energy conservation. According to Bernoulli's equation, the sum of specific mechanical energy in a fluid is the same along the streamline if a fluid is ideal.

Ideal fluid *if tangential stresses are absent inside a fluid, it means, there is no viscosity in this fluid.*

Specific kinetic **energy** is expressed by the following formula:

$$\frac{U^2}{2g}, \tag{2.5}$$

where ***g*** *– free fall acceleration, m/sec^2.*

Specific potential energy is the sum of specific state energy and specific pressure energy. Specific state energy is expressed by the height (h) of the flow jet section (normal surface against stream lines) to the horizontal reference plane.

Specific pressure energy *is a P/η ration (where* ***P****- absolute pressure, Pascal.c., that equals the sum of excess pressure P_{exc} and barometric pressure P_{bar};* ***η*** *– specific gravity, N/m^3. $\eta=\rho g$), corresponding to hydrostatic pressure P at the point.*

Consequently, Bernoulli's equation can be written for two selected flow jet sections (fig.2.2.).

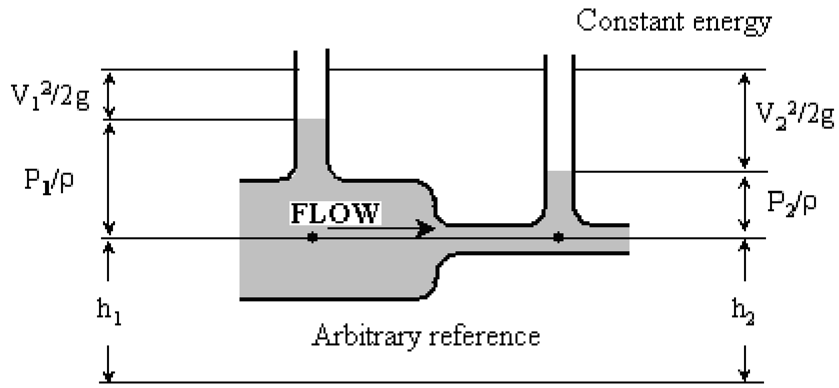


Fig. 2.2. Flow jet section

If $\eta=\rho g$, then Bernoulli's equation will be as:

$$h_1 \cdot g + \frac{P_1}{\rho_1} + \frac{U_1^2}{2} = h_2 \cdot g + \frac{P_2}{\rho_2} + \frac{U_2^2}{2}. \tag{2.6}$$

2.1.3. Theoretic outlet flow equation in pipeline orifice

Let us consider incompressible flow in pipeline orifice (fig. 2.3.).

If velocity profile along the flow jet section is even, height difference of two points is zero, that is $h_1 = h_2$ and fluid is incompressible ($\rho_1 = \rho_2$), then continuity and Bernoulli's equations will be expressed as:

$$U_1 \cdot F_1 = U_0 \cdot F_0 \text{ and } \frac{P_1}{\rho} + \frac{U_1^2}{2} = \frac{P_0}{\rho} + \frac{U_0^2}{2}. \tag{2.7}$$

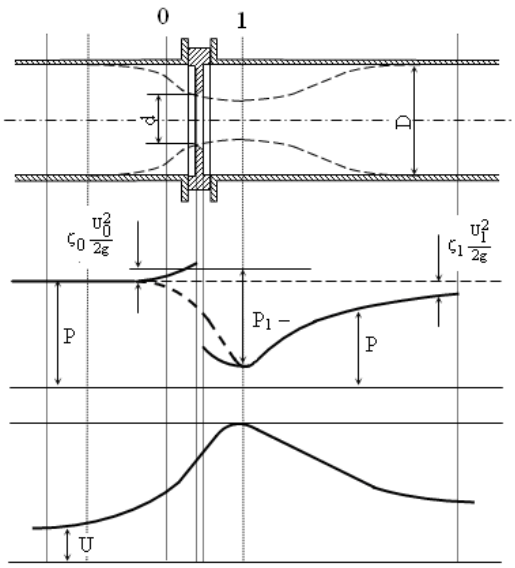


Fig. 2.3. Incompressible flow through orifice plate

The solution of the combine equations allows to derive the following theoretic equation for mass outlet flow calculation:

$$Q_m = \rho F_0 U_0 = F_0 \sqrt{\frac{1}{1-\left(\frac{F_0}{F_1}\right)^2}} \sqrt{2\rho(P_1 - P_2)}\,, \tag{2.8}$$

where coefficient $\sqrt{1/\left(1-(F_0/F_1)^2\right)}$, usually called inlet velocity coefficient and denoted by **E**, is a non-dimensional quantity [4,5].

According to [4] the inlet velocity coefficient value E the following formula can be determined:

$$E = 1/\sqrt{1-\beta^4}\,, \tag{2.9}$$

where $\boldsymbol{\beta}$ *– relative orifice diameter, determined as the ratio of orifice diameter* $\boldsymbol{d}$ *to internal pipeline orifice diameter* $\boldsymbol{D}$*.*

$$\beta = \frac{d}{D}\,. \tag{2.10}$$

2.1.4. Actual incompressible outlet flow equation in pipeline orifice

Actual outlet flow in pipeline orifice is not equal to theoretical one. It is due to the fact that when theoretic outlet flow equation is derived the measured flow is supposed to be ideal and incompressible without kinematic flow pattern consideration.

Let us consider actual incompressible flow in pipeline orifice – fig. 2.3.

Bernoulli’s equation for actual incompressible flow is:

$$\frac{P_1}{\rho_1} + \phi_1 \frac{\overline{U}_1^2}{2} + \psi_1 \frac{\overline{U}_1^2}{2} = \frac{P_2}{\rho_2} + \phi_2 \frac{\overline{U}_2^2}{2} + \psi_2 \frac{\overline{U}_2^2}{2} + \xi \frac{\overline{U}_2^2}{2}\,, \tag{2.11}$$

where $\boldsymbol{\psi_1}$, $\boldsymbol{\psi_2}$ *– inlet and outlet pipeline orifice velocity head fractures including measured and potential pressure value difference in sections 1 and 2;*

$\boldsymbol{\xi}$ *- flow friction coefficient;*

$\boldsymbol{\phi_1}$, $\boldsymbol{\phi_2}$ *– Coriolis coefficients (dimensionless quantities).*

Coriolis coefficients depend on flow velocity profile defined by Reynolds numbers and pipe wall roughness. In the case of turbulent and steady flow, Coriolis coefficients will be from 1,10 to 1,15. When the flow is unsteady, Coriolis coefficients can differ significantly from the unity. And they are close to the unity in pipeline orifice.

Coriolis coefficients equal to actual flow kinetic energy and average kinetic energy ratio:

$$\phi = \frac{\int_F U^3 dF}{\overline{U}^3 F} . \qquad (2.12)$$

Let us express by continuity equation,

$$\overline{U_0} \cdot F_0 = \overline{U_1} \cdot F_1 = \overline{U_2} \cdot F_2 , \qquad (2.13)$$

velocity values $\overline{U}_1$ *and* $\overline{U}_2$ *through velocity* $\overline{U}_0$ *in the orifice:*

$$\overline{U_1} = \overline{U_0} \cdot \beta^2 \text{ and } \overline{U_2} = \frac{\overline{U_0}}{\mu} , \qquad (2.14,\ 2.15)$$

where $\boldsymbol{\beta^2 = F_0/F_1}$ *– relative orifice area or relative orifice diameter;*

$\boldsymbol{\mu = F_2/F_0}$ *– flow contraction coefficient.*

Substitute U_1 and $\overline{U}_2$ values, expressed by velocity U_0 into equation (2.13) to obtain the following formula for mass outlet flow calculation:

$$Q_m = \rho F_0 \overline{U}_0 = F_0 \frac{\mu}{\sqrt{\phi_2 + \psi_2 + \xi - \phi_1 \beta^4 \mu^2 - \psi_1 \beta^4 \mu^2}} \sqrt{2\rho (P_1 - P_2)} . \qquad (2.16)$$

Multiply and divide the right side of the equation into the inlet velocity coefficient $E = \sqrt{1/(1-(F_0/F_1)^2)}$ *to obtain the following equation:*

$$Q_m = \rho F_0 \overline{U}_0 = F_0 C E \sqrt{2\rho (P_1 - P_2)} , \qquad (2.17)$$

where ***C*** *– outlet flow coefficient (dimensionless quantity), which equals to actual outlet flow value and its theoretic value ratio.*

The following formula is applied for outlet flow coefficient calculation:

$$C = \frac{Q_m}{\frac{\pi}{4} d^2 E \sqrt{2\rho \left(P_1 - P_2\right)}} . \qquad (2.18)$$

The formulas above (2.17), (2.18) imply that actual and ideal fluid equations differ in outlet flow coefficient presence in actual fluid equation.

Outlet flow coefficient value depends on the type of an orifice, Reynolds numbers, and velocity profile in pipeline. (Fig.2. 4).

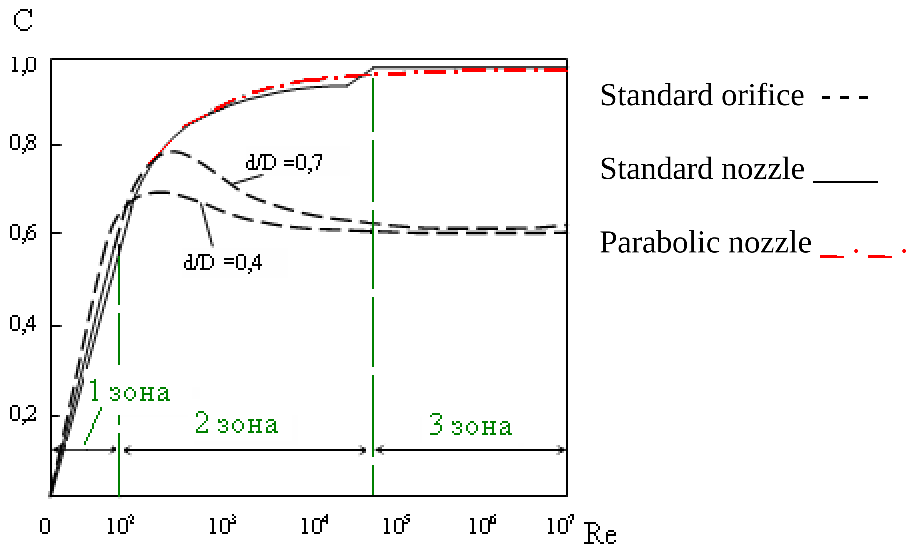


Fig. 2.4. Outlet flow coefficient and Reynolds numbers ratio for various orifices

As a rule, present outlet flow coefficient calculation methods are not enough accurate. Therefore, outlet flow coefficient values standardized in Russian and foreign normative documents are obtained/the results of in numerous, high-precision experimental investigations.

2.1.5. Actual gas outlet flow equation in pipeline orifice

It was assumed that measured medium density in pipeline orifice is constant. However, this assumption is applied to incompressible flow only. *In the case of gaseous medium it can lead to the significant errors.*

Gas outlet flow in pipeline orifice can be considered as adiabatic process (i.e. without heat emission and heat consumption). In this case gas density varies as adiabat:

$$\rho = \rho_1 \left(\frac{P}{P_1} \right)^{\frac{1}{k}}, \tag{2.19}$$

where, $\boldsymbol{\kappa}$ *– adiabate index,* which depends on gas type, its temperature, and pressure.

Differential form of energy conservation equation is:

$$d\frac{U^2}{2} + gdh + \frac{dP}{\rho} + dL_{mp} = 0, \tag{2.20}$$

where, $\boldsymbol{dL_{mp}}$ *– overcoming friction force work.*

Equation integration (2.20) results in:

$$\frac{U_2{}^2 - U_1{}^2}{2} + g(h_2 - h_1) + \int_1^2 \frac{dP}{\rho} + L_{TP} = 0. \qquad (2.21)$$

Equation integral (2.21) with (2.19) equals:

$$\int_1^2 \frac{dP}{\rho} = \frac{k}{k-1}\,\frac{P_1}{\rho_1}\left[\left(\frac{P_2}{P_1}\right)^{\frac{k-1}{k}} - 1\right]. \qquad (2.22)$$

Taking $L_{mp} = 0$, $h_1 = h_2$ together with continuity equation

$$\rho_1 U_1 = \rho_0 U_0 \beta^2 \text{ and } \rho_2 U_2 = \rho_0 \frac{U_0}{\mu_г}, \qquad (2.23, 2.24)$$

where $\mu_г$ *– gas jet contraction coefficient*

Allows us to derive the following mass outlet flow equation:

$$Q_m = \rho_0 F_0 \overline{U}_0 = F_0 E\sqrt{2\rho_1 (P_1 - P_2)}\sqrt{\frac{k}{k-1}\frac{P_1}{(P_1 - P_2)}\left(\frac{P_2}{P_1}\right)^{\frac{2}{k}} \frac{\left(1-\beta^4\right)}{1-\beta\,\mu_г{}^2\left(\frac{P_2}{P_1}\right)^{\frac{2}{k}}}\left(1-\left(\frac{P_2}{P_1}\right)^{\frac{k-1}{k}}\right)}. \qquad (2.25)$$

Multiply and divide the right side of the equation (2.25) into outlet coefficient value to obtain the following equation:

$$Q_m = F_0 C E \varepsilon \sqrt{2\rho_1 (P_1 - P_2)}, \qquad (2.26)$$

where ε *- spread coefficient.*

As gas density changes in pipeline orifice, correction factor ε for measured flow spread is introduced. The main parameter which defines ε is $(P_1\text{-}P_2)/P_1$ ratio, characterizing gas density rate ρ in pipeline orifice. The more $(P_1\text{-}P_2)/P_1$, the more significant are ρ changes, and the more significant is difference of expansion coefficient ε from the unity. When $(P_1\text{-}P_2)/P_1$ values are small, ε coefficient tends to the unity.

Since jet radial expansion can take place in the orifice that leads to tapering part area increase, expansion coefficient is always higher for the orifice than for the nozzle at the same $(P_1\text{-}P_2)/P_1$ value.

Expansion coefficient values ε can be calculated by the following formula:

$$\varepsilon = \sqrt{\frac{\kappa}{\kappa-1}\frac{P_1}{(P_1-P_2)}\left(\frac{P_2}{P_1}\right)^{\frac{2}{k}}\frac{\left(\phi_2+\psi_2+\xi-\phi_1\beta^4\mu^2-\psi_1\beta^4\mu^2\right)}{1-\beta^4\mu_{г}^2\left(\frac{P_2}{P_1}\right)^{\frac{2}{k}}}\left(1-\left(\frac{P_2}{P_1}\right)^{\frac{k-1}{k}}\right)}. \quad (2.27)$$

If area F_0 is expressed through the orifice diameter at flow operating temperature and $P_1 - P_2 = \Delta P$, then mass outlet flow equation will be:

$$Q_m = \left(\frac{\pi d^2}{4}\right) CE\varepsilon\sqrt{2\rho_1 \Delta P}\ . \quad (2.28)$$

Volume gas outlet flow formula for standard conditions is:

$$Q_m = \frac{Q_v}{\rho} = \frac{Q_c}{\rho_c}, \quad (2.29)$$

where ***Q_m*** *– mass outlet flow, кg/sec;*

Q_v *– volume outlet flow in operating conditions, m^3/sec;*

Q_c *– volume outlet flow in standard conditions;*

ρ_c *– gas density in standard conditions, кg/m^3.*

Then

$$Q_c = \left(\frac{\pi d^2}{4}\right) CE\varepsilon \frac{1}{\rho_c}\sqrt{2\rho_1 \Delta P}\ . \quad (2.30)$$

However, according to ***GOST 8.586.-2005***, mass gas outlet flow should be defined with regard to correction factors $K_{Ш}$ and $K_{П}$, that in contrast to the international standards [6] allows to improve gas and liquid outlet flow measurements with standard orifices:

$$Q_m = \left(\frac{\pi d^2}{4}\right) K_{Ш} K_{П} CE\varepsilon\sqrt{2\rho_1 \Delta P}\ , \quad (2.31)$$

where $K_{П}$ – correction factor, taking into account orifice entrance edge dulling;

$K_{Ш}$ – correction factor, taking into account orifice internal surface roughness (Fig. 2.5, Fig. 2.6).

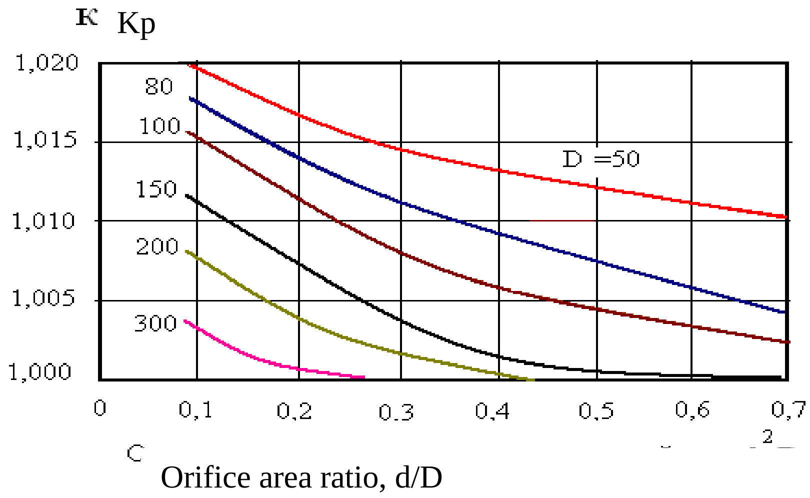


Fig. 2. 5. Orifice entrance edge dulling correction factor Кр and pipeline diameter and orifice area ratio

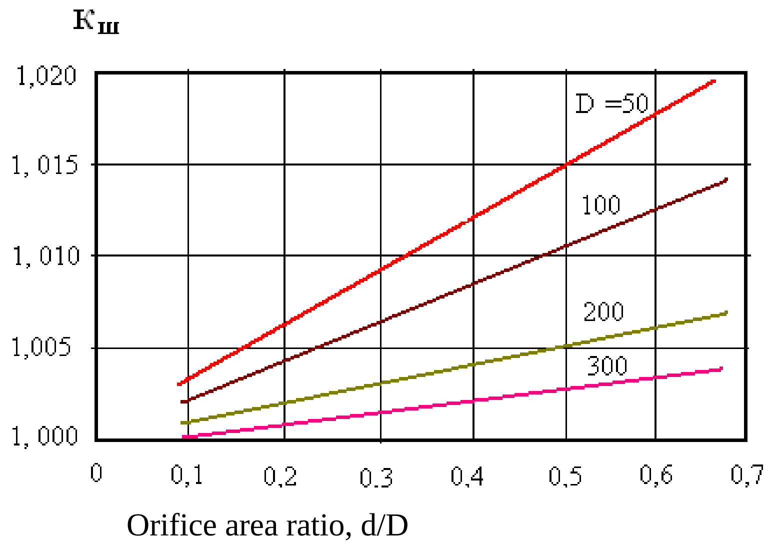


Fig. 2. 6. Orifice internal surface roughness correction factor $K_{Ш}$ and pipeline diameter and orifice area ratio

2.2. Control-Measurement Devices for Hydrocarbon Quantity

The control of hydrocarbon and refined product quantities requires the determination of bulk or mass characteristics by applying direct or indirect methods. These methods are applied to determine product mass by scales, scale dosimeters and devices, volume meters, flow meters with indicators. All methods are subdivided as bulk-density and hydrostatic.

Bulk-density method is the measurement of product volume (***V***) and density (***ρ***) at the same or stated conditions (according to temperature and pressure), determination of gross product mass as a variable meaning of this value and further calculation of mass netto gives:

$$M_{бр} = V_{pt} \times \rho_{pt}, \qquad (2.32)$$

where, $\boldsymbol{M_{бр} = M_{gross}}$ *– gross product mass, m;*

$\boldsymbol{V_{pt}}$ *– product bulk, m*^{3}*;*

$\boldsymbol{\rho_{pt}}$ *– product density to mass measurement conditions, m/m*^{3}.

Product density is measured either according to flow densitometers, based on different physical principles or hydrometers (aerometers) for crude oil and oil products at laboratory conditions, i.e. combined (average) samples from a sampler with further mixing before density measurement. Product temperature and pressure through density and mass are measured by thermometers and manometers.

When determining product mass netto, the mass ballast is defined. Thus, the water content and chloride salt concentration in oil is determined and their mass is calculated. Mechanical impurity mass is determined as the average mass fraction in oil, according to existing standards, technical requirements and other documents.

Water content in oil and chloride salt concentration is determined by flow moisture (hydrometers) meters and salt meters, respectively; or by combined (average) crude oil samples conducted in laboratories.

According to calculations, product mass netto is determined as the difference between gross oil mass $\boldsymbol{M_{gross}}$ and ballast mass $\boldsymbol{M_{ballast}}$:

$$Mnetto = Mgross - Mballast \qquad (2.33)$$

Depending on the measurement method of product volume, bulk-density method is divided into the following types: ***dynamic, static and hydrostatic***.

Dynamic method is applied to measure the product mass directly in the flow through oil- and product pipelines. i.e. the product volume is measured by flowmeters, or simply, meters.

Static method is applied to measure the product mass in calibrated tanks (vertical and horizontal reservoirs, transport tanks, etc.). Product volume in tanks is determined by reservoir calibration tables, according to the bulk level measured by level gauges (indicatorss), roto-meters or steel measuring tapes. Product volume level in calibrated bulk capacity tanks is determined according to technical requirements.

Hydrostatic method is applied to measure the product hydrostatic pressure column and determines the average area of the filled reservoir at a specific level. Thus, the product mass is the sum of these values divided by gravity. Product mass M can be written as:

$$M = \frac{p\,F_{average}(H_p)}{g}, \qquad (2.34)$$

*where **p** – hydrostatic pressure of the product in the reservoir (tank), Pascal;*

$\boldsymbol{H_p}$ – calculation filling–up level or level which can be measured, m;

$\boldsymbol{F_{average}}$ (H_p) – average reservoir cross-section area, determined according to the reservoir calibration tables;

***g** – gravity.*

Unloaded and loaded product mass can be determined in the following two ways:

- mass difference, determined at the beginning and end of the commodity operation (applying above-mentioned method);
- difference product between hydrostatic pressure at the beginning and end of commodity operation and average reservoir cross-section area, where the unloaded oil product is divided by the local gravity force.

Hydrostatic pressure of the products is measured by manometer devices including vapor pressure of oil/oil products.

In determining the average reservoir cross-section area by metal retractable pocket rule, rod or level meter, product level at the beginning of commodity operation is measured. Further, corresponding average cross-section areas of product level is calculated in accordance to reservoir calibration table.

Applying *dynamic method*, many flowmeters (gauges) are used not only for flow measurement, but also for mass or volume measurement of the substance at any specific time interval. In this case, these devices are called ***flowmeters*** or simple ***meters*** (GOST 15528-86). The following terms should be introduced to define measured substance, e.g. gas flow meter, fluid flow meter, vapor volumeter, gas volumeter.

*The device (diaphragm, nozzle, and pressure tube), measuring and converting the flow into another value (e.g. pressure drop), being more convenient for measurement, is called **flow transducer*** [3].

This term was adopted according to ***GOST 15528 - 70*** and basic metrology terminology ***GOST 16263 – 70***. Based on these documents measured devices are divided into two groups:

- *measurement transducers;*
- *measurement devices.*

Flow transducer is an excellent example of the first group of measurement devices.

When pressure and temperature are known, substance value (especially gas) can be precisely defined by volume. So, volumetric gas flow measurement results are reduced to standard conditions, i.e. temperature - 293,15 K and pressure 101 325 Pa.

Control-measurement devices are intended for to compare the measurement parameters to the unit of measurement. They provide monitoring and analysis of production equipment, as well as, measurement of several oil and gas physico-chemical parameters, which, in its turn, determines the measurement of quantitative and qualitative parameters of moving fluid. For instance, to calculate precisely fluid flow, it is necessary to determine the basic variable parameters: density, composition, viscosity, and temperature.

The main characteristic of all control-measurement devices is accuracy class, i.e. major permissible measurement error. Class accuracy is characterized by the ratio of device maximum absolute error and measurement limit expressed in percentage. Technical device accuracy class: 0,2; 0,5; 1; 1,5; 2,5. Laboratory instrument accuracy class: 0,05; 0,1; 0,2.

Control-measurement device (CMD) classification is divided into:

1. according to measurement value:

- *pressure measurement instruments (barometers, manometers, vacuum gages);*
- *temperature measurement instruments (thermometers and pyrometer);*
- *flow measurement instruments (meters, flow meters);*
- *level measurement gauge (level indicators, level gages).*

2. according to such parameters as [7]:

- *metrological application: technical, laboratory (operating), standard;*
- *output signal type: indicating, recording, integrating (summation);*
- *operation mode: liquid, mechanical, pneumatic, electronic;*
- *operation conditions: stationary, portable;*
- *overall dimensions: small-size, large-size.*

Considering ***metrological application***, standard devices are intended for verification and calibration of other measurement instruments. All control-measurement devices should be controlled in accordance to state or technical requirements. Standard device accuracy class is 0,005; 0,02; 0,05. Metrological supervision provides constant monitoring of measurement device requirements, working conditions and reading correctness; excluding the out-of-date and faulty instruments.

Technical devices are intended for working conditions. Reading accuracy correction is not included in such measurement instruments. Accuracy class of most technical devices ranges from 0,25 to 2,5.

Laboratory devices are used for precise measurement in laboratory conditions. Reading corrections for measurement conditions (ambient temperature, atmosphere pressure, and humidity) have to be made for accurate measurement. Besides, laboratory devices are applied for technical instrument testing. Laboratory accuracy class is 0,05; 0,1; 0,2.

Measurement parameter value in *indicating devices* is read by a linkage connected to an indicating needle presented in a scale (including ***output signal***). Despite the design simplicity of these devices, they read the value of measurement parameter only at the moment of measurement, excluding the possibility of monitoring parameter changes in time. Most indicating devices have fixed scales and moving indicator needles. Some devices, vice verse, have sliding scale with fixed indicating needle. Such a construction significantly decreases overall dimensions of the instrument. The reading can be shown at a digital indicating unit. In this case, measurement results are independent of the human factor.

Based on the record characteristics (either band or disc), all the changes of a measurement value are defined.

Recording devices record measurement data automatically either by disc or band charts during the whole operation period at a constant speed which makes it possible to monitor the pattern of parameter change in time. Disc chart usually records only one parameter, while band chart alternately records several parameters. Such devices are called multipoint instruments and intended for 3, 6, 12 measurement points.

Integrating devices continuously integrate/summarize instantaneous values of a measurement parameter through a register (e.g. electrical). Measurement null method with automatic balancing is applied to increase measurement accuracy. Such measurement instruments operate as automatic compensators, and, like booster converters, are designed according to astatic follow-up system.

Most modern control-measurement devices systems with

- *primary transducer;*
- *secondary transducer;*
- *linkage*.

Primary measuring transducer is the first to contact with the measured fluid, and sometimes called *sensors.*

The part of primary measuring transducer being directly affected by a measurement value is called ***sensing element***.

Primary transducer is installed directly in the area of in which the flow parameter should be determined. Primary transducer and sensing element contact with the fluid and, in its turn, convert the measurement value of this fluid into physical value. For example, resistance and thermoelectric thermometers are connected to such secondary devices as potentiometer and bridges [8].

One and the same control-measurement device can be applied for different value determination. For instance, depending on the transducer type, voltmeter can measure temperature, gas composition and etc.

2.2.1. Pressure Meter Classification

Pressure is a quantity which characterizes most technological processes and is transmitted to solid boundaries or across arbitrary sections of fluid normal to these boundaries or sections at every point. For gases or liquid, pressure is one of the fundamental parameters which characterizes the internal fluid energy. The SI unit for pressure is Pascal (Pa), equal to one Newton per square meter (N/m^2). Manometer scales can be calibrated in kilopascal (kPa) or megapascal (MPa), also in kilogram-force per square centimeter or metre (kg/cm^2, kg/m^2), barye, mm Aq, mm Hg and etc.

The following pressure types are distinguished: absolute, excess, and gauge.

Absolute pressure $\boldsymbol{P_{abs}}$ *is zero referenced against a perfect vacuum, so it equals to atmospheric pressure* $\boldsymbol{P_{atm}}$ *plus excess pressure* $\boldsymbol{P_{exc}}$*:*

$$P_{абс} = P_{изб} + P_{ат}. \tag{2.35}$$

When pressure is below atmospheric, gauge pressure is introduced [8]:

$$P_{в} = P_{атм} - P_{абс}. \tag{2.36}$$

Differential pressure (ΔP) *– is the difference in pressure between two points of measured or ad hoc referenced medium (fluid) which affects the sensing element of a differential manometer* [9].

Maximum permissible working excess pressure *– excess pressure for specific manometer operation life.*

Nominal static characteristic *– differential pressure and disk, output signal or scale index ratio.*

Manometer – *is a pressure measuring instrument usually limited to measuring pressures near to atmospheric.*

Table 2.1.

Pressure units

Unit	1 kilogram-force/cm^2	1 kg/m^2	1 mm. Hg	1 bar
Pascal	98066,=0,1 MPa	9,8065	133,322	10^5

Depending on measured pressure, the following types of manometers are distinguished (Fig. 2.7).

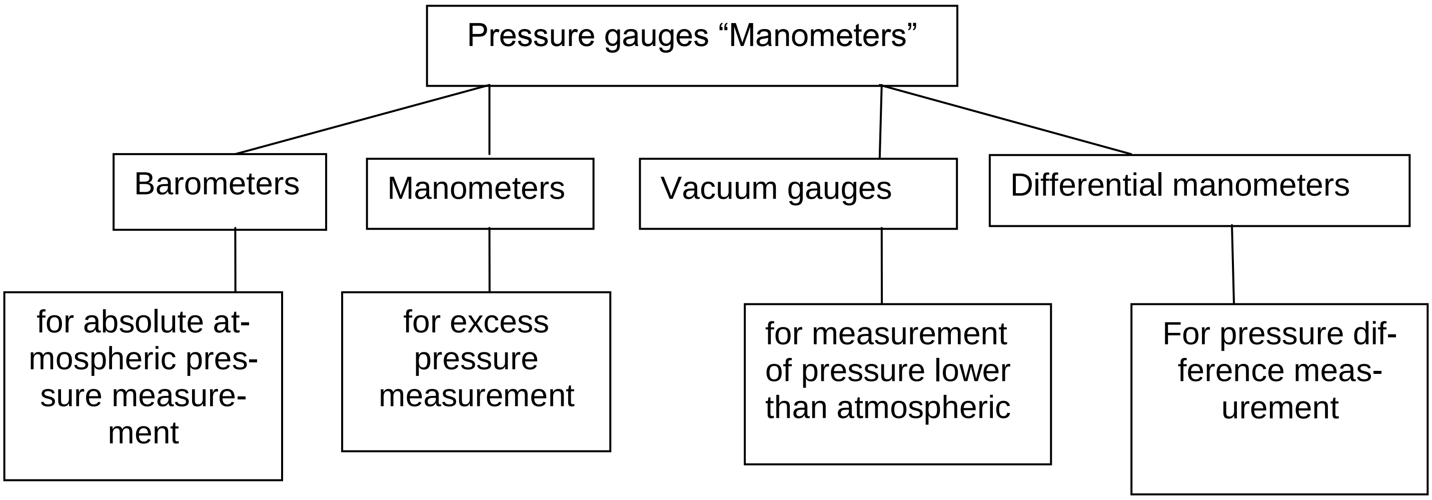


Fig. 2.7 . Pressure measuring instrument classification

Manometers used for pressure measuring or vacuum in the range of 0,04MPascal (0,4 kilogram-force/cm^2) are called *head gauges* and *draft gauges*.

Based on the conversion of pressure force effecting the sensing element, and expressed in readings or corresponding units of another physical value, manometers and differential manometers can be classified as:

- *hydrostatic manometers compare pressure to the hydrostatic force per unit area at the base of a column of fluid;*
- *elastic element gauge counterbalance the pressure with reversible deformation force of the tube spring, membrane or rolling diagram;*
- *piston manometers counterbalance the pressure of a fluid with a solid weight or spring.*

According to the registry/calibration, pressure gauges are either direct- or indirect-reading gauges. Direct reading gauges are used to measure the pressure of a gas. They are irrespective of the gas being measured, f.e. hydrostatic manometers, but are indirectly dependent of the temperature. Indirect reading gauges measure not the pressure itself, but gas properties. Such readings are dependent on the gas type being measured and gas temperature. [10].

Pressure gauges can be pressure transmitters with uniform pneumatic and electric responses which are widely applied in automatic technological process control systems.

Pressure transducers should operate safely under violent vibrations, transient temperatures, and electromagnetic fields, as well as, in corrosive environments and high-humid, dust-laden and gas-laden environments. Based on above-mentioned factors, all differential pressure measuring instruments [9] can be classified as (Fig. 2.8):.

Differential manometers are manufactured with additional devices for signaling, control and flow rate integration, pneumatic or electrical signal transformation and transmission, as well as, pressure and temperature recording.

Differential manometer permissible basic error, expressed in percentage to critical value, must correspond to: ±0,25% accuracy class - 0,25; ±0,5% accuracy class - 0,5; ±1,0 % accuracy class - 1; ±1,5% accuracy class - 1,5.

If differential manometers are designed with indicating gauges, then the integrator permissible basic error is ±0,6 and ±1,0% to maximum scale value or diagram disk (chart strip).

When ambient temperature changes every 10 °C, the indications (records or responses) depending on the accuracy class should not exceed the values as stated in Table 2.2.

Differential manometer dead zone should not exceed the absolute value of permissible basic error limit.

Dead zone *- maximum differential pressure variation interval when the indications (records and responses) are constant.*

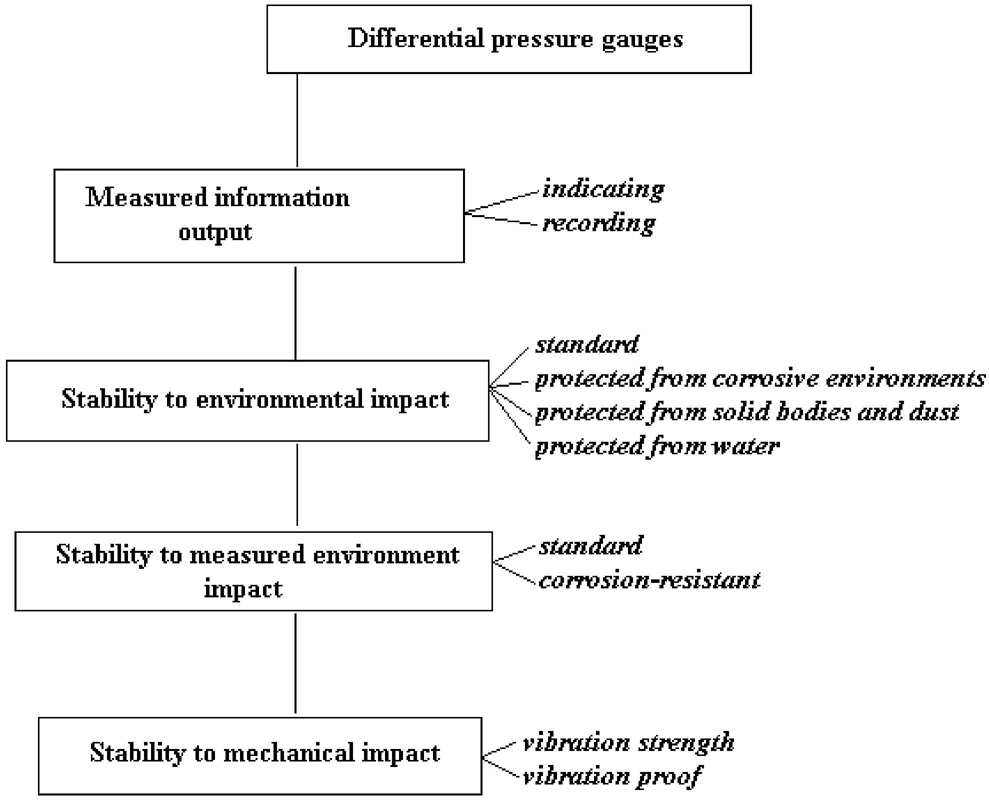


Fig. 2.8 . Classification of differential pressure gauges

Table 2.2.

Differential manometer indication changes according to accuracy class

Accuracy class	Permissible indication changes (records or responses) to the absolute value of permissible basic error limit.
0,25	1,2
0,5	0,9
1	0,6
1,5	0,5

Hydrostatic manometers. Hydrostatic manometers counterbalance the pressure or pressure difference by the pressure of a liquid column. Hydrostatic gauges are based on the law of connected vessels. Hydrostatic and differential manometers can be:

- *visible level of working liquid inscribed with the pressure indications (laboratory and industrial test instruments);*
- *invisible level of working liquid indicated by the float moving and characteristic changes of other devices inscribing either measured quantity values or its value transformation and transmission at distance.*

Hydrostatic and differential manometer types:

- *U-tube manometer;*
- *Well-type manometer.*

The advantages of the hydrostatic and differential manometers are their simplicity, reliability, and high accuracy. When using such pressure measuring instruments, the overload and pressure jump are prohibited so as to prevent the working liquid from splashing out into the column or atmosphere.

U-tube manometers – hydrostatic manometer which consists of connected tubes where the difference in liquid level represents the applied pressure. [11].

The pressure or pressure difference of a medium (fluid) being measured is defined by fluid height ***h*** in a liquid column (Fig. 2.9).

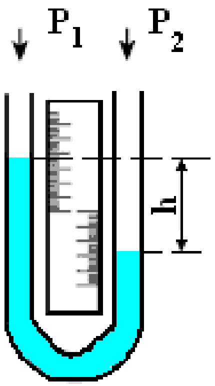


Fig. 2.9. U-tube manometer

Two connected vertical tubes, usually glass, are fixed to the base with the scale. One tube is connected with the region of interest whilst the reference pressure (which might be the atmospheric pressure) is applied to another one. When measuring pressure difference, both tubes are connected to the pressure being measured.

A liquid column, height **h** counterbalances the pressure difference:

$$P_1 - P_2 = \rho g h; \; h = \frac{1}{\rho g}(P_1 - P_2), \qquad (2.37)$$

*Where, **ρ** – working fluid density, кg/m*^{3}*;*

***g** –free fall acceleration, m/sec*^{2}.

Working fluid is considered to be the *sensing element* of hydrostatic manometers.

Level difference is an output value, while pressure or pressure difference – input value. Static characteristic curve depends on working fluid density. As the density increases, the measuring instrument sensitivity decreases. U-tube manometer calibration is defined by design geometry and working fluid density. Measurement accuracy is ±2 mm.

Water is a commonly-used liquid in U-tube manometers for measuring pressure, air and non-aggressive pressure difference ranging up to ±10 kPa. When mercury is used, the measurement range is up to 0,1 MPa, even if non-aggressive fluids and gases are being measured.

When hydrostatic differential manometers are used for measuring static pressure up to 5 MPa, additional devices are embedded for initial fluid level control and measuring instrument protection from one-sided static pressure.

Well-type manometer. Well-type manometers are used for accuracy increase when working fluid level difference is measured (Fig. 2.10). The second tube of a well-type manometer is a relatively big reservoir with high pressure.

A tube marked with a scale is a measuring tube which is connected to atmosphere. When measuring pressure difference, it is connected to low pressure. A working liquid column height measurement in well-type and differential manometers leads to measurement accuracy decrease.

Well-type measurement range is ±1 mm, while division value is 1 mm.

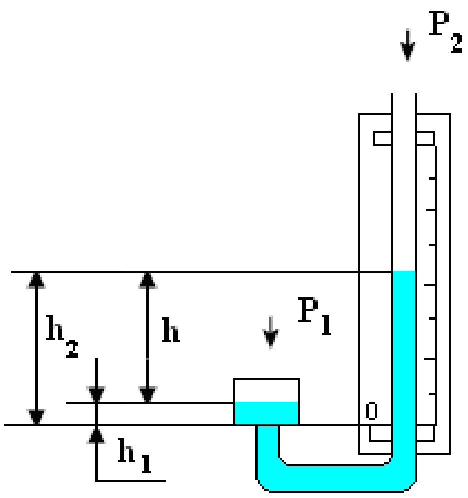


Fig. 2.10. Well-type manometer

Micromanometers. Micromanometers, *well-type manometers*, are used to measure pressure and pressure difference up to 30 MPa (300 kilogram-force/cm^2) (Fig. 2.11.). Micromanometers have special devices for division value decrease or for level height reading accuracy increase due to optics or other devices. They are usually called inclined-tube manometers. The most widely-spread laboratory micromanometers are MMH micromanometers with inclined measuring tube.

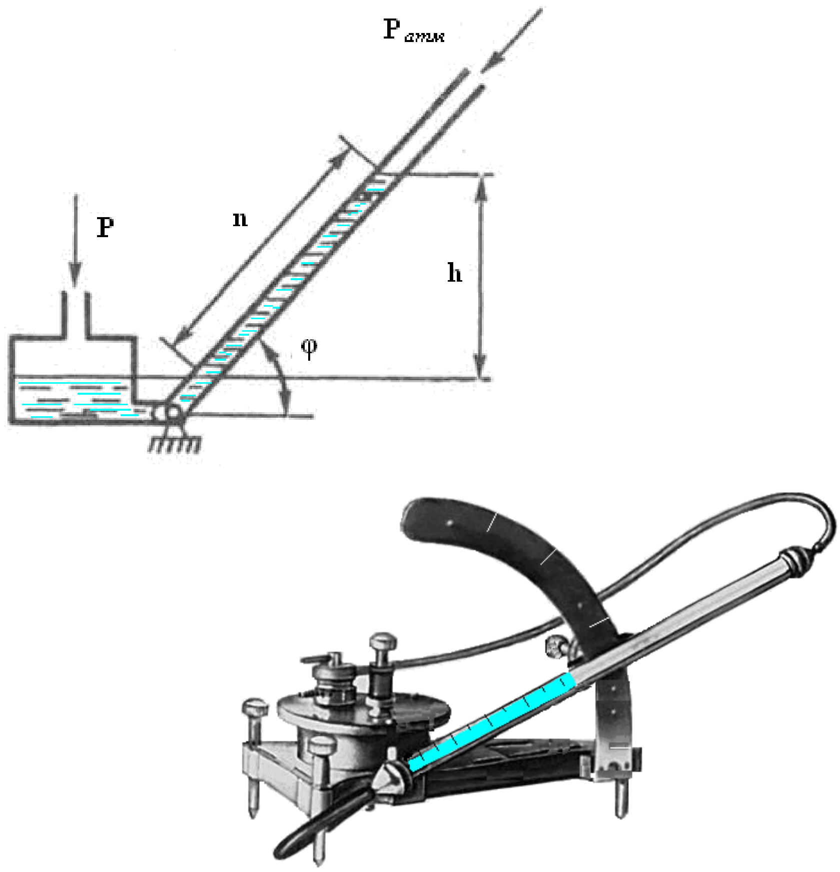


Fig .2.11 . MMN micromanometer

Micromanometer readings are determened by working fluid column length ***n*** in the measuring tube ***l***, inclination angle $\boldsymbol{\varphi}$. Based on the working fluid volume equation, working fluid displaced from the tube into the measuring tube is:

$$h_2 = n \times \sin \varphi . \qquad (2.38)$$

Most accurate MM measuring instruments are called compensating or double-leg manometers. Micromanometers with upper-range value is $2{,}5 \cdot 10^3$ Pa have 0,02…0,05% accuracy. For low pressure differences (up to 10^4 Pa) light fluids are used (water, spirit/alcohol, toluol, and silicon oil). When the upper-range value is increased up to 10^5 Pa, mercury is used. Measurement accuracy is ±2 mm.

Barometers. A tube containing mercury and a marked scale can be used as a simple barometer – an instrument for atmospheric pressure measurement. Atmospheric pressure at sea level is typically about 760 mm Hg. When mercury temperature is 0 °C, the pressure is called *standard atmospheric pressure* and is expressed in pressure units – Pascal:

$$P = \rho\, g\, h = 760 \ mm\ Hg\ (or\ 0{,}1\ mPascal). \qquad (2.39)$$

There are different designs of barometers. The most widely-spread barometers are cistern barometers with Hg calibration (Fig. 2.12). Aneroid barometers, a sealed chamber with a low pressure, are widely used in everyday life. As atmospheric pressure increases, the membrane deflects inwards and vice verse, - atmospheric pressure decreases, the membrane to deflect outwards. Any membrane deflections are shown by an indicating needle connected to the membrane (Fig. 2.13).

Compression pressure gauges *–hydrostatic manometer where vacuum gas is compressed by mercury for its absolute pressure measurement* [11].

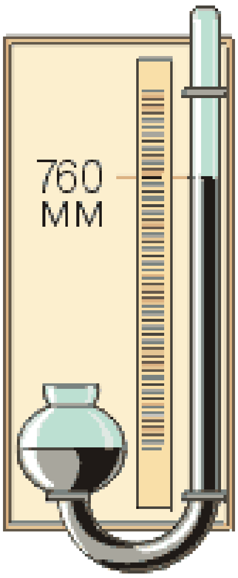


Fig.2.12. Cistern barometer

Fig. 2.13. Aneroid barometer

The measurement principle of compression pressure gauge is similar to U-type manometer. The only difference is that gas which equals the measured value *P* is compressed at initial pressure and measured as pressure difference between two tubes is measured. Thus, liquid level in one arm rises while the level in the other drops. A set of calibrated markings beside one of the arms permits a pressure reading to be taken (Fig.2.14).

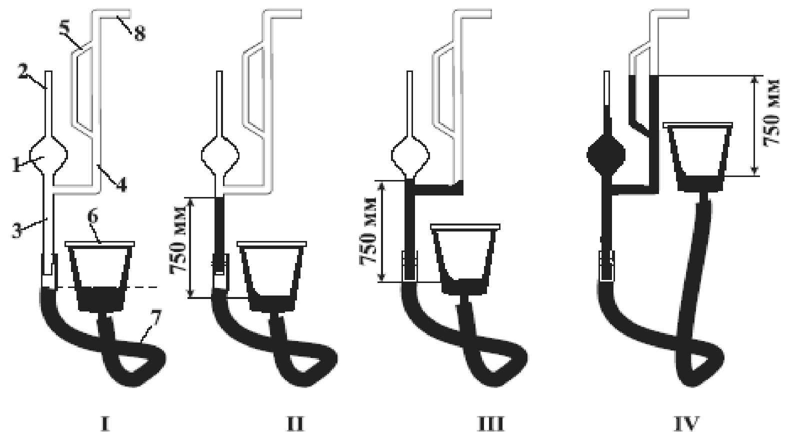


***Fig. 2.14. Operation procedure of compression pressure gauge**:*
1 – vessel; 2 — sealed measuring capillary; 3 — glass tube; 4 — vacuum branch; 5 — comparative capillary; 6 — mercury vessel; 7 — connection hose; 8 — tube connected to vacuum.

When measuring pressure by McLeod gauge, either linear or square-law calibration is applied. According to the linear calibration method, gas is compressed to a fixed point. [10]:

$$P_1V_1 = (P_1 + h)V_2 . \tag{2.40}$$

If low pressures *P1 << h,* then:

$$P_1V_1 \approx hV_2 ,\ P_1 = \frac{V_2}{V_1}h . \tag{2.41}$$

When applying square-law calibration method, mercury is at certain level in comparative capillary (***5)*** respective to the top of a measuring capillary (***2).*** Gas volume after compression is determined as:

$$V_2 = \pi r^2 h , \tag{2.42}$$

where, h – mercury level difference in measuring and comparative capillaries:

$$P_1 = \frac{V_2}{V_1}h = \frac{\pi r^2}{V_1}h^2 . \tag{2.43}$$

Float-type manometers. Float-type manometers and differential manometers counterbalance the pressure with the gravity of a working fluid column. These manometers are the manometer types which have not the visible level of a working fluid. The measured pressure is not the height of a liquid column, but by the position of the moving element in the instrument. Mercury or silicone oil is a typical working fluid in float-type manometers. Measurement range (from $4 \cdot 10^3$ Pa to 0,16 MPa) is the changing height and diameter of one differential manometer vessel. Accuracy is not more than 2,5% of upper-range value. These measuring instruments are widely-used in the gas industry.

Float-type manometers are used together with the orifices for differential pressure measurement. (Fig. 2.15).

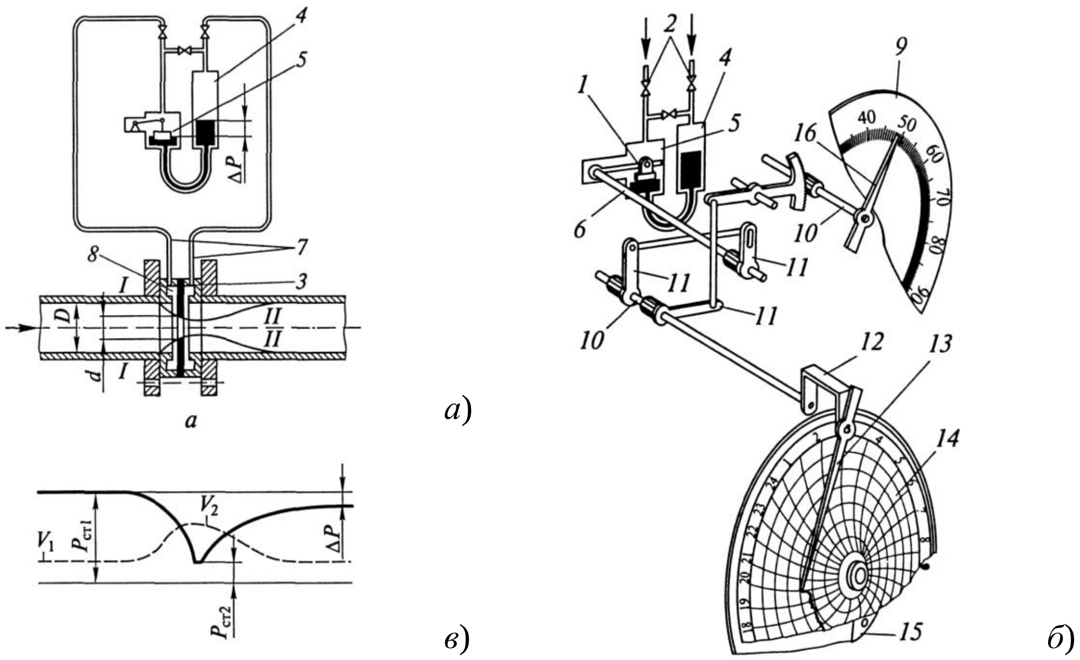


Fig. 2.15. Float-type manometer: a) – design; b) – kinematic diagram; c) – gas changing parameter plot; 1 – float; 2 – shutoff valves; 3 – diaphragm; 4 – vessel; 5 – float chamber; 6 – axle; 7 – impulse tubes; 8 – annular space; 9 – scale; 10 – axles; 11 – levers; 12 – bridge; 13 – pen; 14 – dial card; 15 – clock mechanism; 16 – needle

As flow rate increases, its kinetic energy increases and, respectively, potential energy decreases. Due to the pressure difference $\Delta P = P_1 - P_2$ mercury in the float-type manometer moves from float chamber (***5)*** into vessel (***4).*** Thus, the float (***1)*** descends and moves the axle (***6***) which, in its turn, is connected to the needles **(16) -** indicating gas flow rate and indicating differential pressure. Dial card (***14)*** is driven by the clock mechanism **(15)** and completes one rotation per day. Dial card divided into 24 sections indicates the gas flow rate per hour. Safety valve under the float disconnects the vessels (***4)*** and (***5),*** in the case, of abrupt differential pressure and, in its turn, prevents mercury outburst.

Vessels are connected to the diaphragm impulse tubes through shutoff valves 2 and pressure-control valve which should be shut down at operating position.

Therefore, orifice differential pressure, measured by differential manometer *according to 2.30 and 2.31 equations,* ***can indicate gas flow rate***. Thus, gas volumetric content dependence can be simply expressed as:

$$V = K\sqrt{\Delta P}\,, \qquad (2.44)$$

where, ***V*** *– volumetric gas discharge, m*^{3}*;*

ΔP *– differential pressure, Pa;*

K *– constant coefficient, depending on an orifice plate and pipeline diameters to gas density and viscosity ratio.*

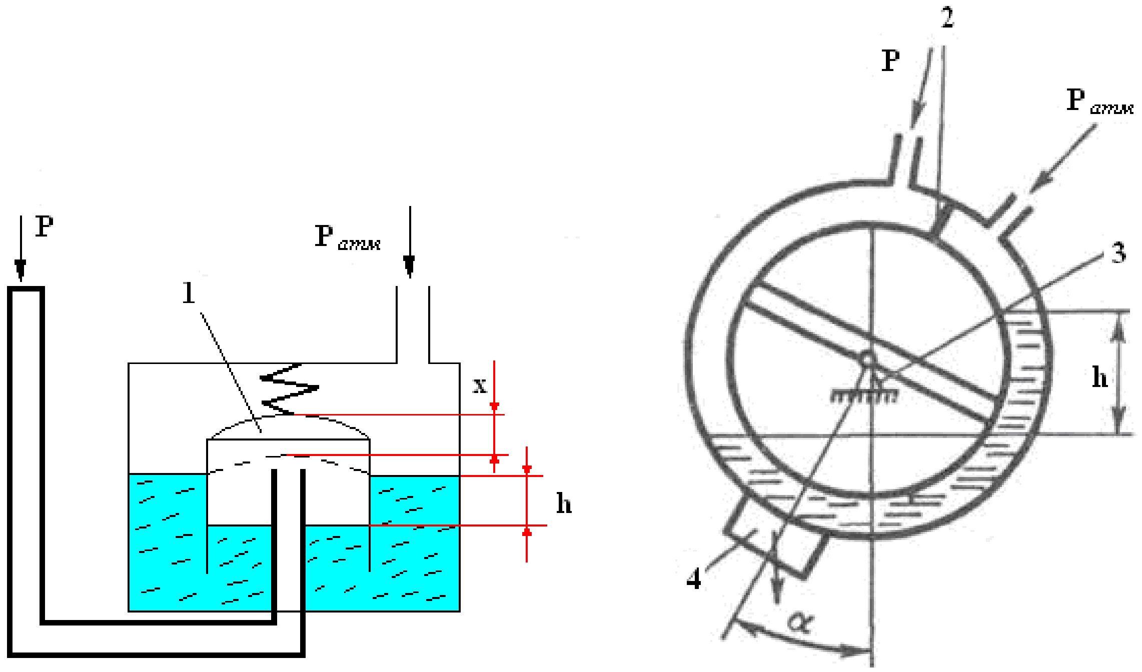
Bell-type and ring-balance manometers. ***Bell-type manometer*** *– measures the pressure by the moving bell submerged into the liquid, or by developing force due to measured pressure.*

Ring-balance manometer – *differential manometer which indicates the differential pressure by ring rotation angle or by moment of force created by the suspended weight to the ring. [11].*

Similar to the float-type manometers, the pressure in bell-type and ring-balance manometers is determined not by the height of a liquid column, but by the position of the moving element in the instrument. (Fig. 2.16).

Bell-type manometers (working fluid is water or oil) are intended for small pressures or differential pressures ranging from 25 to 400 Pa. The accuracy is 1,5 and 2,5% of measurement range. A sealed vessel with an impermeable membrane at the top is installed on an edge support located in the center of the vessel weight.

Due to pressure difference on both sides of the membrane, the working fluid moves inside the ring to the chamber with low pressure. The ring rotates backwards until the moment of force acting on the membrane counterbalances the gravity force of weight. Pressure difference unit is ring rotation angle. The main advantages of ring-balance and differential manometers are: high sensitivity, rotation angle independence of working fluid density, reading independence of ambient temperature. Upper-range measurement value is 400 to $2{,}5\times10^4$ Pa; accuracy - 1,0 and 1,5% of a scale limit. Float-type, bell-type and ring-balance manometers, either indicating or recording, can be supplied with flowmeters, control devices, indicators, as well as, with the devices for uniform pneumatic or electric distant signal receiving.



а) *б)*

Fig. 2.16. Hydrostatic differential manometer types: a) bell-type manometer; b) ring-balance manometer; 1 - bell; 2 - membrane; 3 - supports; 4 – weights

***Elastic element gauges** – **Elastic element gauge** – is based on a sensing element deformation which flexes elastically under the effect of a pressure difference across the element;*

Elastic element gauges use the deformation of a sensing element or force developed under the effect of the measured pressure. Proportional deformation or force is converted into readings or corresponding outlet signal changes. Elastic element gauge measurement ranges from 10 to $2{,}5 \cdot 10^9$ Pa.

Most manometers, as well as, differential manometers use elastic sensing element transforming pressure values in proportion to working point movement. (Fig. 2.17).

Based on sensing element type and pressure difference, the following manometers types are distinguished: spring-type, bellows, and membrane-type manometers.

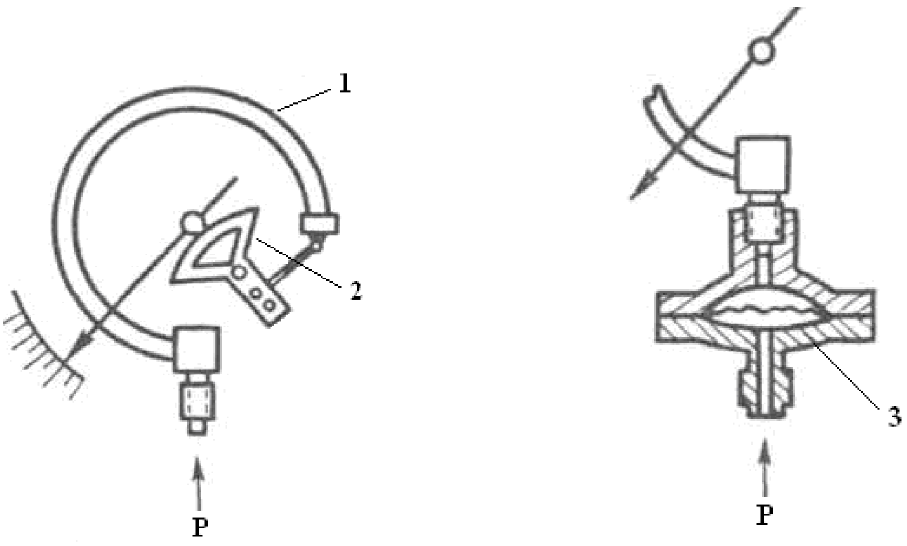
***Spring-type pressure gauges** - elastic element gauge with a tubular-spring as a sensing element;*

***Bellows manometers** - elastic element gauge with a bellow as a sensing element;*

***Membrane-type manometers** - elastic element gauge with a membrane or bellows as a sensing element;*

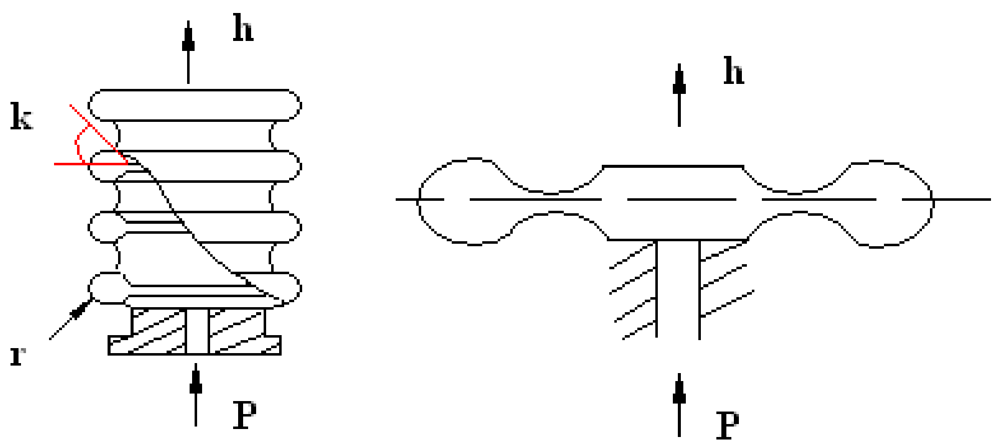
***Manometers with flexible membrane** - elastic element gage where measured pressure is sensed by flexible membrane and transformed into a* *counterbalancing force through an additional device* [11].

The most commonly-used elastic sensing elements are: tubular-spring, (Fig.2.17a), bellow (Fig.2.18, a), bellows (Fig.2.18, b) and membranes with a fixed center.



а) *б*)

Fig.2.17. Elastic element gauges: a) tubular-spring indicating manometer; b) manometer with a sealed chamber and membrane pressure separator; 1 – spring; 2 –driving gear; 3 –chamber



а) *б*)

Fig. 2.18. Elastic sensing element:
a) bellow; b) bellows

Hollow single-coil springs (Fig.2.17, a) have elliptic or flat-oval cross-section. One end of the spring, connected to the pressure to be sensed, is fixed to the holder while the second one can move. Due to the difference between internal measured pressure and ambient pressure, the spring deflects. Brass and bronze springs are used for pressures up to 5 MPa, while springs of alloyed steel and nickel alloy are intended to sense higher pressures.

Bellow (Fig. 2.18, a) is a thin-wall tube with cross circular spiral grooves on the sidewall. Bellow hardness depends on the material, outer and inner diameters, wall manufacture thickness, rounded groove (corrugated) radius r, compaction angle ***k*** and groove number.

Membrane sensing elements are considered to be the most various in design. Corrugated diaphragms and bellows (Fig. 2.18,b) are used for statistic improvement. Membrane profiles can be trapezoid, sinusoidal, and zig-zag. The most commonly-used bellows are welded or soldered along the outer edge of the membrane. Hardness of bellows is twice less then the hardness of which membrane. Membrane blocks, consisting of two or more bellows, are used in differential manometers.

During pressure measuring instrument performance, elastic deformation zone reduces due to ambient temperature increase. Therefore, primarily devices are installed from hot facilities. Due to periodic load and pressure effects the elastic characteristics of the sensing elements reduce and plastic deformation develops. These two factors should be considered during pressure instrument operation as they have negative influence on sensing element reliability.

Single-coil spring manometer. Nowadays, both indicating and recording single-coil spring manometers (MT, MP) are manufactured now (Fig. 2.19). In these devices measured pressure is continuously converted in the moving free spring end which, in its turn, is connected to indicating, recording and warning devices, in primarily devices or to pressure transducers (distant transmitting signal in secondary devices).

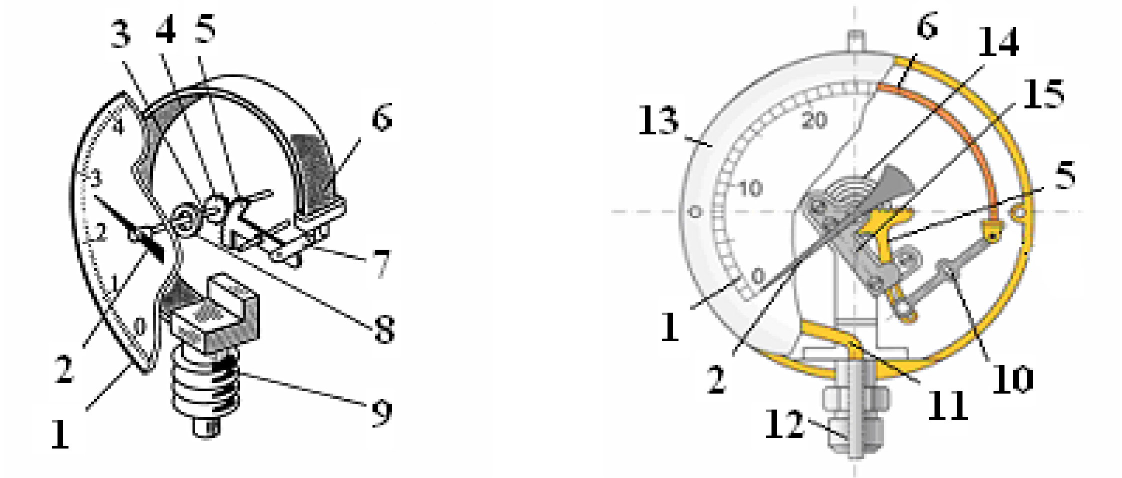


Fig.2.19. Single-coil spring manometer:
1 – scale; 2 – needle; 3 –axle; 4 – gear; 5 – sector; 6 – tube; 7 – haul; 8 – fiber spring; 9 – nipple; 10 – carrier; 11 – holder; 12 – nipple; 13 –body; 14 – thread; 15 –plate

The main part of a single-coil spring manometer (Fig. 2.19) is a hollow bent tube (***6)***, with a stationary fixed end to the nipple (9), securing the manometer to the gas pipeline. The second end of a tube is welded and joined to the haul (***7)***. Gas pressure is transmitted through the nipple (***9)*** to the tube (**6)**, where free end drives the sector (***5),*** gear (***4)*** and axle (***3)*** through the haul. Fiber spring (***8)*** secures gear and sector providing smooth needle movement. A shut of valve, to replace or remove the manometer, is installed in front of it. Operation life of manometers goes through registration testing every year. Working pressure measured by the manometer rangs from 1/3 to 2/3.

Recording multicoil spring manometer (Fig. 2.20.) is an oblate circle 30 mm in diameter with six coils. Due to the significant length of a spring, its free end can move up to 15 mm, while in a single-coil spring manometer – to 5...7 mm. Spring twist angle is 50…60º. Such a design includes simple levers and automatic distant record readings. Connecting the manometer to the medium (fluid) being measured, the free end of the spring (***1)*** of the lever (***2)*** turns the axle (***3),*** that is movement of levers (***4)*** and ***(7)*** and haul (***5)*** will be transmitted to the axle (***6)*** where a pivot (***8)*** is fixed and connected to the needle (***9)***.

Pressure change and spring movement through the lever are transferred to an indicating needle with a writing point. Dial card is rotated by the clock mechanism.

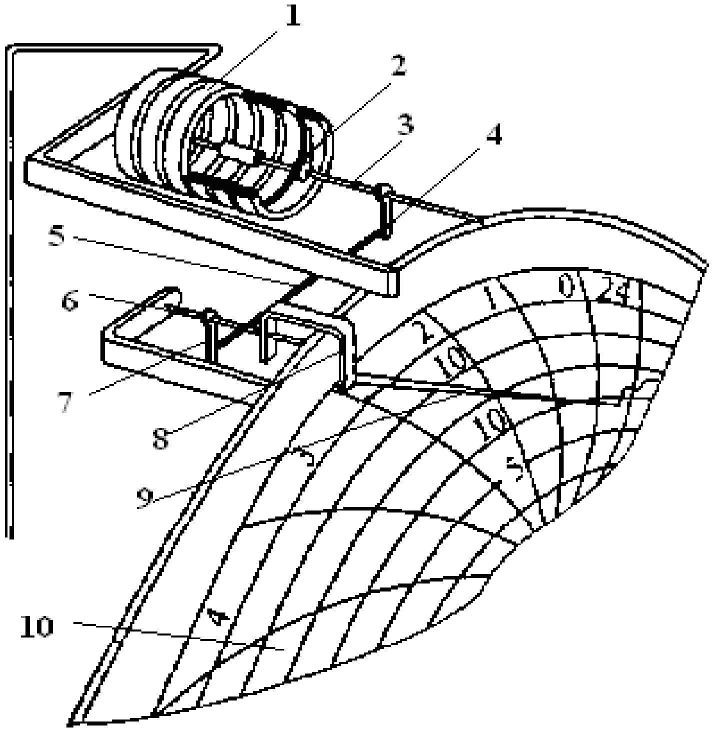


Fig. 2.20. Recording multicoil spring manometer:
1 – multicoil spring; 2, 4, 7 – levers; 3, 6 – axles; 5 – haul; 8 – pivot; 9 – needle with a writing point; 10 – dial card

Bellows differential manometers Bellows differential manometers measure continuous fluid flow rate. Such manometers are based on the counterbalance principal of differential pressure, deformation force of two bellows torsion springs and cylindrical spiral springs (Fig. 2.21). Springs are detachable and are installed according to the differential pressure being measured. The main parts of differential manometers are bellows block and indicating sector.

Positive bellows are attached to the pulse tube sensing the pressure before the diaphragm, while negative bellows sense the pressure after the diaphragm.

Bellows block includes connected bellows (***2)*** and (***6)***, filled with a liquid that is 67% water and 33% glycerin. Bellows are connected by a rod (***8)***. The bellows (***2)*** sense the pressure before the diaphragm while the bellows (***6)*** – after the diaphragm.

Under high pressure compressed liquid moves from the left to the right bellows through the throttle (***5).*** The rod (***8)***, fixed to bellows bottoms, moves to the right through the lever (***3),*** rotating the axle (***4)*** connected to the registering and indicating device needle. The throttle (***5)*** controls fluid flow and decreases pressure pulsation influence on instrument performance.

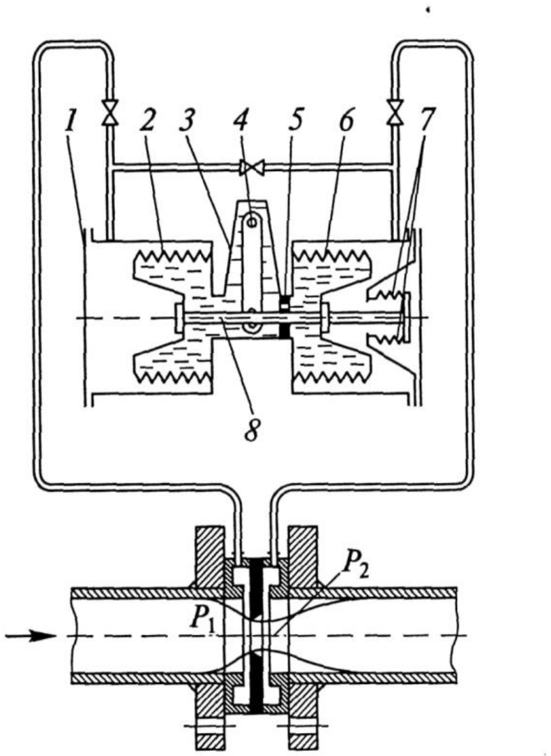


Fig. 2.21. Basic diagram of bellows differential manometer:
1 – bellows block; 2 – positive bellows; 3 – lever; 4 – axle; 5 – throttle; 6 – negative bellows; 7 – detachable springs; 8 – rod

The most commonly-used types of bellows differential manometers are DSP-160-M1B, the characteristics of which are given in the table 2.3.

Table 2.3.

Characteristics of DSP-160-M1 bellows differential manometer

Characteristics	Values
Maximum permissible working excess pressure, kgf/cm^2	63; 160; 250; 320
Maximum nominal differential pressure, kgf/cm^2	0,063; 0,1; 0,16; 0,25; 0,4; 0,63; 1; 1,6; 2,5 – на избыточное давление до 63 и 160 кгс/см^2; 0,4; 0,63; 1,6; 2,5; 4; 6,3 – на избыточное давление до 250 и 320 кгс/см^2
Accuracy class	1; 1,5
Ambient temperature, °C	от –40 до +70
Relative humidity, %	до 80

Manufactured according to requirements	ТУ 25-7310.0063–87
Russian Production Classification Code	42 1253
Dimensions, mm	195×153×136
Weight, kg (not more)	16

Membrane manometers. Membrane sensing elements, mostly manufactured as bellows, are used to measure head and depression pressure. Measured pressure enters bellows chamber, where center relocation is transformed to proportional rotation angle of an indicating needle.

Membrane sensing elements are used in pressure transducers either with direct measured value conversion or with statistic counterbalancing. Thus, bellows chamber as a sensing element is used in electric membrane manometers with magnetic flow compensation and in absolute pressure manometers.

Piston manometers. В этих приборах измеряемое давление действует через рабочую жидкость на поршень манометра (рис. 2.22).

Piston manometer *– counterbalances the measured pressure with the pressure created by receptacle piston weight and loads with fluid friction force consideration* [8, 11].

The measured pressure effecting the manometer piston through the working fluid is counterbalanced by piston weight and dead-weight calibration testers (Fig. 2.22). The most common piston manometers are open-spaced ones. The chamber below the piston is filled with specific oil that enters the gap and lubricates the interacting surfaces. When measuring the pressure, the piston is rotated manually or by electric motor to decrease friction between the cylinder and the piston. Altering the load weight and piston cross-section, manometer measurement limits can be changed within the range of 2500 Pa to 2500 MPa.

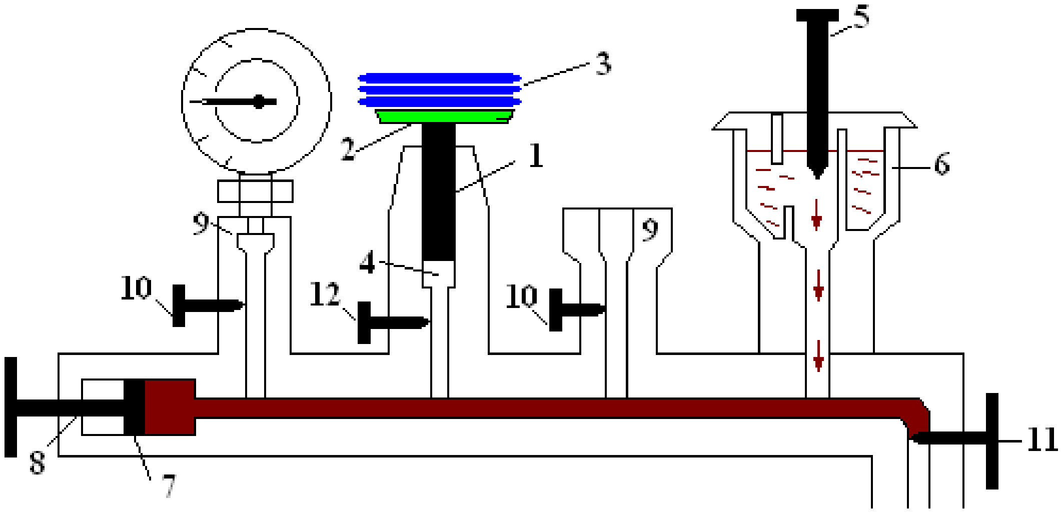


Fig.2.22. MP-60 Piston manometer

MP-60 piston manometer has a range of 6 MPa. A piston ***(1)*** with a load (***3)*** plate (***2)*** moves inside the cylinder (***4)***. *P*iston couple is adjusted so that the gap between the piston (***1)*** and the cylinder (***4)*** does not exceed 0,01 mm. When the gap does not exceed 0,01 mm, piston-lowering speed caused by working fluid leakage does not exceed 1 mm/min. For identical gap between the cylinder and piston, the latter rotates clockwise during pressure measurement. When the measurement range is 6 MPa or higher, the piston is rotated manually. When the measurement range is 0,06 and 0,25 MPa, the piston is rotated with electric motor.

The inner chamber of manometer piston is filled with working fluid (kerosene, castor or transformer oil). The chamber is filled with fluid through hole at the bottom of the chamber (***6)*** when the valve is open (***5)***; *the* fluid is pumped into the manometer through the piston (***7)*** of a coil press ***(8)***. During measurement, the press leaves the piston with a load ***(1)*** to the height set by the indicator needle. Tested manometers are attached to the risers (***9)*** with *shut* valves (***10).*** The valve (***11)*** is used to drain fluid from the piston manometer.

These devices are distinguished by high accuracy and sustained readings; the accuracy is from 0,02 to 0,2% of the upper-range value. To measure low excess pressures, depression, absolute and atmospheric pressures, the manometers with a special geometry design are applied. Piston manometers are used to test other manometers types or for laboratory measurements.

The most commonly-used piston manometers:

- MPA-15 standard piston manometer (Fig. 2.23)
- SRb 5000 Piston manometer (Fig.2.24)

Fig. 2.23. MPA-15 Standard piston manometer

Fig. 2.24 SRb 5000 Piston manometer

MPA-15 is intended to test and calibrate absolute and excess pressure manometers, barometers, pressure gauges and other pressure measuring instruments. MPA-15 is a piston manometer of accuracy class one. Measurement error is 0,01%. MPA-15 characteristics are given in the Table 2.4.

Table 2.4

МПА-15 Characteristics

Characteristic	Value
Measurement range, Pa	$0 \ldots 4 \times 10^5$
Maximum error range: $0 \ldots 2\times 10^4$ Pa $2\times10^4 \ldots 1{,}33\times10^5$ Pa $1{,}33\times10^5 \ldots 4\times10^5$ Pa	 ±6,65 Pa ±13,3 Pa ±0,01% of measured value
Dimensions, mm	390×280×630
Weight, kg	30
Alternating-current supply	220 V, 50 Hz

Distant reading transmission manometers. Distant reading transmission manometers are based on the alteration of medium electrical properties (conductor electrical resistance, capacity, electrical charge occurrence on the mineral crystal surface, etc.). due to measured pressure effect. Manganine resistance-pressure gauges, piezoelectric pressure gauges based on quartz crystal, tourmaline and Seignette salt application, capacity and ionization gauges are such manometers. According to «GOST 8.271-77 GSI. Pressure Measuring Instruments. Terms and Definitions» the following terms are introduced.

Electric pressure gauge *– based on dependence of pressure transducer electric properties on the pressure being measured.*

Piezoelectric pressure gauge *– electric pressure gage which operating principle is based on the piezoelectric element charge dependence on the pressure being measured.*

Cold-cathode ionization gauge *– ionization gage, based on the dependence of electric charge current in magnetic field on the pressure being measured.*

Resistance pressure gauge *– electric pressure gage, based on the dependence of sensing element electric resistance on the pressure being measured.*

Radioactive ionization manometer *- ionization gage, based on gas ionization due to radioisotope source radiation.*

Thermal gauge *– is based on the ability of a dilute gas to conduct heat decreased with pressure*

Thermocouple manometer *– thermal gage, based on the dependence of thermocouple thermo-EMF on the pressure being measured.*

Viscous gauge *– is based on the dependence of dilute gas viscosity, defined by a solid body movement in it, on the pressure being measured.*

Electric manometers are based on the dependence of substance electric resistance on the pressure being measured. They are called *strain gauges* manufactured from semiconductors of constantan, platinum, copper and nickel alloys. They are used as pressure measuring instrument sensing elements, connected to a device membrane or spring, which is deflected due to the pressure being measured (Fig. 2.25). Sensing elements can be manufactured with filmed semiconducting connections.

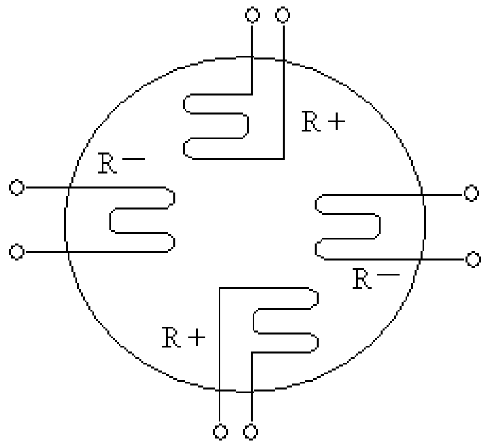


Fig. 2.25. Resistance strain gauge arrangement on the membrane surface

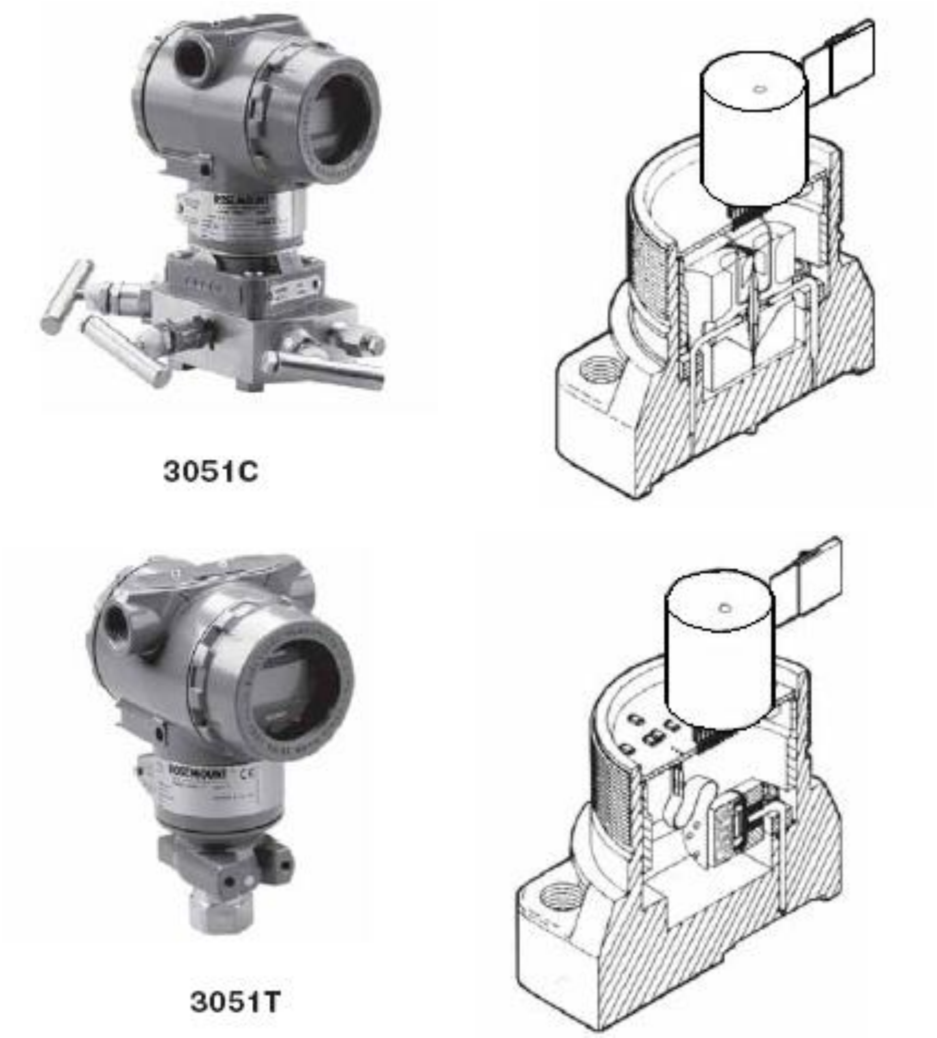
In comparison to metallic strain gauges, semiconductor strain gauges are more sensitive, smaller in size and lighter in weight.

Manganine strain gauges are used to measure high pressures (up to 1000 MMPa). The disadvantage of this device is reading dependence on the temperature of the fluid being measured. Strain transducers and temperature compensators are introduced into the instrument measuring circuit.

Operating principle of other electric pressure measuring instruments is based on the piezoelectric effect. According to this effect, the electrostatic charges occur on the faces of quartz crystals when they are deflected along the axis perpendicularly to the faces. Crystals are two plates connected to the membrane effected by the pressure being measured. Piezoelectric pressure gauges are intended to measure pressure up to 100 MPa and are widely applied in high frequency cyclical pressure change. The sensitivity of such transducers can be improved by the increase of quartz plate number, enlargement of membrane active area and extension of the plate.

The disadvantage of piezoelectric pressure gauge is static pressure low accuracy due to electric charge loss, at the same time its advantage is low temperature error.

For example, electric manometers manufactured by «Metran» Company (Chelyabinsk) and with Emerson Process Management. There are two types: Fig. 2.26, a - pressure transducer 3051C with a sensory module; Fig. 2.26, b – piezoresistive pressure transducer 3051T.



а)

б)

Fig. 2.26. Electric pressure gauges:
a)transducer 3051S; b) transducer 3051T

The transducers are intended to measure differential pressure, fluid, steam, gas excess and absolute pressures with upper-range value from 0,025 to 27580 kPa for 3051S model and from 2,07 to 68950 kPa for 3051T model.

Two types of sensory module units - capacity and piezoresistivity are used in the 3051 transducers (Fig. 2.27). Capacity unit is used for differential and excess pressure measurement, while piezoresistivity unit – absolute and excess pressures.

The membranes sensing the pressure being measured are placed on a horizontal plane and called coplanar unit.

The measured pressure in capacity transducers is transferred through the separating membranes (a membrane in excess pressure manometer) and filling fluid to the measuring membrane positioned between the condensor plates (Fig.2.28). The capacity of the unit, formed by a sensory membrane and condensor plates, is changed due to membrane deflection caused by measured pressure effect. Generated electric signal is converted into digital and transferred to the microcontroller.

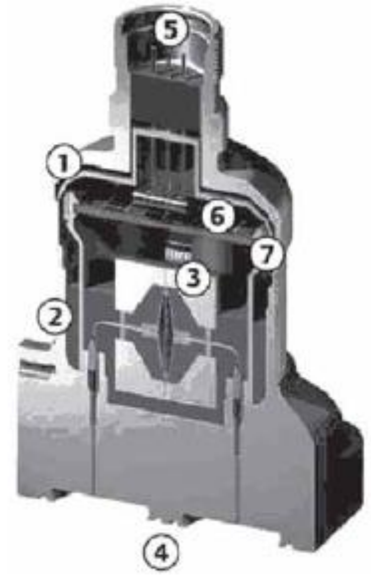


Fig. 2.27. Pressure transducer sensory module 3051S:
1,2 – unit-welded body; 3 – capacity unit; 4 –sensing separating membranes (of different materials including alloys meant for operating in aggressive media; 5 – plug and socket joint (outlet signals from 4 to 20 мА); 6,7 – electric board

The measured pressure in the piezoresistive pressure transducer is transferred through a separating membrane and filling fluid to the measuring membrane the deflection of which causes the resistance change in Winston pivot/bridge circuit. Error signal is converted into digital for microcontroller processing.

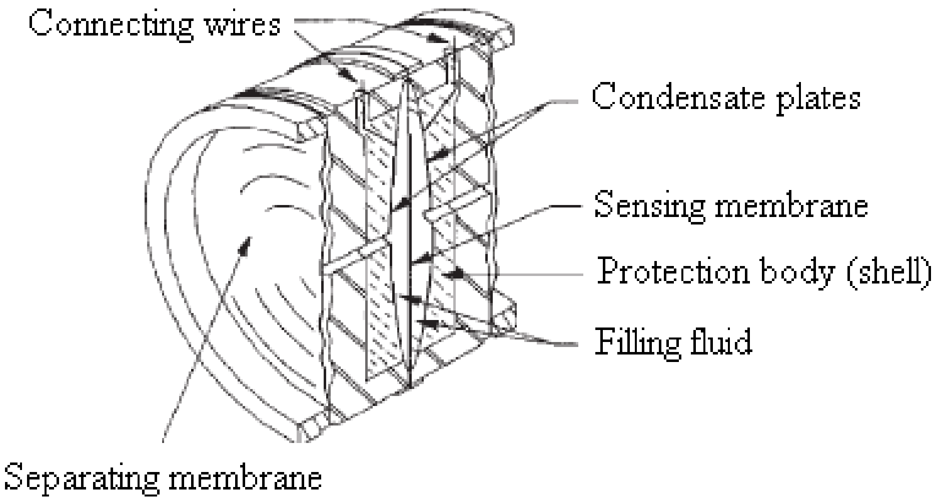


Fig. 2.28. Capacity transducer

Pressure transducer sensory module 3051 is fitted by a thermometer used for correction and record of the temperature effects on the outlet signal under operating conditions.

2.2.2. Temperature measuring instrument classification

Temperature is a principle parameter which defines both technological process and fluid properties. The basic unit of temperature in the International System of Units (SI) is the kelvin (K). Kelvin scale is defined by absolute zero as a reference point. Celsius scale (°C) is frequently applied in technological measurements.

Different primary transducers distinguished by intermediate signal temperature conversion technique are used for temperature measurements. These devices constitute the most widely-spread group of instruments intended for technological parameter monitoring. Temperature monitoring techniques are divided into mechanical, thermal, electric, radioactive and etc.

All temperature measuring instruments are divided into two groups. The instruments of the first group measure the temperature by the direct contact with the substance being measured. The second group instruments measure the temperature by indirect measurement methods (Fig. 2.29).

Contact Thermometers. Expansion thermometers.

Expansion thermometers *are based on the thermal expansion of liquid (**liquid thermometers** – Fig. 2.30.) or solid body (**dilatometric and bimetallic thermometers** – Fig. 2.31).*

Liquid-in-glass thermometers are the most commonly-used. As the working liquid (mercury, toluene, ethanol and etc.) gets warmer, it expands up in a capillary. Thus, the temperature measured by liquid-in-glass thermometer is converted into a linear expansion rate. Scale is on the capillary glass surface or fixed on the external scale surface.

The thermometer sensitivity depends on the difference of thermometer liquid volume expansion and glass coefficients, as well as, measuring capacity and capillary diameter coefficients. The thermometer sensitivity usually ranges from 0,4 to 5 mm/°C (from 100 to 200 mm/°C in some specific thermometers).

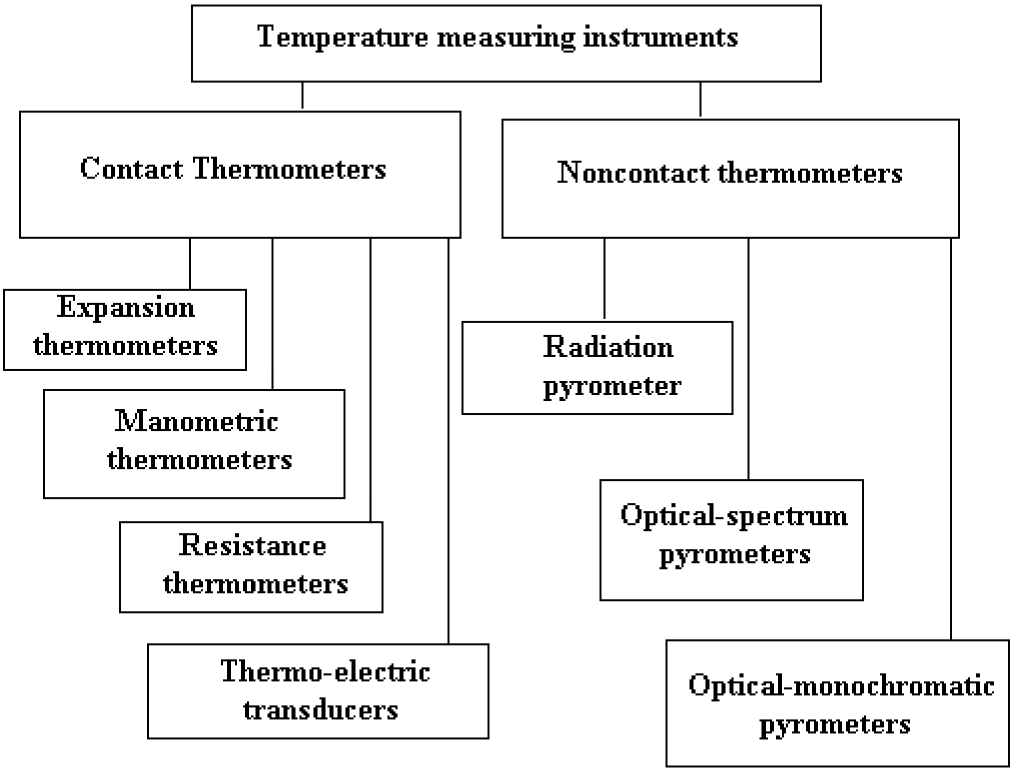
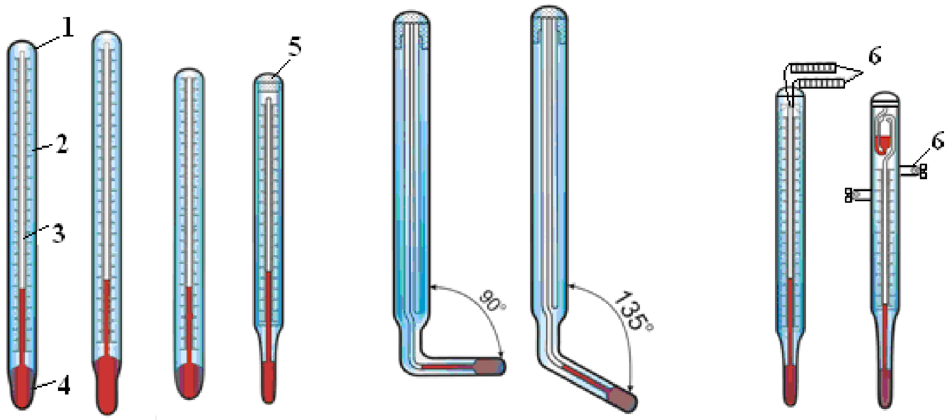
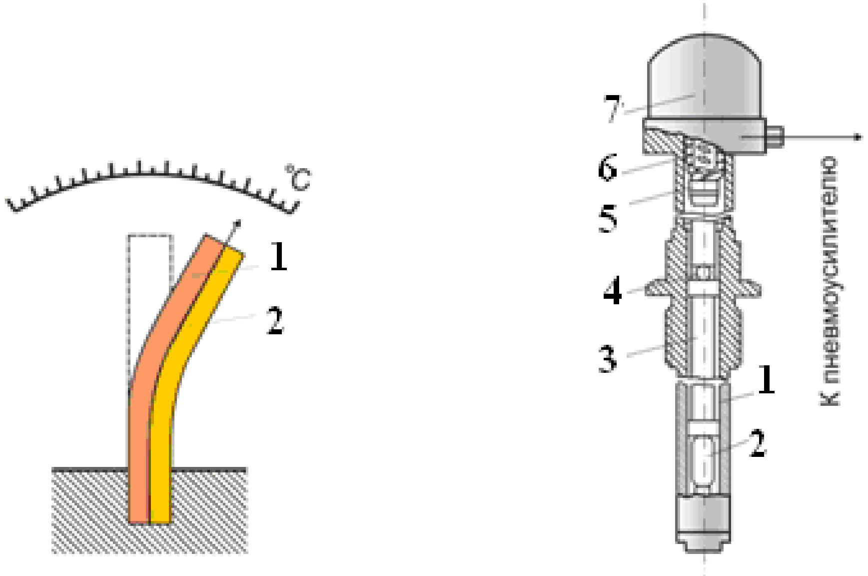


Fig. 2.29. Temperature measuring instrument classification



а) *б)* *в)*

Fig. 2.30. Expansion liquid-in-glass thermometers:
a) direct; b)angle; c) contact; 1 – body; 2- scale; 3 – capillary; 4 – bulb; 5 – plug; 6 - contacts



а)　　　　　　　　　　　　*б*)

Fig. 2.31. Expansion liquid-in-metal thermometers:
a) bimetallic thermometer (1 – brass; 2 – invar); b) dilatometric thermometer (1 – body; 2 –stem; 3 – tube; 4 – bulb; 5 – pusher; 6 – swing; 7 – transformer)

Dilatometric and ***bimetallic thermometer*** operating principle is based on solid body linear size change due to temperature variation. *Dilatometric thermometer* design is defined by measured temperature transformation into the absolute elongation difference of two stems made from the materials characterized by significantly different linear expansion thermal coefficients $\boldsymbol{\beta}$:

$$\beta_{t_1,t_2} = \frac{l_{t_1} - l_{t_2}}{l_0\left(t_2 - t_1\right)},\ \frac{1}{\text{ãðàä}}, \tag{2.45}$$

where, $\mathbf{l_0}$, $\mathbf{l_{t1}}$, $\mathbf{l_{t2}}$ – body linear size at 0 °C, temperatures $\mathbf{t_1}$ and $\mathbf{t_2}$ correspondingly..

As linear expansion coefficient variation value Δβ is insignificant, dilatometric thermometers are applied as different thermal relays in signal and temperature control devices.

Bimetallic thermometers are based on the deflection of a bimetallic tape due to temperature change. Bimetallic tapes are usually bent in form of flat or helical spiral. The first end of the spiral is fixed, while the second one is on the needle axis. Spiral rotation angle equals its twist angle which is proportional to temperature change. Bimetallic thermometer fractionary accuracy is from 1 to 1,5 %.

Thermometers are installed in the industrial pipelines in two ways: when a sensing element is in direct contact with the medium being measured and when a sensing element is isolated by the protective casing. In spite of the fact that the first method is favourable for heat transmission, the thermometers may be mechanically damaged and the places, where the thermometers are installed, should be sealed. Though the second method provides thermometer damage protection, it increases thermometer persistence. As a rule, the second method is applied in practice.

To decrease heat resistance which can occur when the protective casing is used, annular gap between the thermometer and inner casing wall is filled with heat-conducting material – engine oil (for thermometers with the scale up to +200 °C), copper and steel filings (for thermometers with the scale up to +500 ºC). The part of the thermometer projected from the measured medium should be short where possible and heat-insulated.

Technological glass thermometer casings can be of two types:

- *Casings with the protective tube perforated for nonaggressive media when the conventional pressure of the measured medium equals the atmosphere pressure;*
- *Casings with a sealed protective tube for measuring chamber and submersible thermometer part isolation from the medium being measured when the conventional medium pressure is up to 6,4 and 32,0 MPa.*

Manometric thermometer. is a temperature measuring instrument which is based on one of the following three principles: thermal liquid expansion, gas pressure temperature dependence and liquid saturated vapor pressure temperature dependence.

They are based on the temperature and gas pressure dependence as well as dependence of temperature and fluid volume in a sealed thermal system. Manometric thermometers are divided into three main types

- *Liquid thermometer where the whole measuring system (thermal phial, manometer and capillary) is filled with fluid;*
- *Vapor-pressure thermometer where the thermal phial is partially filled with low boiling-point fluid and its saturated vapor, while the capillary and manometers are filled with fluid saturated vapor or carrier fluid;*
- *Gas thermometer where the whole measuring system is filled with inert gas.*

Manometric thermometers usually consist of thermal phial, capillary, tubular spring with a drive lead, gear quadrant, and a needle. The whole system is filled with working fluid. When the thermal phial (Fig. 2.32) fitted in a measuring temperature zone is heated, working fluid pressure increases within the sealed system. Pressure increase is sensed by a manometer spring effecting the instrument needle through the driving gear.

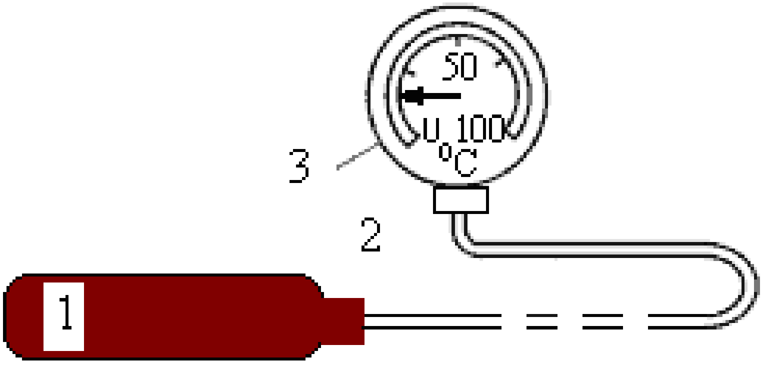


Fig. 2.32. Manometric thermometer:
1 – thermal phial; 2 – capillary; 3 - manometer

Gas manometric thermometers are based on the dependence of temperature and gas pressure in a sealed thermal system. Methyl alcohol, xylene, toluene, mercury and other are used as a manometer liquid in *liquid manometric thermometers.*

Vapor-pressure thermometers are based on low-boiling liquid saturated vapor tension and temperature dependence. As these dependences are nonlinear for working fluids (methyl chloride, ethylic ether, ethyl chloride, acetone and etc.), the thermometer scales are not uniform. However, these thermometers are more sensitive than gas and liquid ones.

Possible manometric thermometer designs are shown below (Fig. 2.33., Fig. 2.34., 2.35. and Fig. 2.36.).

The advantages of all manometric thermometers are their design and application simplicity (instrument scale is almost uniform), the possibility of remote temperature measurement and automatic readings record, and the absence of electrical parts that increases the risk factor.

The disadvantages of manometric thermometers are relatively high persistence, significant thermal phial size and low accuracy (accuracy class 1,5; 2,5; 4,0 and rarely 1,0).

When installing the manometric thermometer in industrial pipelines, thermometer thermal phial must be completely immersed in the medium (fluid) being measured. Thermal phial position can be different (horizontal, vertical, inclined) depending on the conditions. Like expansion thermometers, manometric thermometer thermal phial can be installed in a protective casing depending on the pressure and chemical properties of the medium (fluid) being measured. To increase heat conduction the space between the inner case wall and thermal phial is filled with grits or fluid, the boiling-point of which is higher than the thermometer upper-range value. The capillary connecting manometric thermometer thermal phial and secondary instrument must be installed in places where the temperature is constant. It should be isolated from hot or cold surfaces by air space (gap) or heat-insulating material. When installing manometric thermometer capillary, it should not be bent because it can lead to the plugging of the capillary inner opening, the diameter of which is 0,2 or 0,36 mm. Capillary bending radius must be more than 60 mm. The whole capillary must be protected from mechanical damages of the perforated angle or spiral wrap hose.

Resistance thermometers. *Resistance thermometers (resistive temperature transducer) and thermal electric transducer (thermocouple)* are considered to be temperature transducers. *Resistance thermometers* exploit the

a) *b*)

Fig. 2.33. Resistance thermometers:
a) TM2030Sg-1 with gas filler; b) manometric vapor-pressure indicating and signaling/warning TKP-160Sg-M2 thermometer

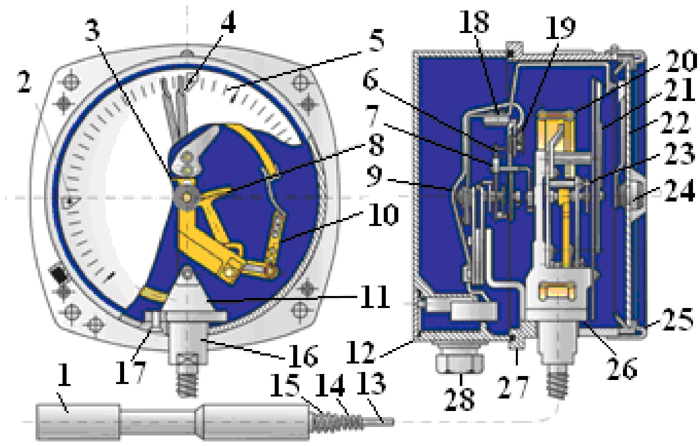


Fig. 2.34. Manometric thermal system: 1 – thermal phial; 2, 4 – signaling /warning limit indicators; 3 – fiber; 5 –scale; 6, 7 – driven leads; 8 –sector; 9 – drive lead; 10 – haul; 11 – mechanism; 12 – case; 13 – capillary; 14, 15 – protective casings; 16 – holder; 17 – holder screw; 18, 19 – fixed limit contacts; 20 – manometric spring; 21 – needle; 22 – flag; 23 – pinion; 24 – setting mechanism; 25 – shell; 26 – body; 27 – electric contact; 28 – gland

predictable change in electrical resistance of some conductors and semi-conductors materials with changing temperature. Resistance thermometers can be *metal* and *semi-conductor*.

Resistance in *metal thermometers* increases almost in direct proportion to temperature rise, while in semi-conductor thermometers it decreases. Resistance thermometers are shown in Fig. 2.37, 2.38., 2.39, 2.40.

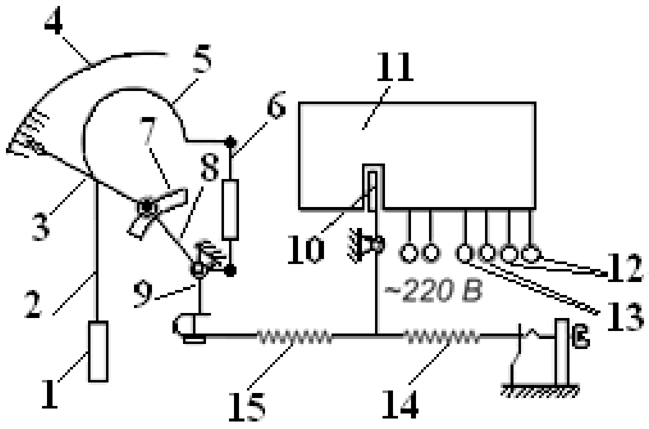


Fig. 2.35. Manometric thermometer with electric signal output: 1 – thermal phial; 2 – capillary; 3 – needle; 4 – scale; 5 – manometric spring; 6 – haul; 7 – pinion; 8 – sector; 9 – lever; 10 – flag; 11 – mechanoelectrical transducer; 12 –from 0 up to 100 mWatt; 13 – output from 0 to 5 mA; 14 – zero adjuster spring; 15 – spring

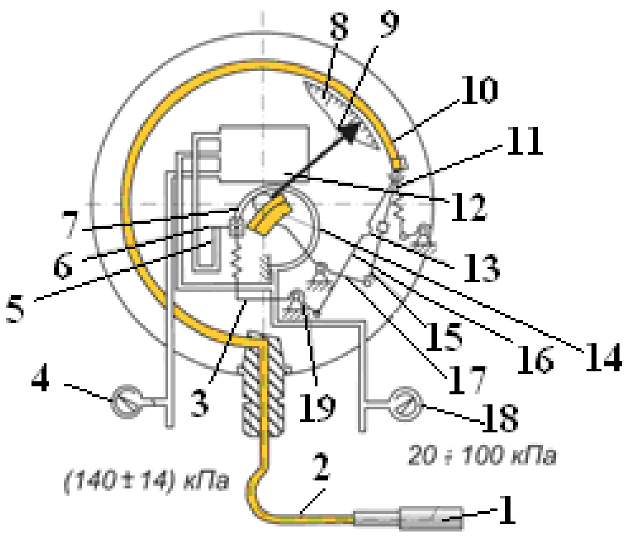


Fig. 2.36. Manometric thermometer with pneumatic output signal: 1 – thermal phial; 2 – capillary; 3 – lever motion; 4/ 18 – manometers; 5 – nozzle; 6 – choke; 7 – feedback spring; 8 – dial; 9 – needle; 10 – manometric spring; 11 – spring; 12 – pneumatic relay; 13 – thermal bimetal 4/14 – tripo-sector mechanism; 15/16 – hauls; 17/19 – leads

Resistance thermometers (resistive temperature transducer) and thermal electric transducer (thermocouple) are considered to be temperature transducers. *Resistance thermometers* exploit the predictable change in electrical resistance of some conductors and semi-conductors materials with changing temperature. Resistance thermometers can be *metal* and *semi-conductor*.

Resistance in *metal thermometers* increases almost in direct proportion to temperature rise, while in semi-conductor thermometers it decreases. Resistance thermometers are shown in Fig. 2.37, 2.38., 2.39, 2.40.

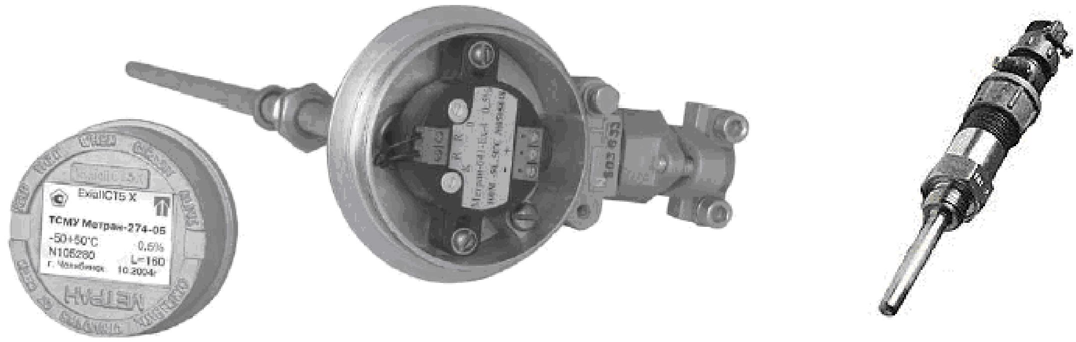


Fig. 2.37. Resistance thermometers

Fig. 2.38. Universal electric resistance thermometer 2TYE 111

Fig. 2.39. Portable resistance thermometer

Despite the high sensitivity of semi-conductor thermometer in comparison with the thin-wire resistance one, the former is rarely applied in industrial practice. It is explained by the significant difference in their calibrating characteristics that makes difficult their interchangeability.

Fine metal resistance thermometers, the most widely spread ones, are usually manufactured as a wire winding (about 0,05 mm in diameter) on a special insulator - material frame. Wire winding is usually called *sensing element* of a resistance thermometer. To protect it from possible mechanical damages and medium (fluid) effect the sensing element is embedded into a special protection sleeve or sheath (Fig. 2.41, 2.42).

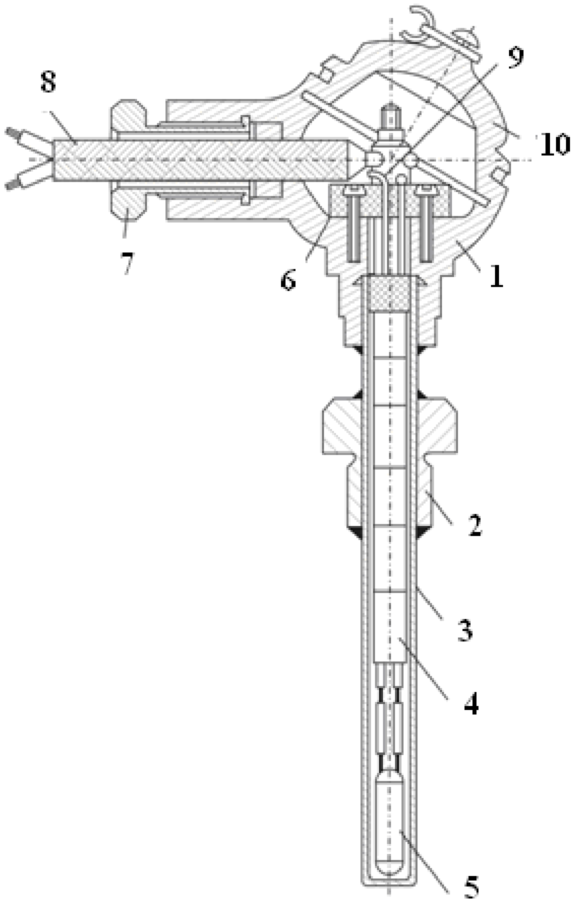


Fig. 2.40. Resistance thermometer elements: 1 – head body; 2 – nipple; 3 – sheath; 4 – porcelain beads; 5 – sensing element; 6 – connector block; 7 – gland entry; 8 – mounting cable; 9 – wires; 10 – cap

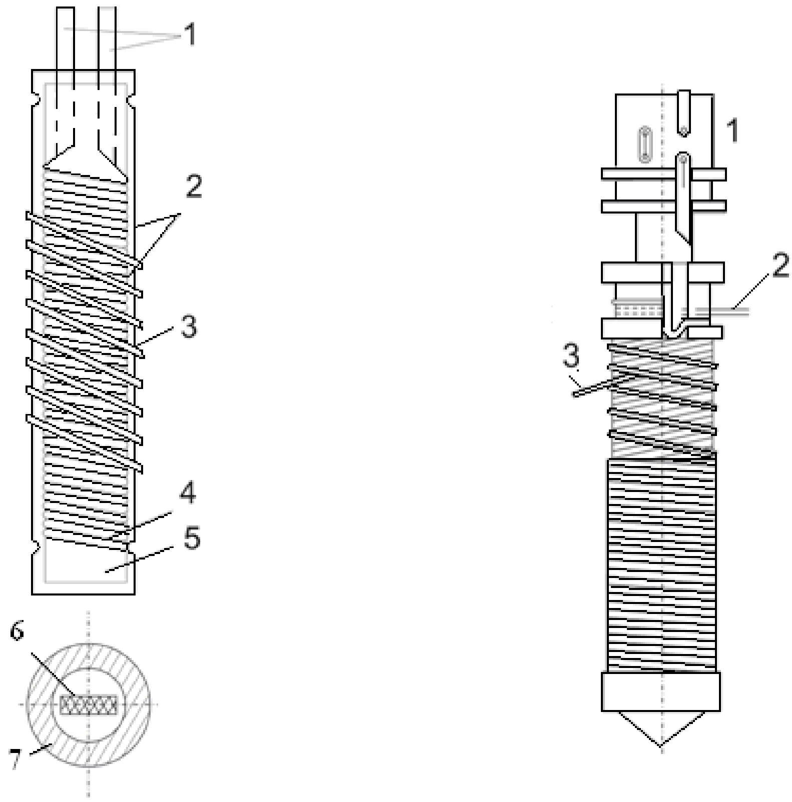
When measuring temperature, resistance thermometer is immersed into the medium (fluid) which temperature should be measured. If the dependence of thermometer resistance and temperature is known, the medium (fluid) temperature can be defined by thermometer resistance change.

Sensing element – is thermal transducer element which senses and converts heat energy into another energy so as to measure temperature [12].

Sensing elements are available in a number of forms. The most widely-spread elements are made in the form of cylinder, pivot, washer, and bead. To manufacture sensing element in resistance metal thermometer, fine metals are applied with the following requirements:

- *metal should not oxidize or undergo chemical reaction with the medium (fluid) being measured;*

- *metal electric resistance temperature coefficient α should be sufficiently large and constant;*
- *specific metal resistance should be sufficiently great.*



a)	*б*)

Fig. 2.41. Resistance thermometer sensing elements: a) platinum (1 – leads; 2 – protective plates; 3 – film; 4 – platinum wire; 5 – thread platinum; 6 – sensing element; 7 – sheath); б) copper (1 – frame; 2 – initial winding; 3 – winding end)

Fig. 2.42. Protection sleeves

Platinum, copper, nickel, and iron best of all meet these requirements. For example, the following types of resistance thermometers are distinguished: platinum resistance thermometer (PRT), copper resistance thermometer (CRT), and nickel resistance thermometer (NRT).

Resistance thermometers are manufactured with nominal static conversion characteristics (NSC) and resistance tolerance at 0 ºC (***R_0***) of nominal value according to ***GOST 6651-94***.

Depending on nominal value ***R_0*** and nominal resistance ratio ***W_{100}*** (i.e. thermometer resistance at 100 ºC and thermometer resistance at 0 ºC ratio), the arbitrary nominal static conversion characteristics should correspond to the following values given (Table 2.5.)

Table. 2.5.

Resistance thermometer characteristics according to nominal resistance value and nominal static conversion characteristics

<table>
<tr><th rowspan="2">Type</th><th rowspan="2">Nominal resistance value at 0°C, , Ohm</th><th colspan="3">Arbitrary nominal static conversion characteristics</th></tr>
<tr><th>CIS</th><th colspan="2">International (SI)</th></tr>
<tr><td rowspan="6">Platinum (PRT)</td><td rowspan="2">1</td><td rowspan="2">1П</td><td>W_{100} = 1,3850</td><td>W_{100} = 1,39100</td></tr>
<tr><td>Pt 1</td><td>Pt′ 1</td></tr>
<tr><td>10</td><td>10П</td><td>Pt 10</td><td>Pt′ 10</td></tr>
<tr><td>50</td><td>50П</td><td>Pt 50</td><td>Pt′ 50</td></tr>
<tr><td>100</td><td>100П</td><td>Pt 100</td><td>Pt′ 100</td></tr>
<tr><td>500</td><td>500П</td><td>Pt 500</td><td>Pt′ 500</td></tr>
<tr><td rowspan="4">Copper (CRT)</td><td rowspan="2">10</td><td rowspan="2">10M</td><td>W_{100} = 1,4260</td><td>W_{100} = 1,4280</td></tr>
<tr><td>Cu 10</td><td>Cu′ 10</td></tr>
<tr><td>50</td><td>50M</td><td>Cu 50</td><td>Cu′ 50</td></tr>
<tr><td>100</td><td>100M</td><td>Cu 100</td><td>Cu′ 100</td></tr>
<tr><td>Nickel (NRT)</td><td>100</td><td>100H</td><td colspan="2">Ni 100</td></tr>
</table>

Based on the resistance tolerance limit regarding NSC, resistance thermometers are divided into three classes (Table 2.6.).

Advantages of metal resistance thermometers:

- *temperature high accuracy measurement;*
- *application of additional measuring instruments with standard scale intended for any temperature interval;*

- *central temperature control due to connection of several interchangeable resistance thermometers to a measuring instrument through a switch unit;*
- *computer application.*

Table 2.6.

Resistance thermometer tolerance classes

Resistance thermometer type	Resistance tolerance of nominal value at 0°C, %, for tolerance class		
	A	B	C
Platinum (PRT)	0,05	0,1	0,2
Copper (CRT)	0,05	0,1	0,2
Nickel (NRT)	–	–	0,24

The basic characteristics of resistance flowmeters are described in Table 2.7.

Disadvantages of resistance thermometer are: constant power supply and slow response (up to 10 min.).

In industrial application resistance thermometers are used with logo meters, automatic balanced bridges, and automatic compensation devices. It is important to outline the fact that these devices have a Celsius scale which correspond to specific calibrations of resistance thermometers and the set value of wire resistance, connecting the thermometer to measuring instruments.

When applying resistance thermometer, the characteristics and properties of medium (fluid) being measured and ambient environment should be considered. Platinum thermometer should immerse in 50…70 mm below the flow being measured, while in copper thermometer – in 25…30 mm.

When thermometer is installed horizontally or obliquely, the nipple of the thermometer head is placed downward. Surface resistance thermometer working units are tightly adjoined the whole measured surface. Contact surface should be dressed to metallic luster before the surface resistance thermometer is installed.

Таблица 2.7

Основные характеристики термометров сопротивления

Type	Characteristics/ range	Characteristic value
PRT	Temperature range, °C	from -260 to +850 (1100 – for single-manufactured unit)
	Tolerance class	A, B, C
	Resistance tolerance limit regarding NSC for tolerance classes, °C	

	A	±(0,15+0,002$\lvert\underset{\sim}{t}\rvert$) from -220 to +850°C
	B	±(0,3+0,005$\lvert\underset{\sim}{t}\rvert$) from -220 to +1100°C
	C	±(0,6+0,008$\lvert\underset{\sim}{t}\rvert$) from - 100 to +300°C; from 850 to 1100°C
CRT	Temperature range, °C	from –200 to +200
	Tolerance class	A, B, C
	Resistance tolerance limit regarding NSC for tolerance classes, °C	
	A	±(0,15+0,002$\lvert\underset{\sim}{t}\rvert$) from -50 to + 20°C
	B	±(0,25+0,0035$\lvert\underset{\sim}{t}\rvert$) from -200 to +200°C
	C	±(0,5+0,0065$\lvert\underset{\sim}{t}\rvert$) from -200 to +200°C
NRT	Temperature range, °C	from -60 to +180
	Tolerance class	C
	Resistance tolerance limit regarding NSC for tolerance classes, °C	
	C	±(0,3+0,0165$\lvert\underset{\sim}{t}\rvert$) from -60 to 0°C ±(0,3+0,008$\lvert\underset{\sim}{t}\rvert$) from 0 to +180°C

where $\underset{\sim}{t}$ *- measuring temperature value, °C.*

The characteristics and design geometry of T1002 sleeve resistance thermometer (range: from -200 to 550 550°C) intended for distant measurement of fluid temperature in pipelines, reservoirs and etc. are given below (Fig. 2.43, 2.44).

Transducer heat sensitive element is one or two measuring resistors fixed in measuring bush stem and connected to the head terminal block by internal wiring. The resistance varies linearly with temperature. Signal resistance is converted into the uniform linear current signal from 4 to 20 mA in the transducer. Transducers are secured by screw joints in the sleeve which can be a part of the outfit.

Characteristic

- *temperature range from - 200 to 550^{o}C;*
- *stem and lead material - stainless steel GOST 12Ch18N10T;*
- *programmed head sensor transducer with output signal from 4 to 20 mA;*
- *sensor insert damage indication;*
- *output characteristic and temperature or resistance linear ratio;*
- *easy in use while operating excluding sensor disassembly;*
- *sleeve kitting.*

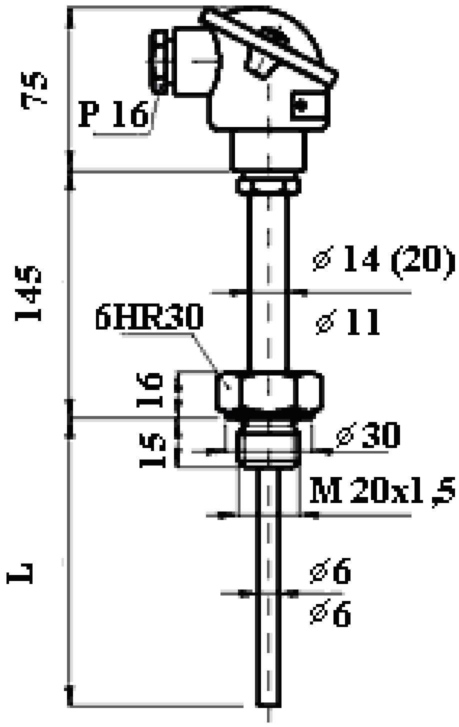
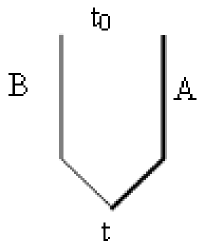


Fig.2.43. T1002 sleeve resistance thermometer

Fig. 2.44. Resistance thermometer: CRT (copper),manufactured by PG «Metran», Chelyabinsk

Thermoelectric transducer (thermocouple) is intended for temperature distant measurement of various media (fluids), including aggressive and explosive liquids. It is widely applied in power and petroleum engineering, metallurgy, chemical and other industries. Thermocouple temperature range is from -100 °C to +1500 °C (depending on the instrument, type of thermocouple and material contacting with the medium being measured (Fig. 2.45).



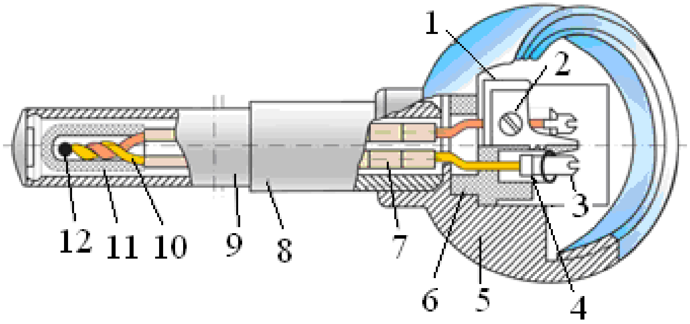


Fig. 2.45. THA thermocouple design: 1 – hold-down cramp; 2 – electrode screw; 3 – compensation lead binder screw; 4 – clamps; 5 – thermocouple head; 6 – clutch panel; 7 – porcelain insulator; 8 – sheath; 9 – fireproof tip; 10 – thermo electrode; 11 – porcelain tip; 12 – hot end

Thermocouple is a temperature sensor, reading the current signal which is proportional to the temperature. As thermocouple produces current due to metal thermo-electrical properties, there is no need for extra power source.

Thermocouple operating principle is based on the ability of two dissimilar conductors to create thermal electromotive force (thermal-EMF) with the junction heating. The conductors, in this case, are called thermal electrodes, while the device – thermocouple.

Operating principle of such thermometers is based on circuit thermal-EMF (TEMF) and temperature change dependence. Four different thermal electromotive forces occur in thermoelectric circuit consisting of two A and B conductors: 2 thermal electromotive forces in A and B conductor junction, TEMF at the end of A conductor and TEMF at the end of B conductor. Total TEMF, occurring with conductor junction heating up to $\boldsymbol{t}$ and $\boldsymbol{t_0}$ temperatures, is:

$$E_{AB}(t,t_0)=e_{AB_{(t)}}+e_{BA_{(T_0)}}, \tag{2.46}$$

Where, $\boldsymbol{e_{BA}}$ and $\boldsymbol{e_{AB}}$ - TEMF, caused by contact potential difference and A & B end temperature difference; TEMF $\boldsymbol{E_{AB}}$ (t t_0) is function from hot end temperature t when cold junction temperature is constant $t_{0.}$

Thermocouple TEMF value depends on thermo electrode material and the difference of hot end and cold junction temperatures. Therefore, cold junction temperature is stabilized or temperature change correction is made when measuring hot end temperature.

Thermocouple are calibrated at a certain constant temperature t_0 (usually t_0 = 0 °C or 20 °C). When measuring, temperature t_0 can differ from calibration value. In this case, an appropriate correction to the final measurement is applied:

$$E_{AB}(t,t_0) = E_{AB}\left(t,t_0^{'}\right) + E_{AB}\left(t_0^{'},t_0\right). \qquad (2.47)$$

E_{AB} $(t_0^{'} t_0)$ correction is made automatically due to the so-called cold junction box and it equals TEMF generated in the thermocouple at $t_0^{'}$ cold junction temperature and cold junction temperature calibration value. Correction is positive if $t_0^{'} > t_0,$ and it is negative if $t_0^{'} < t_0.$ Correction value can be taken from calibration chart.

A variety of thermocouples (Fig. 2.45.) are available, suitable for different measuring applications. Differential thermocouples and thermopiles, series of thermocouples, are applied to measure small temperature difference or to obtain high TEMF.

Cold junction compensation. Correct temperature measurement is possible when the temperature of cold junctions is constant t_0. For this purpose, special leads and thermostatic devices are applied. Due to the leads thermocouple cold junctions are transferred into the constant temperature zone and connected to measuring instrument terminals. *The leads should be thermoelectrically similar to thermocouple electrodes.*

As a rule, thermocouple leads made from base metals are manufactured from the same materials as thermal electrodes are made. The only exception is chromel-alumel thermocouple leads of which are made of copper and constantan to decrease circuit resistance (Table. 2.8).

Fig. 2.46. Thermoelectric transducer: CAT series, manufactured by PG «Metran», Chelyabinsk

The most commonly used thermoelectric transducers (Fig. 2.46., 2.47.) are chromel-alumel (CAT) Metran-231 and chromel-copel (CCT) Metran-232. The above-mentioned thermoelectric transducers are intended for:

- *fluid nonaggressive media measurement as well as aggressive media which do not effect the cable sheath material under the pressure up to 0,1 MPa (Fig.2.47, a);*
- *gas and oil fuel combustion product temperature measurement in pulsating flow which velocity is up to 170 m/sec under the pressure up to 3 MPa (Fig. 2.47, b);*

Table 2.8

Standard calibration thermoelectric transducers

Thermocouple	Calibration	TEMF, mV ($t_0 = 0$ °C ; $t_1 = 100$ °C)	Thermal electrode chemical composition		Temperature range , °C (continuous)	Temperature range, °C (short term)	Tolerance class,°C
			positive	negative			
Chromel-copel (CCT)	ХК68	6,90 ± 0,30	Chromel (89% Ni, 9,8% Сг, 1% Fe, 0,2% Mn)	Copel (55% Си, 45% Ni)	–50…600	800	± (2,2 – 5,8)
Chromel-alumel (CAT)	ХА$_{68}$	4,10±0,15	the same	Alumel (94% Ni, 2% Al, 2,5% Mn, 1%, Si, 0,5% Fe)	–50…1000	1300	± (4,0 – 9,7)
Platinum rhodium-platinum (PPT)	ПП$_{68}$	0,64 ±0,03	Platinum-rhodium (90% Pt, 10% Rh)	Platinum (100% Pt)	0…1300	1600	± (1,2 – 3,6)
Platinum rhodium-Platinum rhodium (PPT)	ПР 30/6$_{68}$	0,431 (при /=300°C)	Platinum rhodium (70% Pt, 30% Rh)	Platinum rhodium (94% Pt, 6% Rh)	300…1600	1800	± (3,2 – 5,2)
Tungsten rhenium – tungsten rhenium(TRT)	ВР 5/20$_{68}$	1,33	Tungsten rhenium alloy			2500	± (5,4 – 9,7)
			(95% W, 5% Re)	(80% W, 20% Re)			

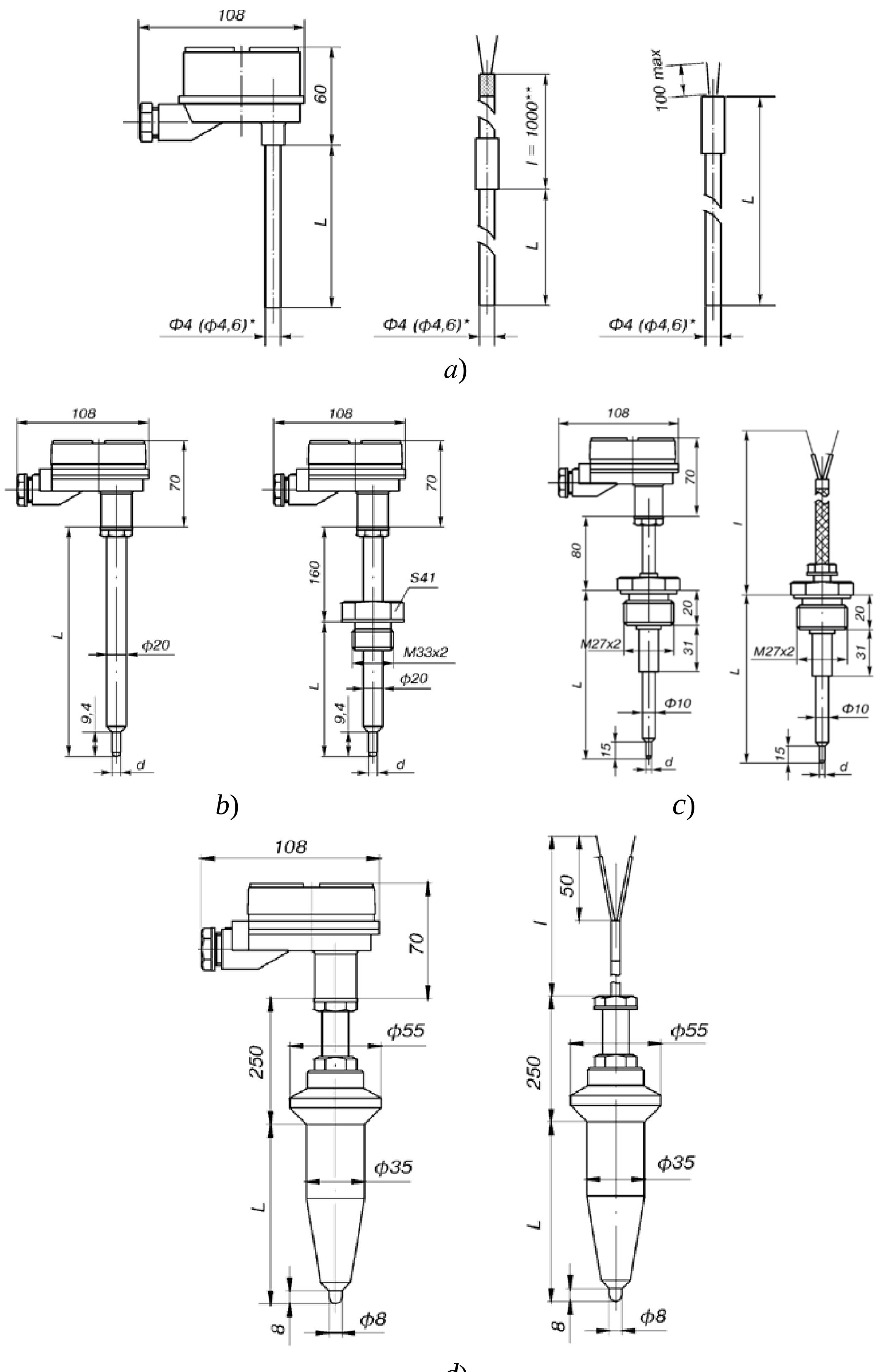


Fig. 2.47. Chromel-alumel (CAT) Metran-231 and chromel-copel (CCT) Metran-232 thermoelectric transducers

- *fluid, natural gas combustion product and gas flow temperature measurement in gas-main pipeline compressor station units when gas flow velocity before the thermal transducer hot end protective screen is up to 70 m/sec (Fig.2.47, c);*
- *temperature measurement in gas- and steam-turbine units (heat-power engineering) when superheated steam flow velocity is up to 60 m/sec, working pressure is 25,5 MPa (Fig. 2.47, d).*

Table 2.9.

Chromel-alumel (CAT) Metran-231 and chromel-copel (CCT) Metran-232 thermoelectric transducer characteristic

Characteristic	Fig. a	Fig. b	Fig. c	Fig. d
sensing elements	1 or 2			
Tolerance class	2			
CAT and CCT thermal transducers are manufactured from thermocouple cable: КТМСп- ХА and КТМСп-ХК or КТМС-ХА and КТМС-ХК				
Temperature range, °C:	CCT: -40...600 CAT: -40...1000	CCT: 0...600 CAT: 0...900	0…900	0…585
Inspection:	Inspection interval – once year Inspection procedure - according to GOST 8.338			

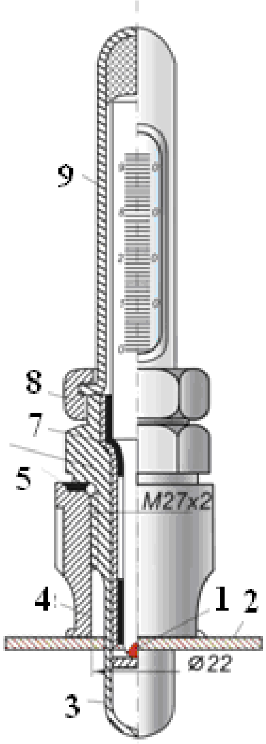
As contact thermometers are available in various designs with different sensing elements, there are certain installation and assembly requirements. Possible ways of flow thermometer installation are given in Fig. 2.48, 2.49, 2.50, 2.51.

Infrared thermometers, often called *pyrometers*, are based on the principle of detector infrared radiation. Radiation intensity and spectrum depend on body temperature. When measuring body radiation characteristics, pyrometer also determines its surface temperature.

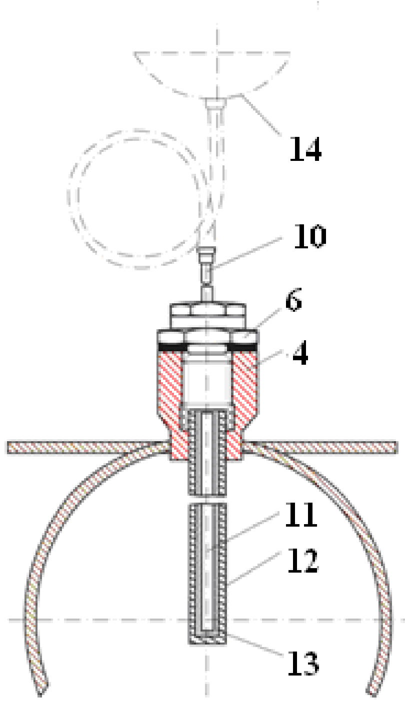
Applications:

- *distant and hard-to-reach object temperature measurement;*
- *moving object temperature measurement;*
- *under-tension object inspection;*
- *high temperature operation control;*
- *transient temperature monitoring;*
- *thin surface layer temperature measurement;*

- *inspection the objects that can not be touched;*
- *low-conductive and heat-capacitive material monitoring;*
- *fast measurement.*



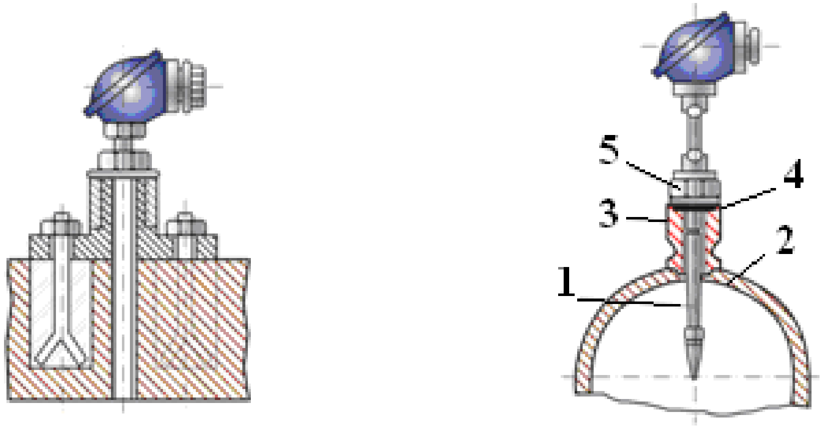
a)



b)

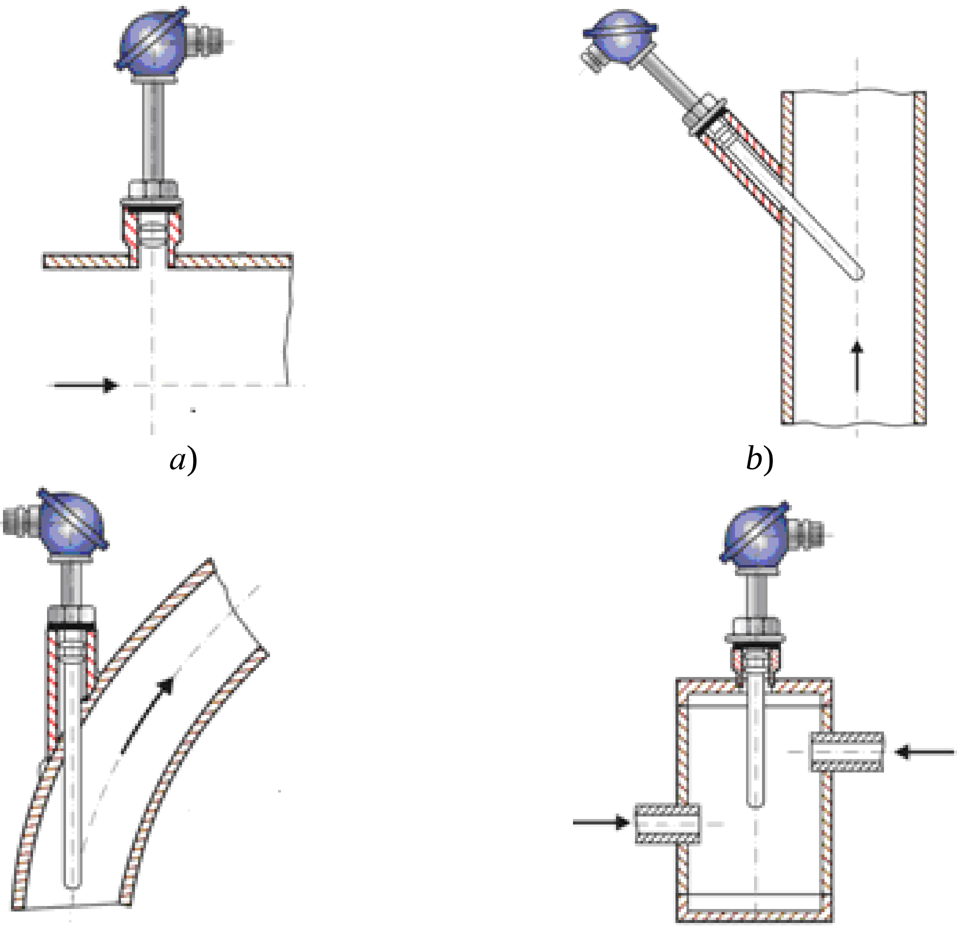
Fig. 2.48. Installation of cased liquid-in-glass thermometer (a) and manometric thermometer thermal phial in pipeline and metal wall (b):1 – thermometer sensor zone; 2 – pipeline ; 3 – sheath void; 4 – lobe; 5 – pad; 6 – nipple; 7 – filler; 8 – captive nut; 9 – sheath; 10 – thermal phial tang; 11 – thermal phial; 12 – protective sleeve; 13 – grits; 14 – manometric thermometer

Pyrometer working temperature range depends on the length of radiation wave sensed by pyrometer detector. As radiation spectrum shifts towards short waves with temperature rise, high-temperature pyrometers waves are shorter. Pyrometer wave working length is not important for a user unlike its temperature range.



a) *b*)

Fig. 2.49. Installation of thermoelectric thermometer in break setting (a) and in pressure pipeline (b): 1 – thermometer; 2 – pipeline; 3 – lobe; 4 – pad; 5 –nipple



c) *d*)

Fig. 2.50. Resistance transducer installation: a) horizontally; b) vertically; c) in pipeline bend; d) with a reamer

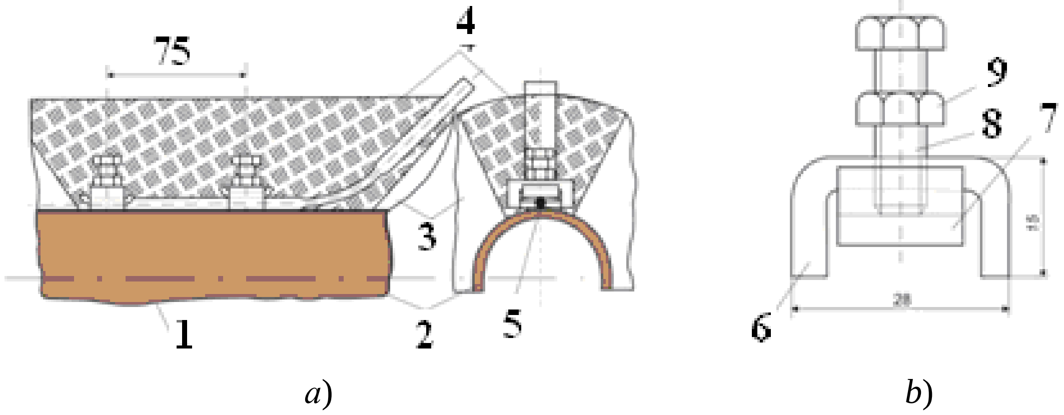


Fig. 2.51. Surface thermoelectric thermometer installation (a) and thermometer hold-down construction (b): 1 – hold-down; 2 – pipeline; 3 – insulator; 4 – insulator layer; 5 – thermometer; 6 –block; 7 – scrap; 8 – bolt; 9 – nut

Pyrometer upper-range value can vary. As measurement is based on noncontact method, there is no temperature field distortion caused by measuring instrument insertion into the medium (fluid) to be measured. Pyrometers provide measurement of flame temperature and gas flow high temperatures at high velocity.

As pyrometer is applied when temperature is transient, its speed performance is an important characteristic. It is defined by time when the setting value is 95% (value setting time).

Radiation capacity setting. For precise body temperature measurement based on its radiation, its emissive capacity should be known. Most surfaces are similar to black body but some of them (i.e. polished metals) differ significantly. As simple pyrometers sense fixed radiation capacity (i.e. often – 0,95), the accuracy is plus or minus a degree or two when measuring reflective surface temperature. In some pyrometers the setting emissivity can be adjusted compensating the errors. Some modern pyrometers have emissivity table including radiation characteristics of many well-known metals.

Pyrometers take the average temperature in the sensitivity area (Fig. 2.52, 2.53). Pyrometer sensitivity area is like a cone the top of which is set to the instrument lens, while its base is on the object surface. Cone height and its diameter ratio ***L:D*** is called pyrometer optical resolution (Fig.2.53), which is one of the basic instrument characteristics. The more the ***L:D***, the smaller the objects a pyrometer can sense at a distance.

Pyrometer sensitivity area can be considered as a cone only at a good distance, and, vise verse, it the distance is too close its form is more complicated. Commonly, it narrows to minimum and then expands to a cone form. The distance ***F***, where the minimum sensitivity area diameter ***d*** is reached, is called focus length (Fig.2.54). ***F*** and ***d*** parameters usually can be found in technical documents. There are special short-focus pyrometers when ***d*** parameter is 5...8 mm in 300...600 mm distance ***F***.

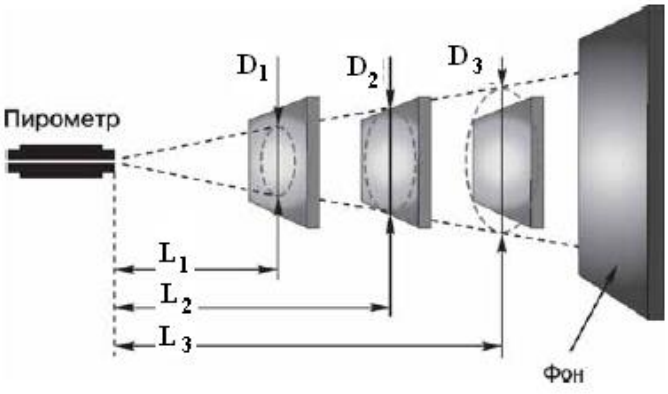


Fig. 2.52. Pyrometer sensitivity area: example L1: D1 – the object is bigger than pyrometer spots (correct - allows to obtain precise temperature measurement); example L2:D2 – the object equals spot diameter (not recommended); example L3:D3 – the object is smaller than pyrometer spot diameter (incorrect, background or surrounding object energy will effect the readings)

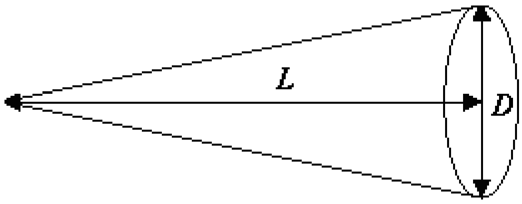


Fig. 2.53. Pyrometer optical resolution

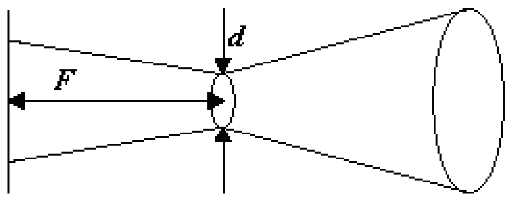


Fig. 2.54. Pyrometer focus length

Simple pyrometers are manufactured without aiming devices and can be applied at a close distance. Laser is used to aim the thermometer to the distant objects. Using *single* laser beam determines a dot near the sensitivity area center. In this case laser beam does not coincide with pyrometer lens optical axis. Therefore, area center is displaced in a fixed distance (1…2.cm. *parallax* error) with respect to the laser pointer.

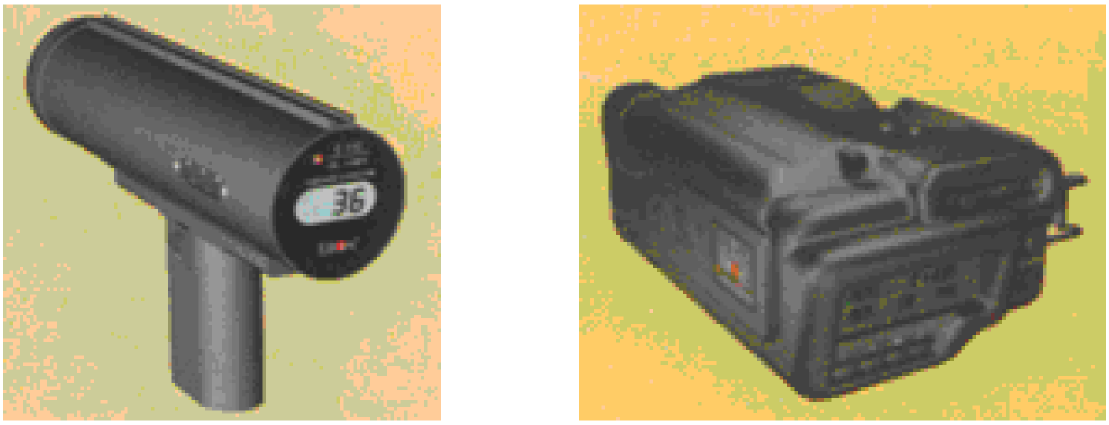
Laser beam escapes from the pyrometer lens center in modern coaxial aiming devices and it always enters the measurement zone center.

Double laser sight shows not only pyrometer measurement zone but also its size. However, it can be set too high when measuring from a close distance. Double laser sight with cross beams is called *cross-laser* commonly applied in short-focus pyrometers, as it is convenient for lens focus location identification.

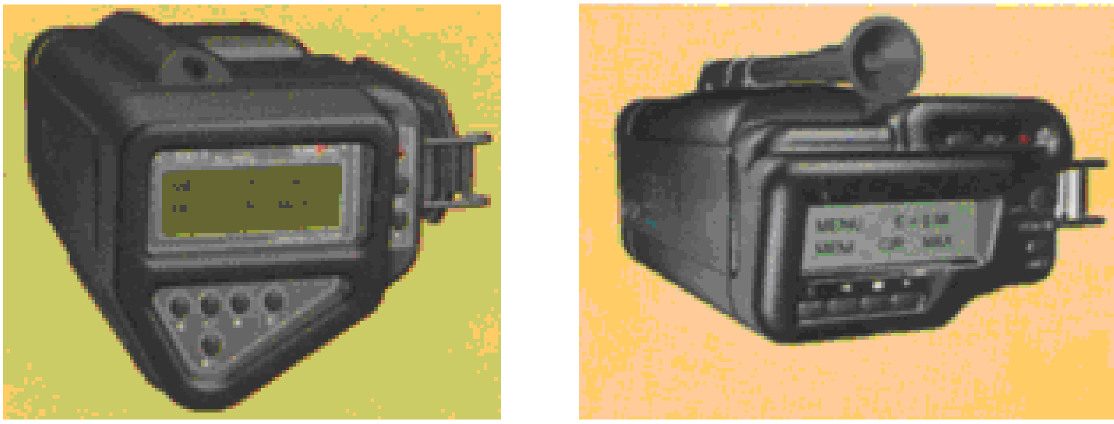
Circular laser sight, formed of several beams, clearly identifies pyrometer measurement zone. Simple circular laser sight disadvantages are: parallax and measurement zone oversize in a close distance. To eliminate these defects the latest sights are formed by several laser beams placed around the pyrometer lens to produce revolution hyperboloid. As this sight identifies precisely measurement zone from any distance it is called *precise circular laser*.

Pyrometers can be portable and stationary. Possible pyrometer constructions are given in Fig. 2.55 and Fig. 2.56. In this case stationary pyrometers are applied (Fig. 2.57.) They are easy-to-work and easy-to-use, however, measurement precision can depend on operator professional skills. Besides, they can be hardly applied in continuous technological process monitoring.

Fig. 2.55. ST Portable pyrometer of the Raynger series: manufactured by PG «Metran», Chelyabinsk



a) *b*)



c) d)

Fig. 2.56. Low-temperature pyrometers: a) «Fakel» C110; b) «Favorit» C-300; c) «Foton» C-300 d) high-temperature pyrometer «Samotchvet» C-500

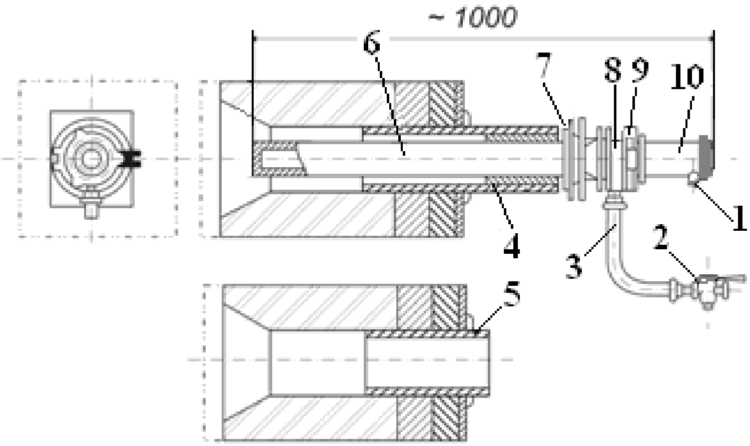


Fig.2.57. «Rapir» pyrometer vertical installation: 1 – wire hose; 2 – tap; 3 – air hose; 4 – cord; 5 – insert flange tube; 6 – carborundum tube; 7 – hold kit; 8 – pipe branch; 9 – swivel device; 10 – TEPA-50 telescope

Secondary temperature measuring instruments

Logometers and automatic bridges are applied as secondary measuring indicating and recording units of resistance temperature transducers, while millivoltmeters and self-balancing potentiometers – as units of thermoelectric transducers and pyrometers (Fig. 2.58).

Due to simplicity and reliability, logometers and millivoltmeters are widely applied as indicating and warning devices for spot and distant temperature control.

Logometers are applied only as units of temperature sensors – resistance thermometers with appropriate calibrations; millivoltmeters – thermoelectric temperature transducers.

Magnetoelectric logometers are intended to measure and record temperature sensed by resistance thermometers, as well as, other parameters by resistance transducers.

Magnetoelectric system millivoltmeters are intended to measure, record and monitore temperature and other nonelectric quantities, the values of which can be converted into direct current voltage variation.

Recording bridges and potentiometers provide reliable controlled parameter reading by recording them on the chart strip. They can control from one to twelve parameters simultaneously depending on the device design and provide automatic device limit parameter alarm.

Automatic balanced bridge basic circuit (Fig. 2.58.) includes: R_1, R_2 and R_3 – resistors, forming three bridge circuit arms, the fourth arm is formed by thermometer resistance R_t; R_p – slide wire; $R_ш$ – slide wire bridge intended for resistance adjustment R_p to set specific value; $R_п$ – range setting resistor; $R_д$ – multiplier resistor intended for scale initial value setting; $R_б$ – current limit ballast resistor in supply circuit; $R_π$ – resistance line setting resistors; T_0 – bridge; C_1 and C_2 – capacitors producing necessary phase shift (90º) between exciting and control winding magnetic flux and required exciting winding resistance; C_3 – capacitor, parallel connected to reversible motor control winding for its bridge for current inductive component compensation in this winding; *SD* – motor intended for chart strip or printer carriage moving.

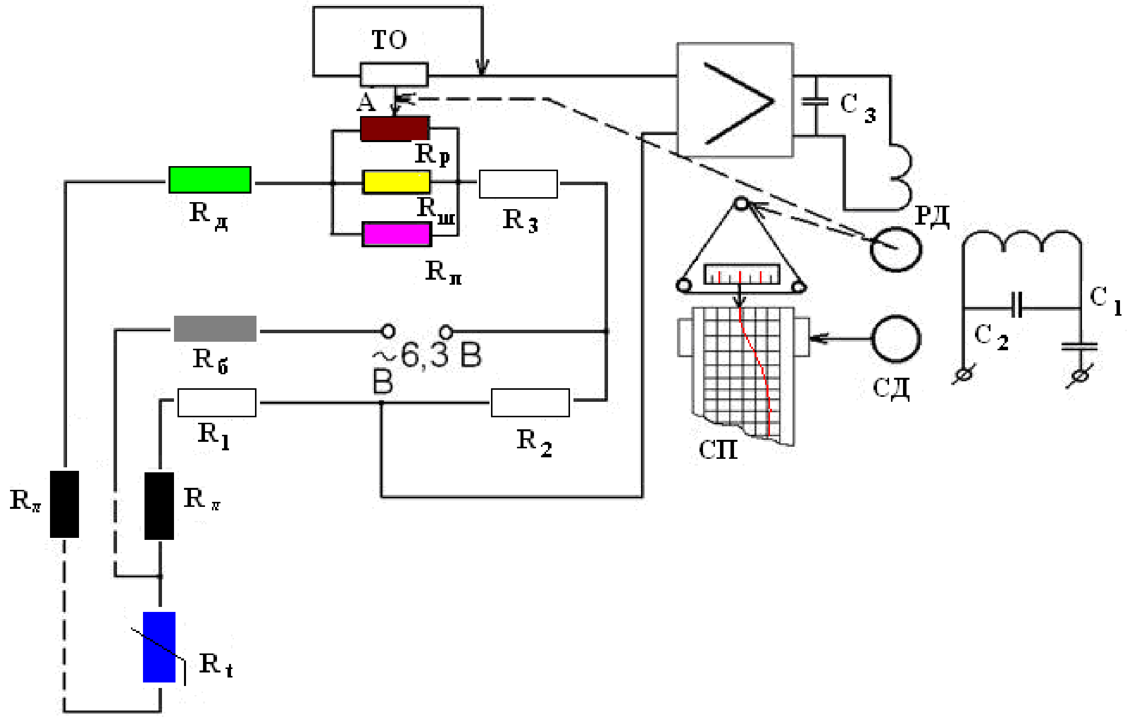


Fig.2.58. Automatic balanced bridge basic circuit

As all resistors are manufactured from manganin wire, atmospheric temperature changes do not influence the resistance values.

Temperature is read in the following way. As thermal resistance change R_t disturbs the bridge circuit balance, error voltage received through input transformer forms bridge *AB* diagonally. Further, an amplifier increases error voltage to set reversible motor *RM*. Rotating clockwise or counterclockwise, depending on the error signal, motor output shaft moves a slider and an indicating needle *IN.* When bridge circuit is balanced, motor output shaft stops so that a slider, an indicator and a needle are in the position corresponding to the thermometer resistance being measured, i.e. object temperature.

In one-channel devices the quantity is continuously read by the chart strip when the carriage moves along the scale. One-channel device printer consists of stylus fixed in the carriage.

In multichannel devices the quantity is cyclically read by drawing color dots in the chart strip with serial number indication when the carriage stops. The figure in the carriage display denotes the channel number which signal will be in the next print cycle.

Multichannel device recorder consists of print drum marked with dots and corresponding figures. The printer units, intended for 4, 6 and 12 dot measurement, are installed depending on the recorder type. Supply unit has the clip with the felt sectors impregnated by paint of different colors to provide reliable measured parameter reading.

2.2.3. Classification of Liquid Level Sensors

Level measurement *- is a level detection of two media (fluids) of different density over the horizontal reference plane.* Level measuring devices are called ***level sensors***.

Oil level measurement is very important both in commercial product balance records and in industrial process monitoring, especially when level control guarantees safe equipment performance. Thus, level sensors can be used either for fluid amount detection (in this case, the scale is standard) or for level deviation control (in this case, scale with a reference value) [8].

In accordance to the measurement conditions and measured medium (fluid)characteristics, different level measurement methods are applied. Excluding distant level reading, liquid (fluid) level is measured by visual reading level sensors. (Fig. 2.59).

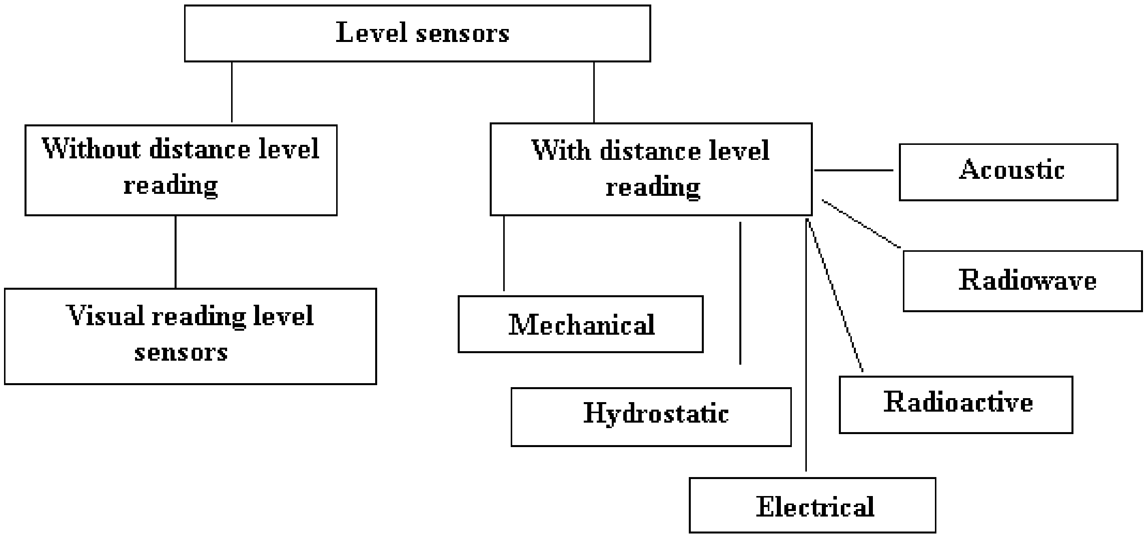


Fig. 2.59. Level sensor classification

Based on the installation, the following types of level sensors are distinguished: indicating level sensors (for continuous measurement) and signaling level sensors (for discrete point level measurement). Level sensors are applied in automatic control system and technological process monitoring.

Based on the operation mode liquid (fluid) level sensors are divided into:

- *mechanical,*
- *hydrostatic,*
- *electrical,*
- *acoustic,*
- *radioactive.*

Elementary level sensors – water-gauge glass based on the law of connected vessels, intended for liquid level monitoring within an enclosed vessel.

Hydrostatic level sensors – counterbalance liquid column pressure in a reservoir by liquid column pressure in a measuring instrument or by its spring response.

Mechanical level sensors – *float-type* when the sensing element is a float at the liquid surface, and *buoy-type* based on the measuring of the buoyancy force affecting the buoy. Float or buoy movement is transferred to the device measuring system through mechanical connections or distant reading system (either electrical or pneumatic).

Electrical level sensors – *capacitance* and *conductometric*. Capacitance level sensor sensing element is a condenser, the capacity changes of which are in proportion to a liquid level change. Conductometric level sensor is based on the measurement of electrodes in the medium (fluid) being measured (reservoir or device wall is one of the electrodes).

Acoustic (ultrasonic) level sensors - based on the phenomenon of ultrasonic vibration reflection from the liquid-gas division plane.

Radioactive level sensors – based on the object radio-element gamma-ray radiography the intensity of which depends on measured liquid (fluid) volume. From the point of design, all level sensors are made for open vessels and for the devices under pressure.

Visual reading level sensors. Visual reading level sensors are based on the fluid level height measurement (Fig. 2.60).

Device (***1)*** is connected to the indicating glass through the stop valves (**2**) (tube 3). As a device and a tube are connected vessels, liquid level H in the tube always equals the level in the device and measured to the scale.

Liquid (fluid) density difference in the controlled reservoir and glass caused by temperature difference (especially if the liquid (fluid) temperature in the tank is high, while the indicating glass is located at significantly distance) is an additional source of errors in such level sensors..

Density difference leads to level difference in the reservoir and indicating glass. As the error can be rather significant, it is decreased by the level sensor thermal insulation or liquid purging from the reservoir before the reading. Such level sensors are applied for water level measurement.

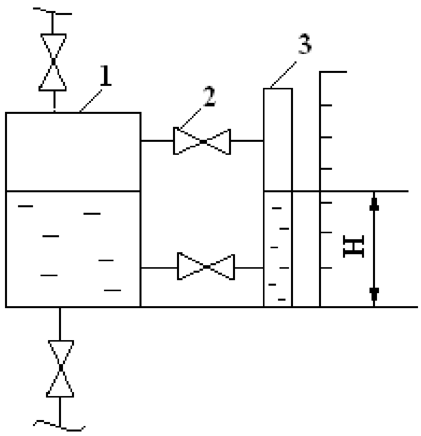


Fig. 2.60. Scheme of elementary visual reading level sensor

Hydrostatic level sensors. Hydrostatic level sensors measure the level of the constant density liquid (fluid) by measuring liquid column pressure. (Fig. 2.61, 2.62):

$$P_{гидр} = \rho g h \;. \tag{2.48}$$

Pressure tube air (***1)*** bubbles through the liquid (fluid) layer. Air amount under pressure is limited by the throttle/choke ***(3),*** ensuring the possible minimum air velocity in the pipeline. Liquid level is defined by pressure difference in a differential manometer (***2***).

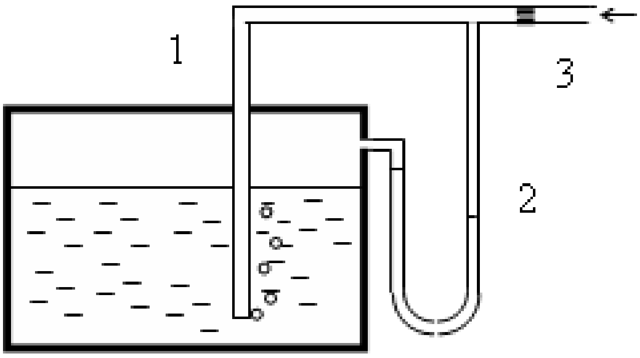
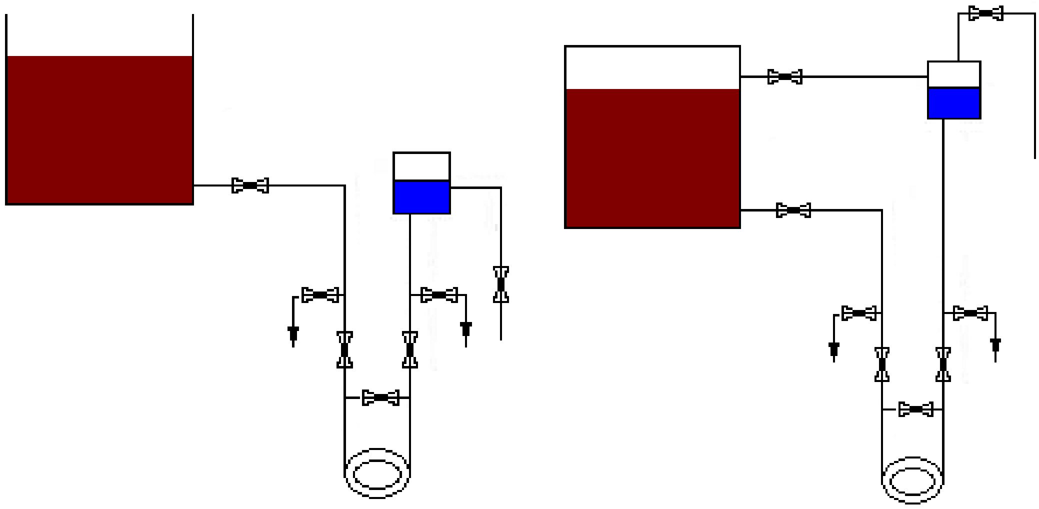


Fig. 2.61. Hydrostatic level sensor

A variety of sensors is available for column pressure or liquid (fluid) weight measurement. The significant error in these sensors is the fact that id fluid density changes then the fluid level itself changes to temperature alteration. To decrease such errors, complex measurement systems are designed. Such devices simultaneously measure not only hydrostatic pressure and fluid density, but also adjust the sensor reading to fluid density. Therefore, to measure hydrostatic level, the pressure or pressure difference measuring instruments can be applied, i.e. commercial differential manometers – float-type, membrane-type and bellows manometers.

*Hydrostatic level sensor measuring liquid (fluid) hydrostatic pressure by differential manometer is called **differential level sensor**.*



a) *b*)

Fig. 2.62. Differential level sensors: a) level measurement in open; b) level measurement in a tank at atmospheric pressure

Differential level sensors are applied for level measurement in open tanks (atmospheric pressure) or in closed (pressure or underpressure pressure) tanks (Fig. 2.62, 2.63). A level vessel filled with the same liquid (fluid) as in the measured tank at a certain level provides a relatively constant liquid (fluid) level in one of the measuring instrument (arms) legs (differential manometer), as well as, in the measured tank. Liquid column height of another differential manometer leg (arm) varies with level change in the controlled device. Each level value corresponds to a pressure drop due to height interval between the measured tank and measuring instrument. Under atmospheric pressure, the level vessel is placed at a zero level mark (Fig. 2.62, a); under normal pressure – at maximum level height (Fig. 2.62, b).

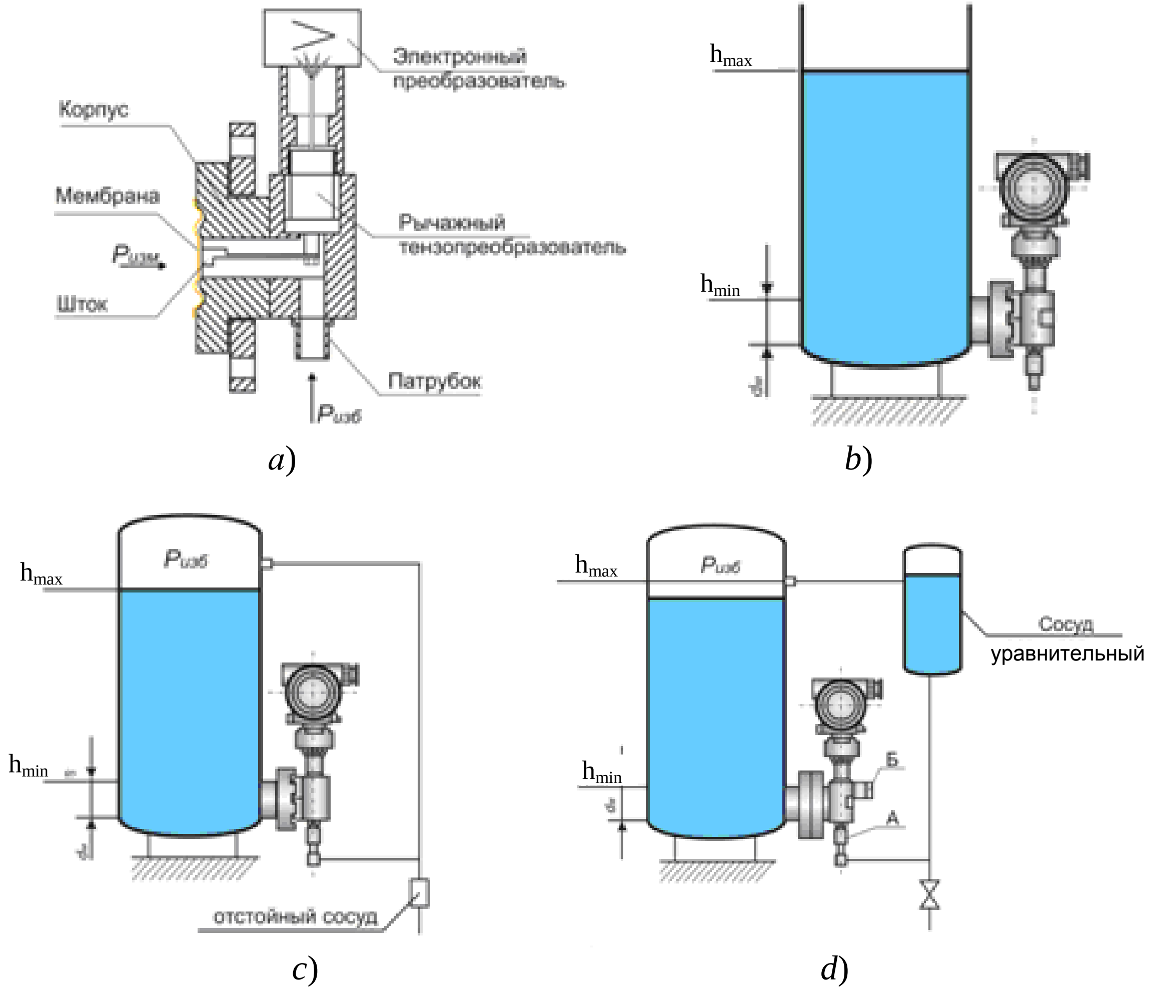


Fig.2.63. «Metran-100-ДГ» level sensor, model 1533: a) elementary diagram; b) level sensor installation for hydrostatic pressure measurement in an open tank; c) tank under pressure; d) closed tank

When the differential manometer is switched on, its pressure drop equals hydrostatic liquid pressure, proportional to the measured level. When measuring aggressive liquid (fluid) level, differential manometer is protected by separation vessels or membrane dividers, in order to fill in differential manometer chambers and tubes with non-aggressive liquid (fluid).

Pneumometric level sensors counterbalance liquid column pressure .and air pressure (inert gas).

As a rule, differential manometers can be measuring transducers, while head gages and manometers are applied in open reservoirs. The main advantage of pneumometric level sensors is the fact that the readings are independent of the temperature regimes of connection lines. Pneumometric level readings are widely applied in aggressive fluid level measurement.

After measuring hydrostatic pressure, not only the level but, also, the product or material mass can be precisely measured, at the same time set fluid density values are for further calculations of the mass itself. Thus, hydrostatic level sensors allow not only to measure maximum and minimum fluid level, but also to define its mass in set mass or volume units.

Hydrostatic smart level sensor APR-2000/Y for measurement in closed tanks is illustrated in Fig. 2.64.

Level sensor operates on the pressure difference transducers which balance the tank static pressure. Hydrostatic pressure measured in the tank at the low separator membrane level is a transformable value. Measured pressure is the sum of hydrostatic pressure of both fluid vapor phases. In most cases, vapor phase density is small, so measured hydrostatic pressure is determined by liquid phase column height and is expressed as liquid phase mirror. A medium (fluid) with high vapor phase density (i.e. propane), the level determine by this method can be considered as theoretical liquid phase level, which, in its turn, would be the sum of actual liquid phase and vapor condensate phase.

Deltapilot S hydrostatic level sensors can be applied for aggressive and explosive environments during ambient temperature drop is significant. (Fig. 2.65.). These sensors determine and indicate tank fluid level, volume, pressure difference, mass, and density.

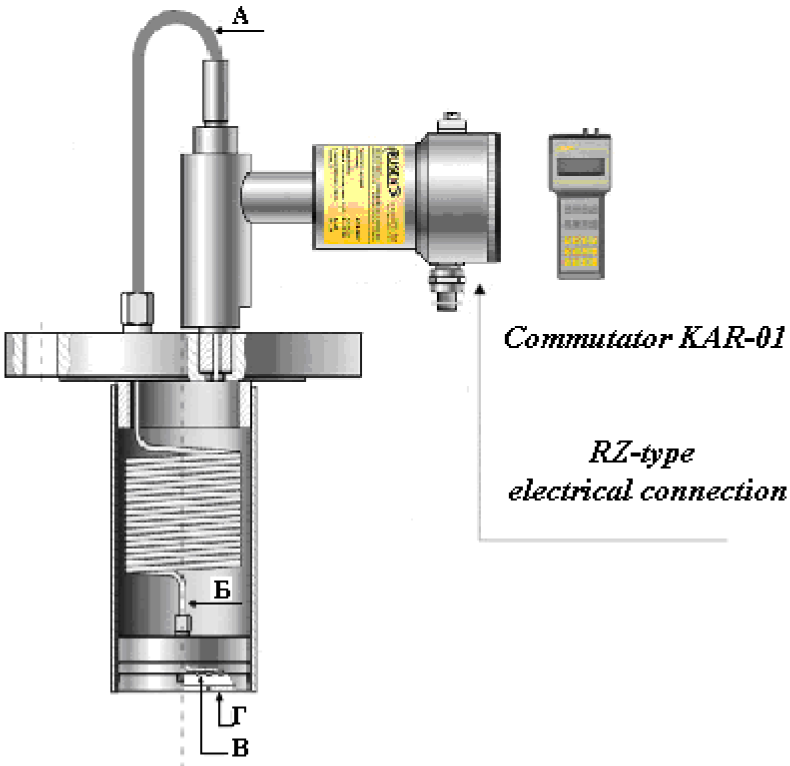


Fig. 2.64. Hydrostatic smart level sensor APR-2000/Y for closed tank measurement: A – capillary reinforced by sheath; B – stainless steel capillary; C – membrane; D – guard ring

Fig. 2.65. Deltapilot S hydrostatic level sensor: manufactured by ENDRESS+HAUSER Company, Germany

Operating mode of the device is based on the hydrostatic pressure measurement of the liquid column which effects instrument measuring unit.

Characteristics features.

- *measuring unit (sensing excess pressure) design excludes the formation of condensate and moisture penetration; resistant to hydraulic shock, 20 times exceeding nominal pressure without any operation failures (measuring unit is filled with silicone)*
- *membrane measuring unit is made of Hastelloy C material – strong and chemical resistant to aggressive fluid effect.*

Level sensor is software measuring instrument including a measuring unit and sealed electronic block. Setting is made according to application conditions: buttons on the device, programs through different digital communication interfaces. Measuring data is transmitted to analog-digital liquid crystal display, computer and control unit displays, recorder, and data indicator.

The device is installed either in the wall, hedge, tank bottom or above the fluid by holders (as a flange unit) (Table 2.10)

Table 2.10

Basic Deltapilot S level sensor technical characteristics

Characteristics	Readings	
Pressure range, bar	–0,9…4	0 … 400
Measurement range resetting factor	10 : 1	
Conventional error, %	± 0,2	
Working fluid temperature, °C	–10 … +100	–10 … +80
Ambient air temperature, °C	–40 … + 85	
Weight, кг	3…15	

Float level gauge. Float level gauge measures the position of the float partially submerged into the liquid. Float submergence level does not change if liquid density is constant. Float level is based on the liquid buoyant force law. Sensing element is a body of arbitrary shape, i.e. float moves vertically with liquid level. Present level value is determined by the fixation of the float location.

Float level gauges are one of the simplest and most reliable level gages. Float level gauges are applied for level measurement in reservoir when the excess pressure is not high. They control liquid level ranging from 50 to 2000 mm. Such level limit value indicators include float-type instruments of the following types: level switch bellows (LSB), level indicator (LI), remote level switch (RLS) (Fig.2.6.6).

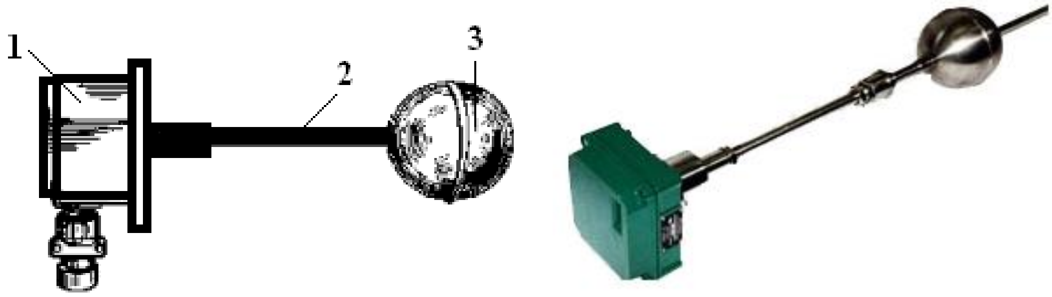


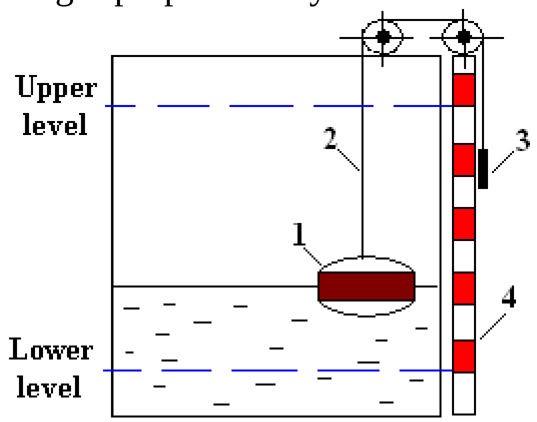
Fig. 2.66. Float level gauge:

1 – gauge body with a micro switch; 2 – shaft; 3 – float

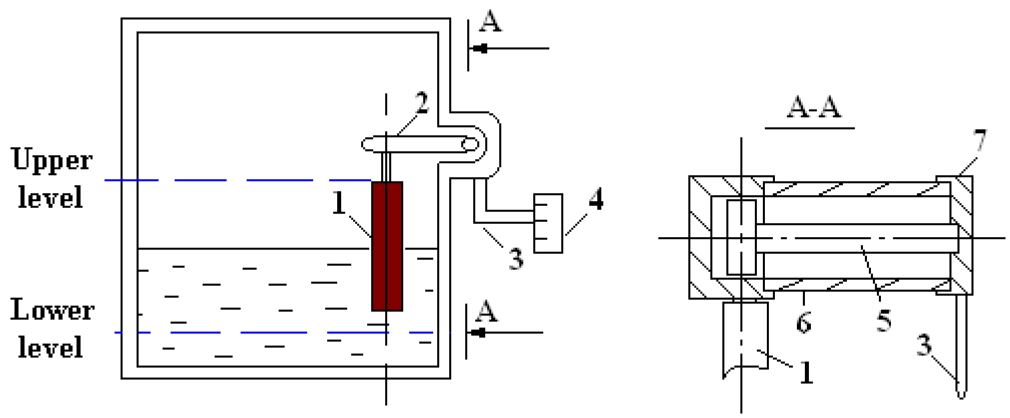
Float (***3)*** (hollow metal sphere), connected through the source (***2)*** to the micro switch (***1)***, is installed in the monitoring liquid (fluid). When level is maximum, the sphere (***3)*** is affected by ultimate buoyant force which, in its turn, rises shift (***2)*** and turns the switch indicating alarm level. (indicating alarm level switch).

There are buoyant and non-buoyant floats. The buoyant float (***1)*** is counterbalanced by the weight (***3)*** connected to the float by a flexible cable (***2)*** (Fig. 2.67, a). Liquid level is determined by a weight position with respect to the scale (***4)***. Measurement limits are set according to adopted values of upper and low filling levels (e.g. oil tank).

Non-buoyant floats (massive buoys) are the most reliable ones (Fig. 2.67.b). When liquid level changes as in Archimedes law, buoyancy force (float weight (***1)***) affecting the lever. Changing moment of forces moves the lever (***2)*** is transferred from the float through the shaft (***5)***, fixed in the bottom (***7)*** to the tube (***6)*** and is counterbalanced by the moment of its torsion. Tube torsion angle changes proportionally to the level value [13].



a)



b)

Fig. 2.67. Float level gages:

a) with buoyant float; b) without buoyant float

Sensing element readings can be received in different ways. As a rule, the float is fitted with a magnet and sealed in a measuring tube and moves along the pilot pin. The magnet involves regulating rheostat (e.g. BM -26 level gauge). Resistance change is converted into electrical output signal providing not only visual monitoring, but also, distant reading transmission which, in its turn, is included into automation system.

A number of float level gauges are based on magnetostriction effect (RUPT-A, RUPT-AM, DUU 2, DUU 4). In this case, float pivot pin includes a guide (waveguide) sealed in a coil, through which current impulses are transmitted. Due to current magnetic field and moving magnet effects, longitudinal deformation impulses form and propagate in the waveguide, where the piezoelectric element is in the pivot top. The device analyzes impulse propagation time and converts this time into output signals.

The pivot pin of magnetic level gauges (e.g. ПМП-062) includes gerkons closed by moving magnet. Level measurement resolution of such devices is about 5 mm. The main characteristic of float level gauges is high measurement accuracy - +/-1…5 mm.

This type of measurement is widely applied, excluding medium where sludging and sticking are possible and, in cases of float and sensing element corrosion. Working fluid temperature: from 40 to 120 ºC, excess pressure: up to 2 MPa; for transducers with flexible sensing element – up to 0,16 MPa. Fluid density - 0,5..1,5 g/cm^3. Measurement range – up to 25 m. Float level gauges can be applied in foaming liquid measurement. They are commonly applied for commercial level measurement of fuel, oil, light products in relatively small reservoirs and tanks.

The main disadvantages of such devices are the float itself presence in the reservoir (sphere seal failure, switch stud corrosion as the result of high humidity of controlled medium), and level measurement difficulties in under pressure tanks.

The following float level gauges - UDU- 10, UP-76-1 are widely applied (Fig. 2.68. and Fig. 2.69.).

Fig. 2.68. UDU Float level gauge: «Veresk»Co , Livny

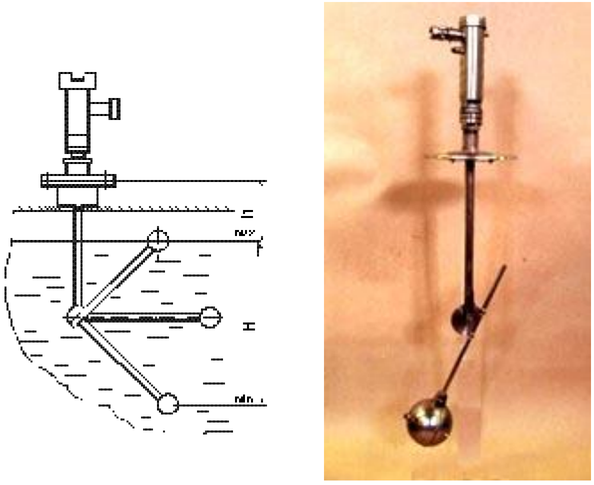


Fig. 2.69. UP float level gauge: Dzerzhinsk

UDU float level gauges with spring counterbalancing and local reading (Fig.2.68) are intended for level control of oil, petroleum, and other liquids, the parameters of which correspond to the specification characteristics. Such gauges are applied in different reservoirs, tanks, and technological devices (Table. 2.11).

UP-76-1 float level gauges (Fig. 2.69) are intended for liquid (fluid) measurement in tanks and vessels which are under atmosphere, vacuum, and excess pressures (Table 2.12). They are recommended for application in tanks with float pivot free movement.

Table 2.11.

UDU- 10 float level gage technical characteristics

Characteristics	Readings
Measurement range, m	from 0 to 20
Basic error at temperature $20^{\pm 5}$°C, mm	± 4
Measured liquid density range, kg/m^3	from 700 to 1200
Temperature measurement limits, °C	from -50 to +100
Float material	сталь 12X18H9T
Weight not more, kg	24,8

Table 2.12.

UP-76-1 float level gauge technical characteristics

Characteristics	Readings
Upper measurement limits, m	0,4; 0,6; 0,8; 1,0; 1,6; 2,0; 2,5; 3,0; 4,0
Measured medium temperature, °C	from -40 to 100
Output signal at power supply 0,125 A of alternating current, 50 Hz, mH	10-0-10
Basic error, %	±2,5
Permissible working pressure, kgf/cm^2 УП-76-1И with connection flange УП-76-1А stamped flange	 up to 2,5 atmosphere
Parts contacting with the measured medium	steel 12Х18Н10Т

Sophisticated level measurement gauges are widely applied in horizontal and vertical Optozond-1500 tanks (Fig. 2.70, Table 2.13). These gauges are intended to monitor and control non-aggressive and non-freezing fluids (oil, refined oil, dark oil product, and black oil) in metal tanks, as well as, further reading transmission to control and indication units (Fig. 2.71.).

Fig. 2.70. «Optozond-1500» float level gage (Introscopy Institute, Tomsk)

Fig.2.71. Control and indication unit «Optozond-1500»

Above-mentioned level gages are applied in petroleum production, petroleum refinery and petrochemical industries, power engineering, technological process monitoring and commercial registration of petroleum products in tank farms.

«Optozond-1500» includes: float level gauges with an intelligent sensing element, float, counterbalance, wheel, and driving gear; distribution block; control and indication unit with power unit, central processing unit, read-only and random-access memories; trunk and connecting cables. Control and indication unit includes numeric display, tank number shift button (1 to 32), indicator bulb, power switch, power cord, trunk cable connector,

ground terminal protection, and interface port. Personal computer and printer can be connected to the control and indication unit through opisolation test voltage up to 1,5 kW.

«Optozond-1500» (URV/3-15) is an information-measuring system with algorithmic and metrological software, which, in its turn, is implemented with "Balans" and other systems through the trunk cable by the interface RS-232.

The system provides efficient function distribution between hardware and software components. Installation method – network port.

RU-PT3 ultrasonic level gages (Fig. 2.72) are applied for total fluid level measurement in tanks.

There are standard and explosion-proof level gauges. Impulse ultrasonic device is a level gauge, the sensor of which is installed in tank with the fluid being measured. Sensor length is not less than the measurement range. The level is sensed by the float moving along the sensor to fluid level. Ultrasonic source having acoustic connection to the upper end of the sensor periodically emits ultrasonic waves, 50 kHz. The next ultrasonic wave is emitted when the previous one is reflected. Time intervals, which are proportional to the level and to the span (in case of reference channel) are measured in every ultrasonic wave cycle. When ultrasonic waves reach the float and reference node, it is detected by electrical signals of the float and reference node interaction due to ultrasonic wave transmission. The signals are detected from the sensor or signal-layer coil wound around it.

Table 2.13.

«Optozond-1500» float level gauge technical characteristics

Characteristics	Value
Level measurement range, m	0.1-15 and more
Basic reduced error, %	0.1
Float level gauges, sensing element, and distribution blocks explosion-proof (GOST 22782.5-78)	1 ExibllBT3
Float level gage, sensing element and distribution block stress protection class (GOST 14254-96)	1P53
Working conditions (GOST 12997-84)	
Control and indication unit	B1 class
Float level gauge, distribution block	Д2 class
УРВ/3-15	P1 class
Relative humidity at 30 °C without moisture condensation, % (control and indication unit)	75
Relative humidity at 25 °C without moisture condensation, % (float level gauge and distribution block)	100
Durability, a year, not less	14

Ambient temperature, °C	
control and indication unit УУИ	+10 to +35
float level gauge, distribution block	-50 to +60
Float level gauge and distribution operation block - explosion hazard: II class (GOST 22782.0-81)	T3 class
Distribution block and sensing element resistance block (GOST 22782.0-81), Joule	20
Dimensions, mm	
Float level gauge	640x276
Sensing element	90x160
Float	380x140
Distribution block	120x50
Control and indication unit	200x50x300

Level gauges are manufactured with rigid-structure sensing element without reference node or with external reference node. Measurement range is up to 12 m. Maximum permissible working excess pressure is up to 2,5 MPa. Total level measurement error according to the digital output:

- ± *2 mm plus 1 for low class when the sensing element length is not more than 4 m (according to technical specification);*
- ± *4 mm plus 1 for low class rigid*-*structure primary transducer with external reference node;*
- ± *(4 or 10) mm for low class rigid*-*structure primary transducer without external reference node.*

Output signal:

- *analog 0-5 mA or 4-20 mA;*
- *digital (interface RS-485);*
- *level indication on the digital display;*
- *relay, with programmed upper and low critical level signal settings (switching power by output relays up to 100 volt-amper).*

Fig.2.72. RU-PT3 Ultrasonic float level gauge

(«Teplopribor», Ryazan)

Buoy level gauges. Buoy level gauges are based on the Archimedes law. Buoy level gauge sensing element is a massive body (buoy) vertically hung in the vessel where liquid level is sensed. As liquid level changes, the buoy submergence level also changes because of liquid buoyancy force compensation, resulting from vertical stain. Buoy submergence indicates the liquid level in the vessel. Buoy level gauge has a linear characteristic. The more buoy cross-section area is, the higher is sensitivity.

Buoy level gauges are intended for continuous tank liquid level measurement, interface level measurement, fluid density determination which in its turn is proportional to buoy location change. They are ideal for level measurement of different liquids in a wide temperature and pressure ranges. Buoy level gauges are applied in different industries. Due to modern electronic engineering level gauges can be embedded into Process Control Sytem has different built-in design level gauges.

Buoy level gauges are intended for level measurement ranging from 10 meters, at temperatures -50. to +120ºC (range +60 to +120ºC with heat-output nipple, at temperatures from 120..400°C devices operate as level indicators) and pressure up to 20 MPa with 0,25..1,5% accuracy. Liquid density is from 0,4 to 2 g/cm^3.

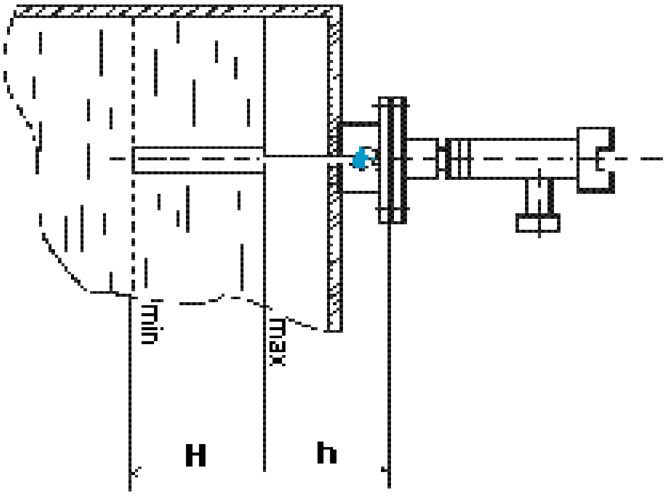


Fig. 2.73. UB-76-1 buoy level gauge
(«NIPOM», Dzerzhinsk)

Buoy level gauges are available in two types: UB-*76-1I – for tanks under excess or vacuummetric pressure; B-76-1A – for tanks under atmosphere pressure*.

Table 2.14

Buoy level gauge technical characteristics

Characteristics	Readings
Upper level measurement limits, m	0,4; 0,6; 0,8; 1,0; 1,6; 2,0; 2,5; 3,0; 4,0; 6,0; 8,0
Measuring fluid temperature, °C	up to 100
Measuring fluid density, g/cm^3	from 8 to 2,5
Output signal at alternating current supply 0,125 A and 50 hz, mH	10-0-10
Basic error, %	±2,5
Permissible working pressure, kgf/cm^2: for УБ-76И with connection flange for УБ-76А with stamped flange	 up to 2,5 atmosphere

Pneumatic buoy level gauge (Fig. 2.74) is intended for the control of liquid level or interface level between two immiscible liquids in automatic technological process control systems with significant fire safety requirements. The devices are applied in petroleum engineering and chemical industry with indicators and actuating devices which operate from the standard pneumatic signal 20-100 KPa.

Fig. 2.74. Pneumatic buoy level gauge
(«Teplopribor», Ryazan)

Basic technical characteristics:

- *measurement range – up to 16 m.*
- *Maximum permissible working excess pressure – up to 16 MPa.*
- *Error ± 0,5 %, ± 1,0 %, ± 1,5 %.*
- *Power supply – pressurized air up to 140 kPa.*
- *Output signal – pneumatic from 20 to 100 kPa.*
- *Measuring liquid temperature - from - 50 up to + 200 °C; when heat-output nipple is applied, the temperature can be from -50 up to +400 °C.*

Table 2.15

Pneumatic buoy level gage component materials

Materials			
Buoys and suspensor	Connection flange and cantileve	Spaces	Membranes
steel 12X18H10T	steel 12X18H10T	teflon	alloy 36НХТЮ
steel 08X17H15M3T	steel 08X17H15M3T		steel 06ХН28МДТ
steel 06ХН28МДТ	steel 06ХН28МДТ		

Electrical level measurement methods

Liquid level measurement method is based on difference between liquid electrical properties and gas-vapor mixture. Electrical properties are substance dielectric constant (tramsmissability) and substance electroconductivity.

Conductometric method is level measurement of primary transducer electric conductivity to level value.

Capacitance method is capacitance measurement of primary transducer change to measured fluid level. Usually a primary transducer is concentric cylinders [14].

Capacitance method provides reliable level readings (1,5% accuracy). Like float level gauges, buoy level gauges have the same limitations: - medium should not stick to and deposit in the sensing element. However, unlike float level gauges buoy level gauges can be applied both in liquids and grainy substances (grain size – up to 5 mm.). The main restriction of the capacitance measurement method is fluid homogeneity, i.e. the fluid should be homogenous at least where the sensing element is placed.

Capacitance level gauge. Capacitance level gages are based on the capacitance change of the condenser, formed by sensor electrode and tank wall when fluid level changes. Condenser capacitance depends on three factors:

- *Distance between electrodes;*
- *Electrode area;*
- *Fluid dielectric constant (transmissibility).*

Capacitance transducer is formed by one or several pivots/rods, cylinders or plates partially submerged into the fluid (Fig. 2.75). Capacitance level gauges are designed for high temperature and pressure applications, for aggressive medium, in cases of fluid adherence on gauges or vessel walls, and in medium with abrasive impurities.

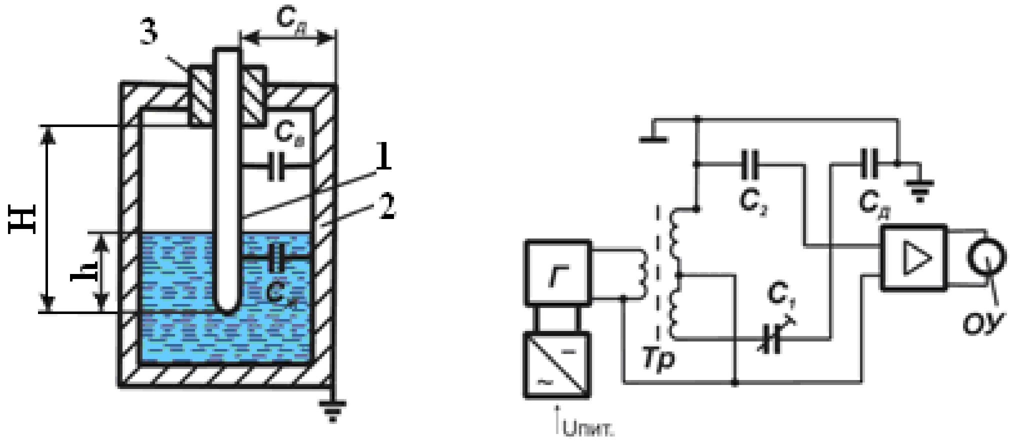


Fig. 2.75. Capacitance level gauge design:
1- electrode; 2 – transducer body; 3 - collar

Capacitance change depends on the fluid height ***(h)*** and its dielectric constant (transmissibility) ***(e)*** (Fig. 2.76).

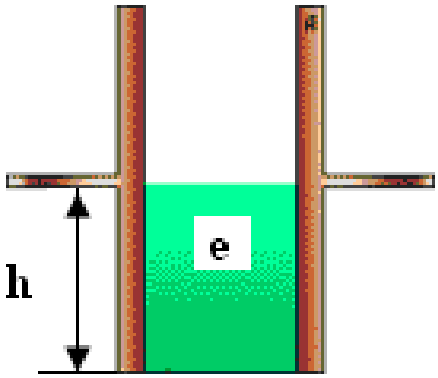


Fig. 2.76. Capacitance transducer

Conductivity fluids are those with specific resistance not less than *10^6 Ohm×m and dielectric constant (transmissibility) from 7 and more.*

Table 2.16.

Liquid dielectric constant

Liquid	Dielectric constant (transmissibility)
Alcohol	3
Petrol	2…3
Chloroform	5,5
Glycerin	1,2
Diesel fuel	2,1
Oil	2,1
Water	81

Capacitance level gauge sensing element is a condenser the plates of which are submerged into the medium. Capacitance transducer design varies to liquid dielectric constants (transmissibility). A sensing element can be either concentric tube with the space filled up with fluid or a pivot where tank walls are as the second plate. If the fluid is conductive the sensing element is covered by insulator, usually teflon. Liquid level change leads to the change of the sensing element capacitance, which in its turn, is converted into electrical output signal.

Capacitance transducer application is in accordance to working fluid parameters: temperature -40…+200 ºC, pressure – up to 2,5 MPa, measurement range – up to 3m. (30 m. – for flexible and cable sensing element).

ISU-100, DUE-1**,** Multicup capacitance level gauges are the most widely applied ones. A wide range of modifications intended for various temperatures, climate conditions and medium applications including aggressive and explosive fluids, is available as DUE-1 gauges.

Conductive level gauges. Resistive level gauges are applied to control the level of conductive fluid. These gauges include electric circuit with specific ohm resistance. Resistive level gauge is a closed circuit in the medium.

High-frequency resistive level gauges as transducers of uniform or non-uniform line segments are applied.

The disadvantages - such gages can not operate in viscous and crystallizable medium of solid accumulations and adherence on transducer electrode. [15].

One example of such level gages is conductometric level gauge ROS-301 (Fig. 2.77.), used for signaling and conductive fluid level maintenance within set limits of three points in one or even different tanks.

Fig. 2.77. Conductive level gauge ROS-301(«Teplopribor», Ryazan)

Characteristic features – medium parameters, length of submerged section and gauge design are illustrated in Fig. 2.79 and Table 2.17.

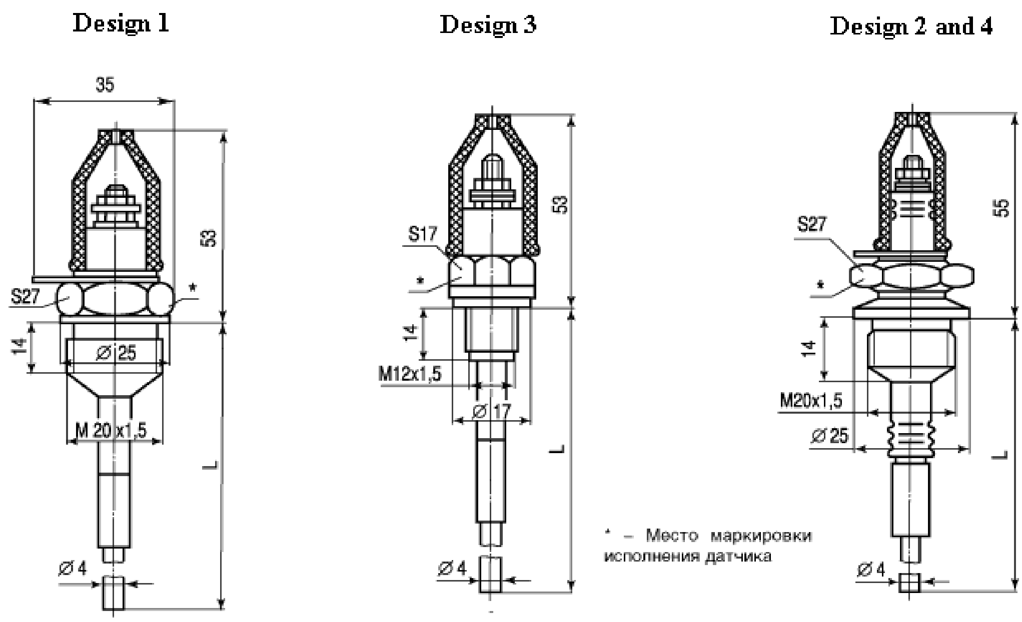


Fig. 2.78. Gauge dimensions and installation size

Table 2.17

Technical characteristics of conductive level gauge ROS-301

Characteristics	Readings
Electrode material submerged into control fluid	steel 12X18H10T
Measuring fluid temperature: Teflon insulator Ceramic insulator	Not higher ºC: 200 250
Working pressure, MPa Teflon insulator Ceramic insulator	 2,5 from 2,5 to 6,3
Specific conductivity, Ohm/m	not less 0,015
Immersion part length	0,6 at vertical installation or 0,1 at horizontal installation
Ambient temperature, °C	sensor from -50 to +70; transmitting transducer from +1 to +35

The device includes transmitting transducer and three sensors. The sensor (Fig. 2.78, 2.79, 2.80) includes: shell (***1)***, electrode (***2)*** and cap (***3)***, to seal the cable connected to electrode terminal.

Transmitting transducer (Fig. 2.79) includes: shell (***1)***, cover (***2)***, electronic module (***3)***. There are four light filters (***6)*** on the cover (***2)*** for power and set level value indication. External cables are screwed and sealed by the spaces (***4)*** with holes corresponding to the outer cable diameter. There is a ground screw (***5)*** on the device shell.

Operating principal is the conversion of electric resistance change between the electrode and reservoir wall into electrical relay signal.

When the sensor electrode is submerged into the measuring fluid, resistance decreases (Rcp < 5000 Ohm), relay responds and light-emitting diode of corresponding circuit illuminates. If there is no measuring fluid, the resistance increases (Rcp > 5000 Ohm), and relay releases and light-emitting diode extinguishes.

The device has three independent channels to control three fluid levels in one or even different tanks.

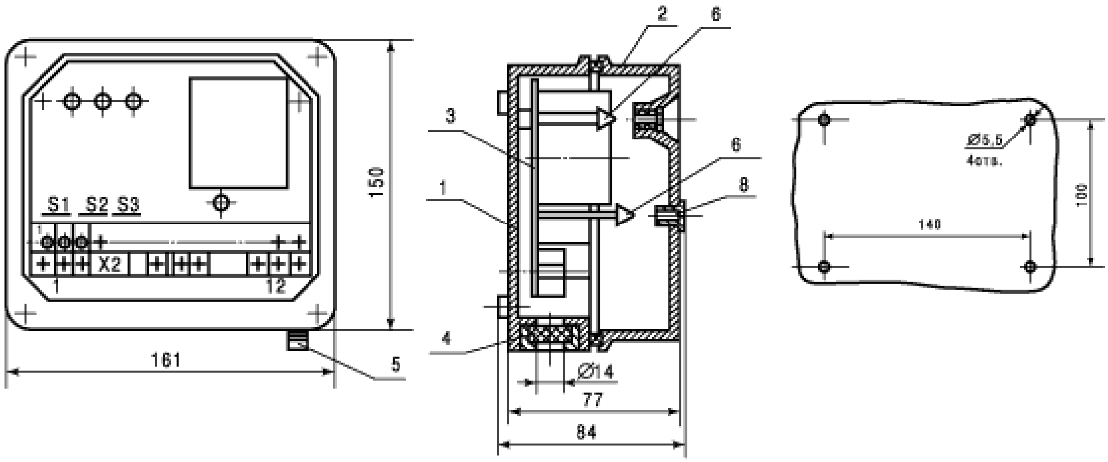


Fig. 2.79. Transmitting transducer and installation marks on the panel

Acoustic level measurement methods

Acoustic level impulse location method (in gas medium) is widely applied. These level gauges are based on non-contact measurement, i.e. gauge sensing element is a transmitter installed in the upper part of the tank and non-contacting with measured fluid. (Fig. 2.80, 2.81).

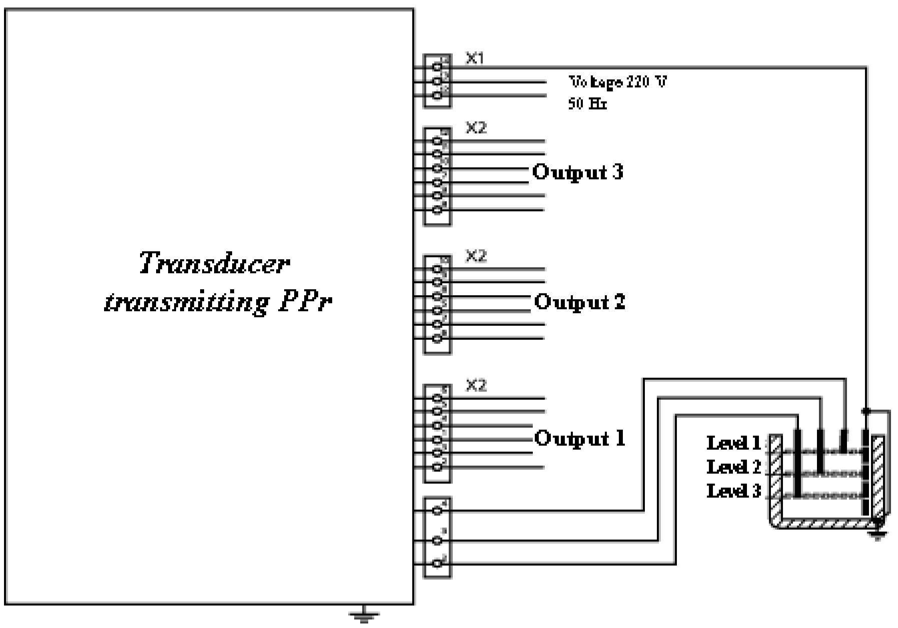


Fig. 2. 80. Electric circuit device scheme ROIS-301

Such gauges are ideal for fluids of different physicochemical parameters. They are suitable for measuring the level of various fluids, including viscous, non-homogeneous, aggressive, and explosive. Non-contact method determines high-efficiency of primary transducers and unified automatic device control.

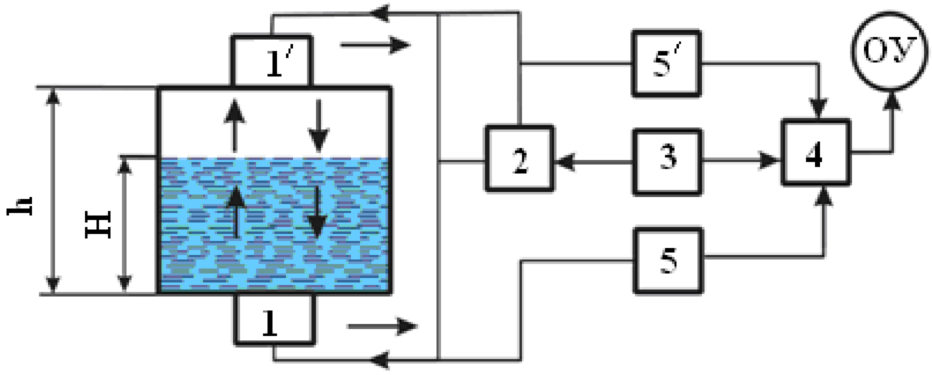


Fig. 2.81. Ultrasonic level gauge: 1 and 1' – piezoelectric transducer; 2 – impulse oscillator; 3 – packet oscillator; 4 – measurement scheme; 5 and 5' – detector-amplifiers

Based on the operation mode, the following types of acoustic level gauges are distinguished:

- *location;*
- *absorption;*
- *resonance.*

Location level gauges are based on the ultrasonic vibration effect reflected by liquid-gas interface. The level is determined by ttransmission time of ultrasonic vibrations from the source to the gauge after their reflection from the surface interface phase.

Absorption level gauges determine the level in accordance to the attenuation of the ultrasonic intensity during its transmission through the fluid or gas layers.

Resonance level gauges are based on the measurement of the gas vibration frequency itself, which is above the fluid level, and in its turn, is influenced by the fluid level. [8].

Resonance level gauges (Fig. 2.82, 2.83) are intended for accurate distant measurement of liquid level, including explosive fluids in tanks of different designs and applications.

Fig. 2.82. Acoustic transducer (Russia Patent № 2249186 of 27 03.2005)

Fig. 2.83. Spark-protecting unit

Resonance level gauges (Fig. 2.84) measure air chamber length of the tubular resonator which is partially submerged into the fluid being measured. Length gauge is an interval between the vibrations excited in the resonator air chamber. Tubular resonator (***1)*** is installed on the tank with the fluid to be measured. The lower tubular resonator end is submerged into the liquid. Acoustic transducer (***2)*** is connected through line (***3)*** and spark-protecting unit (***4)*** to the signaling processor (***5)*** which provides signal processing and reading indication. Both microprocessor unit and personal computer can be applied as a signaling processor.

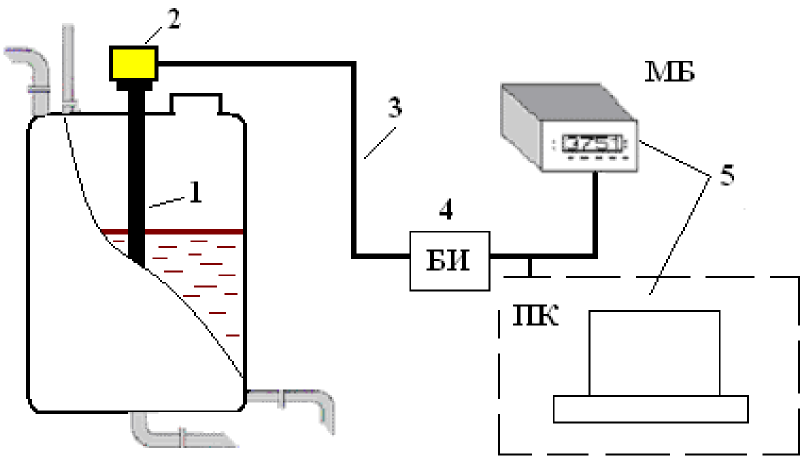


Fig.2.84. Scheme of resonance acoustic level gauge

Radar (radio wave) level gauges. Radar level gauges are the most versatile level measuring devices. Since these gauges do not require physical contact with the fluid being measured, they are ideal for aggressive, viscous, heterogeneous fluids and grainy substances. Unlike ultrasonic non-contact level gauges, radar level gauges are less affected by temperature and pressure in the tank and by their changes, and, at the same time, are more resistant to foaming, vaporous and dusty environments. Radar level gauges provide high accurate measurement (up to +/- 1 mm.), making them useful in commercial record systems. At the same time one major disadvantage of radar is the relatively high price of such gauges.

Radar level gauges are executed in variety of techniques.

Radio-echo level gauges are based on the electromagnetic wave reflection from the interface between the fluids with different electrical and magnetic properties.

Electromagnetic wave speed propagation $\boldsymbol{U}$ in a medium is defined by dielectric constant (transmissibility) $\boldsymbol{\varepsilon}$ and magnetic transmissibility $\boldsymbol{\mu}$ values:

$$U = \frac{C}{\sqrt{\varepsilon\mu}}, \tag{2.49}$$

where, $\boldsymbol{C}$ *– light speed in vacuum.*

The level gauge includes: oscillator, receiver of electromagnetic energy (***2)*** and time interval circuit. The level is defined by the measurement of the interval between signaling moment and the moment of reflected signal receiving.

Ranging is through the gas medium above the liquid. If the fluid is not electro conductive, then the ranging is through the fluid itself. As oscillators are not affected by fluid, gas magnetic permeability and dielectric constant (transmissibility) are not high and practically independent on parameter changes and gas properties, the ranging through the gas is more preferable. However, as these gauges are sensitive to foreign objects, such as vessel walls in propagation zone, the modern radar systems are based on the ranging through the wall of the working vessel. Microwave radar level gages are examples of such systems.

Microwave radar level gages. Microwave radar level gauges are considered to be the most sophisticated and high-technological measuring devices. Microwave electromagnetic radiation is used for working zone probing and identification of the distance to the object being controlled. Nowadays, two types of microwave level gages are applied: impulse and FMCW (*frequency modulated continuous wave*).

FMCW level gauges are based on the continuous linear frequency-modulated signal radiation and simultaneous reflected signal reception of one and the same antenna. The final signals are processed by special, which in its turn, provides desired accurate echo-signal frequency determination. Frequency difference of direct and indirect signals in each time interval is proportional to the object distance under control. *BM-70* **,** *Apex*, domestic *Bars-314I*, *Bars-351I* are examples of FMCW level gauges.

Impulse microwave level gauges emit signals in a impulse mode while the reflected signal is received in the intervals of the source radiation impulses. The device reads the transmission time of both direct and indirect signals, determining the distance to the object surface under control. *Micropilot M* (Fig. 2.85) level gauges are

Fig. 2.85. Micropilot M microwave level gauges

based on the above-mentioned operation mode.

Usually radar level gauges are executed in various frequencies, from 5,8 to 26 GHz. The higher the frequency, the narrower the beam and the more intensive the radiant energy, hence, the stronger reflection.

Therefore, high-frequency level gauges are ideal for fluids with low dielectric constant (transmissibility) and reflectance. They are also applied in vessels of different equipments to eliminate radar working zone. At the same time, high-frequency level gauges are affected by dusty, vapor environments and working surface vibration, as well as, by particle adhesion to the to the antenna due to more intensive signal propagation. In the latter case, it is better to use level gauges executed at 5,8..10 GHz frequency.

Another important characteristic feature affecting the signal formation is the size and type of the antenna. The following types of antennas are distinguished: horn (canonical), pivot, tubular, parabolic, ad planar. The larger the size, the stronger and the narrower is the signal emitted by the antenna, and the better is the reflected signal reception.

Horn antenna is the most universal one. As a rule, it is applied in big vessels intended for monitoring a wide range of fluids with different dielectric constant (transmissibility). It operates under complex conditions providing the measurement range from 35 to 40 m. (if fluid surface is smooth).

Tubular antenna is a built-on loaded waveguide. It forms the strongest signal due to propagation decrease. It is ideal for foam fluids - foaming, turbulent, and fluids with low dielectric constant (transmissibility). Its level measurement range is quite small.

Planar and parabolic antennas applied in commercial record systems provide rather high accuracy (up to +/- 1 mm.).

PBP-102 radar level gauge

PBP-102 radar level gauge is (Fig. 2.86) applied for monitoring turbulent, aero, viscous and aggressive fluids, as well as, thick pastes, emulsions, and slurries. The readings are independent of fluid density and volume, multifluid

Fig. 2.86. PBP-102 radar level gauge (NPO «Saturn», Ukraine)

medium. Medium temperature ranges from -40 to +150°C, while tank pressure is up to 10 Bar.

The device includes electronic equipment protection units for elcetriacl impulse wave overload caused by lighting and industrial moises.

RVR-102 radar level gauge is based on the continuous frequency-modulated microwave signal ranged within 3 cm which is unique. Level transmitter emits the microwave signals to the working fluid through a narrow-beam antenna. The reflected signal is constantly compared with the transmitted one in the receiver. The frequency difference between the transmitted and reflected signals formed due to modulation, is proportional to the distance from the gage to the fluid surface which, in its tern, defines the fluid level. Software data processing provides high measurement accuracy and, further forms commercial flow rate data banks regardless of the number of monitoring tanks equipped with level gauges.

The device has immobile parts and is easily installed on the tank hatches. Such device units operate in vaporous environment at pressure up to 10 Bar and temperature range from -40°C to +150°C. Device units installed outside the tank can operate at temperature range from -40°C to +50°C, humidity 98% when temperature is +35°C.

Table 2.18.

Technical characteristics of radar level gauge RVR-102

Characteristics	Readings
Measurement range, m	from 1 to 30
Measurement error, mm, (not more)	±1
Measurement time, c, (not more)	5
Device weight, kg	20
Hatch diameter is 300 mm for parabolic antenna	
Hatch diameter is 150 mm for horn antenna	
Reading indication by 5 grade digital display	

Measurement unit installation arrangements. Radar level gauge aperture angle can be defined in accordance to the data in the Table 2.19.

Table 2.19

Aperture angle

Distance D from flange plane (m)	1,2	2,4	4,0	7,6	10,7	13,7	16,8	19,8	23,0	26,0	30,0
Distance d from flange axle to zone border	0,15	0,3	0,6	0,9	1,3	1,65	2,0	2,4	2,75	3,1	3,5

If the level gauge is installed on the tank through the inspection hole, fluid level measurement results are significantly influenced by fluid surface and the objects in the radiation zone. To provide high accuracy in complex operation conditions, second and third level gauge installation arrangements are more applicable.

In tanks with a floating roof, the level gauge is installed on 150-200 mm D discharge perforated pipe.

If the fluid being measured is turbulent in the technological tank, then 25-30 mm D perforated waveguide is applied.

The measuring unit (Fig. 2.89) is fixed by the flange in the upper part of the tank by 8 screw-bolts. Deviation of the reservoir flange plane where the measuring unit is mounted should be not more than ±1°C. Power supply and connection with the secondary transducers are carried out by four-line shielded cable of 8-12mm OD. Line length is up to 500 m.

ПВ-2 secondary transducer (Fig. 2.89, 2.90) is a shielded unit. Shield hole is 118x112 mm. The matching site depth considering shoes and preventers is not less than 200 mm. Holders are fixed by standard screws after the device has been installed in the shield. Installation of radio level gauge RVR-102 is illustrated in Fig 2.87 and its connection sizes in Fig 2.99.

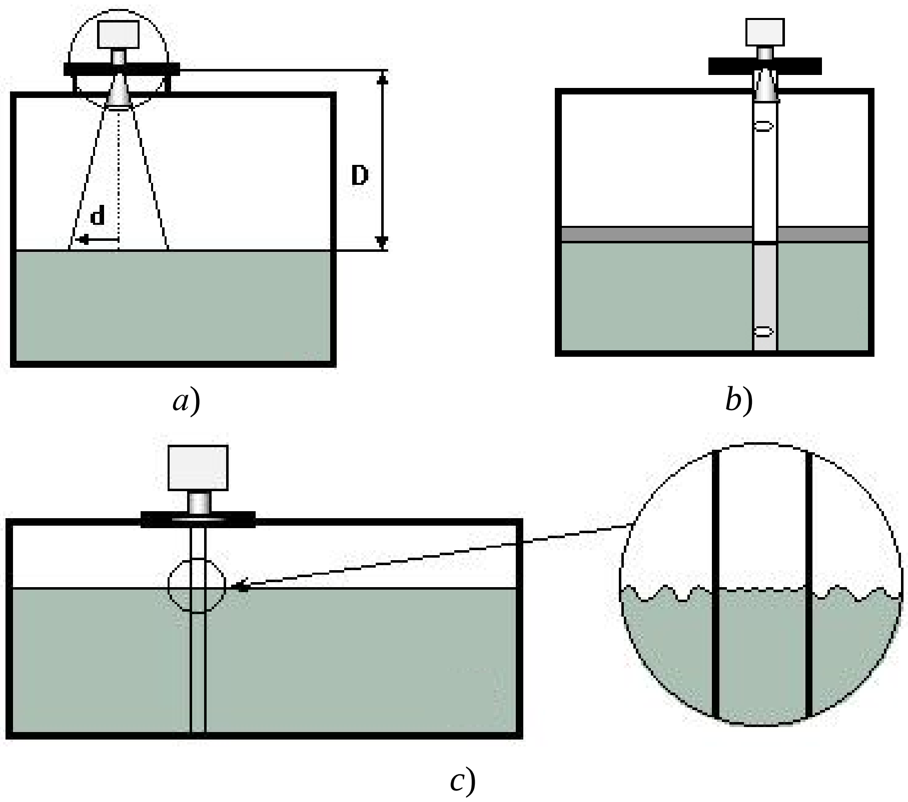


Fig. 2.87. level gauge RVR-102 installation arrangement: a) on the tank through the inspection hole; b) on the tank with floating roof; c) on technological tanks

Secondary transducer power supply - alternating-current voltage (220V). Secondary transducer provides calibration, measuring level indication in the digital display and level value setting on the keyboard. There are computer and analog outputs, as well as, relay output for control and alert levels.

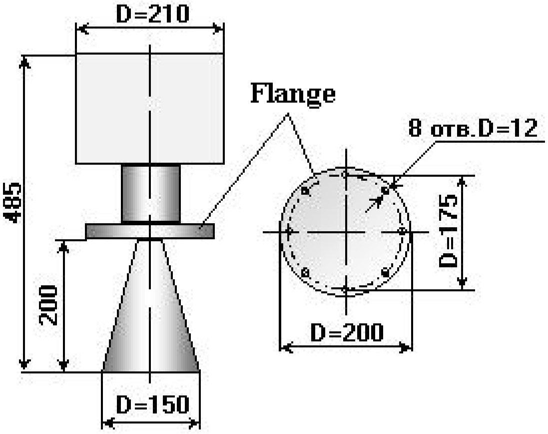


Fig. 2.88. Basic level gage RVR-102 dimensions

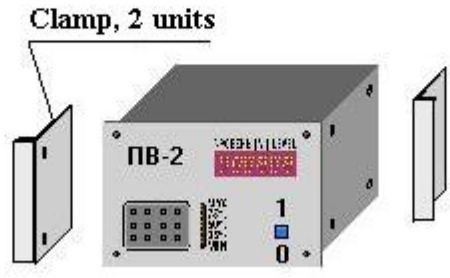


Fig. 2.89. Secondary transducer

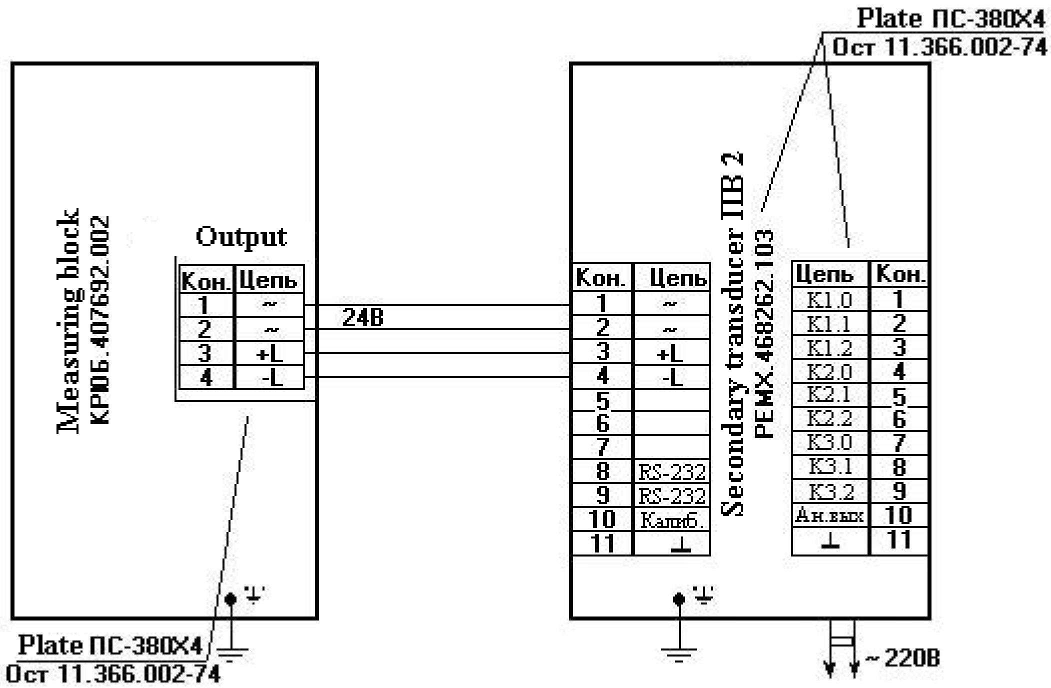


Fig. 2.90. Basic configuration interconnection diagram

ULM-11A1 level gage

ULM-11A1 level gauge (Fig.2.91, Table 2.20) is a non-contact radar device for continuous measurement. It is installed in the tank roof. It provides accurate filling level measurement (+3 mm) which is independent of product characteristics being measured and fluid medium in the tank (temperature, pressure, humidity, vapor and etc.).

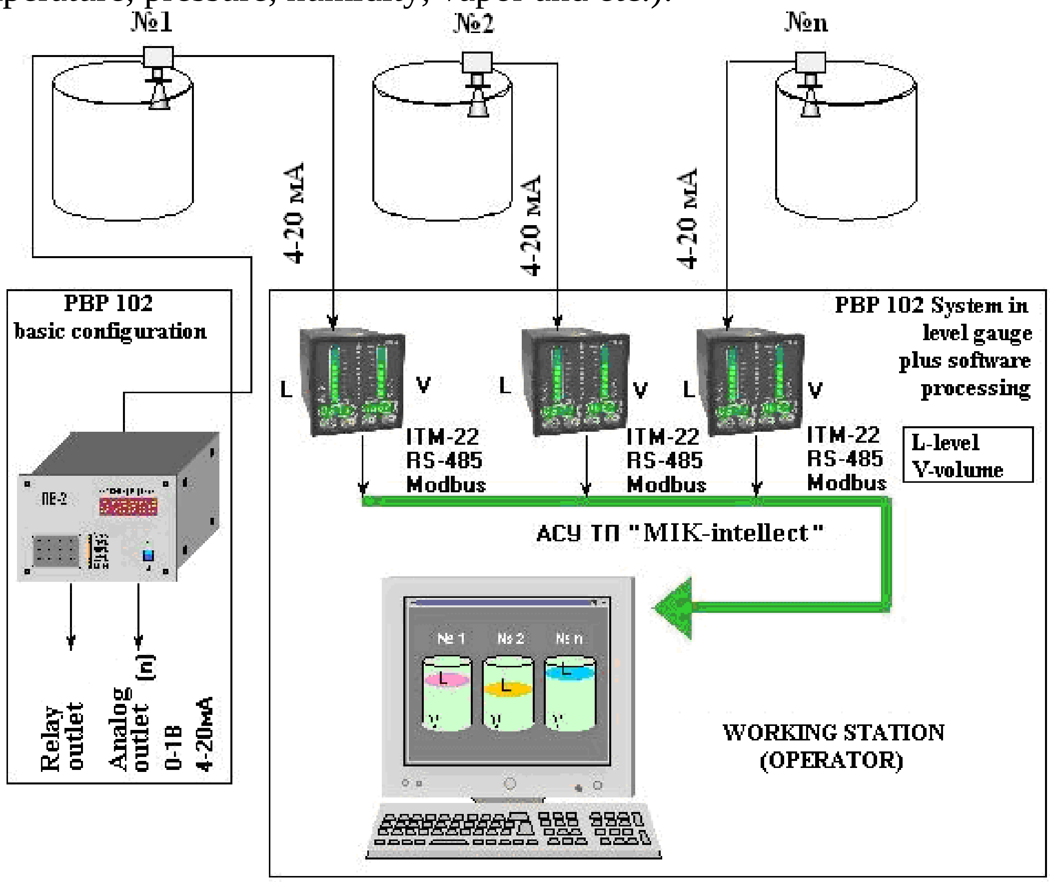


Fig. 2.91. Level measurement system configurations

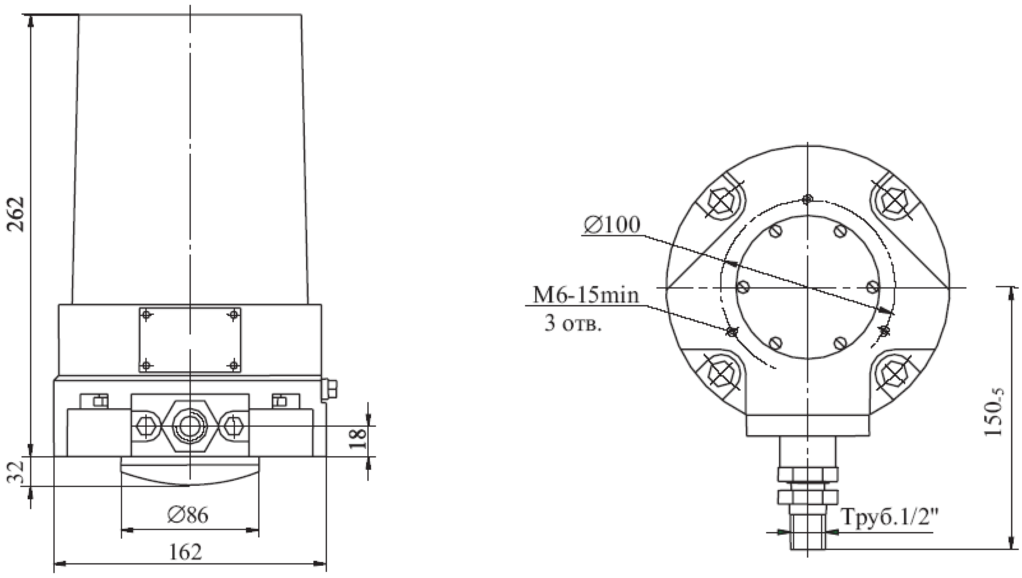


Fig. 2.92. УЛМ-11А1 level gauge overall and setting dimensions («LIMAKO», Tula)

ULM-11A1 level gages are based on linear frequency modulation commonly applied in high-frequency radar level gages intended for commercial applications. This method allows to implement spectral analysis in signal processing for effective ghost reflection suppression, as well as, interference suppression caused by the turbulence of the measuring fluid surface and clogging of the level gauge antenna.

ULM-11A1 level gauge (Fig. 2.92.) is an off-line measuring device with digital and proportional current interface. According to the set operation mode, the level gage measures the level, processes the signal and provides corresponding current signal.

Table 2.20

Technical characteristics ULM-11A1

Characteristics	Values
Measurement range	from 0,6 to 15 m
Maximum error	+3 mm within the measurement range
Temperature influence on the error	-
Measurement time	Not more than 0,6 sec
Measurement mode	continuous
Weight	8 kg
Ambient temperature	from -50 to +50 C
Atmosphere pressure	from 84,0 to 106,7 kPa
Line length	up to 2400 m

Digital interface corresponds to the RS485 standard. Software interaction is provided by Modbus protocol assistance. According to the protocols every level gauge is given a number which units up to 255 gauges into one measuring system.

Digital interface is applied both for level gauge configuration and accurate filling level readings. Due to this interface application, measurement results are read without losses in digital to analog to digital outlet signal conversion which are inevitable when only proportional current interface is applied.

Proportional current interface (Fig. 2.93) emits current signal ranging from 4 to 20 mA which is in proportion to the tank filling level. This interface is intended for connection with execution units (EU) level gage, indicators and etc. which current interface ranges from 4 to 20 mA.

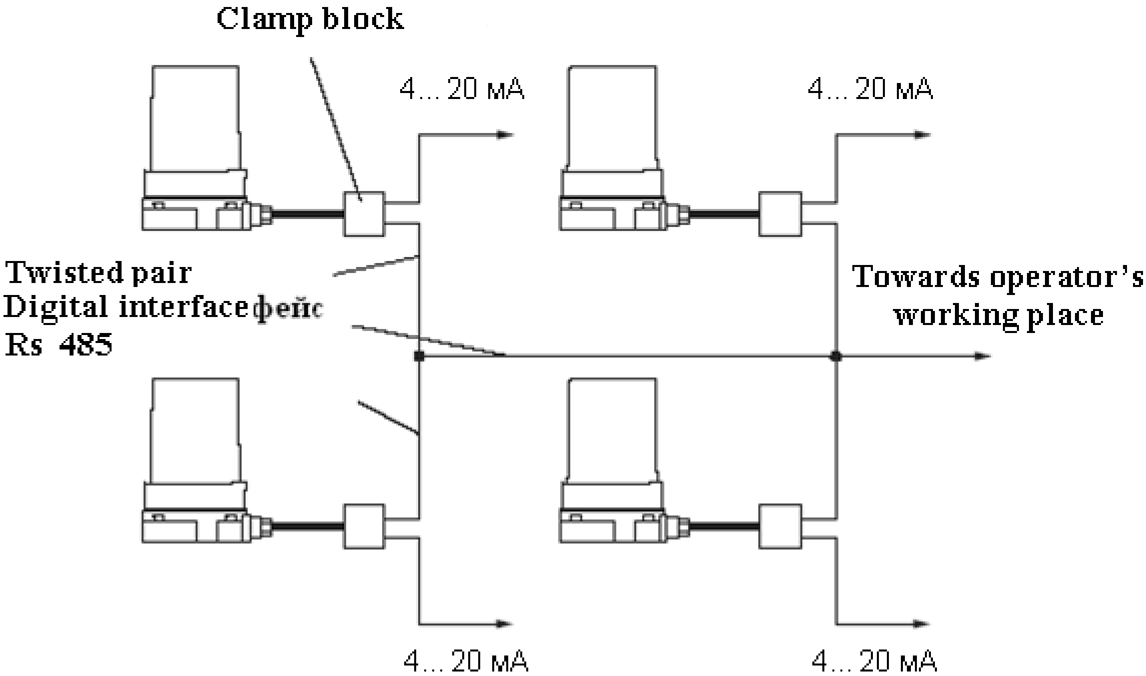


Fig. 2.93. ULM-11A1 level gauge proportional current interface

Electrical connections. It is recommended to connect the level gauge to the joint box by the control cable. Terminal blocks connected to the corresponding lines are under level gauge.

Due to high level gage response, rapid fluid level change can not cause failures in ULM-11A1 gage operation. When fluid surface is turbulent measurement accuracy is determined by the roughness type and force. A special signal processing algorithm is applied in agitator tanks. Foam influence can vary depending on its density and consistency; when product temperature is high, level gage is isolated from the tank internal volume by radio transparent pad.

Level gauges are mounted on any suitable flange by special reducing flange (Fig. 2.94).

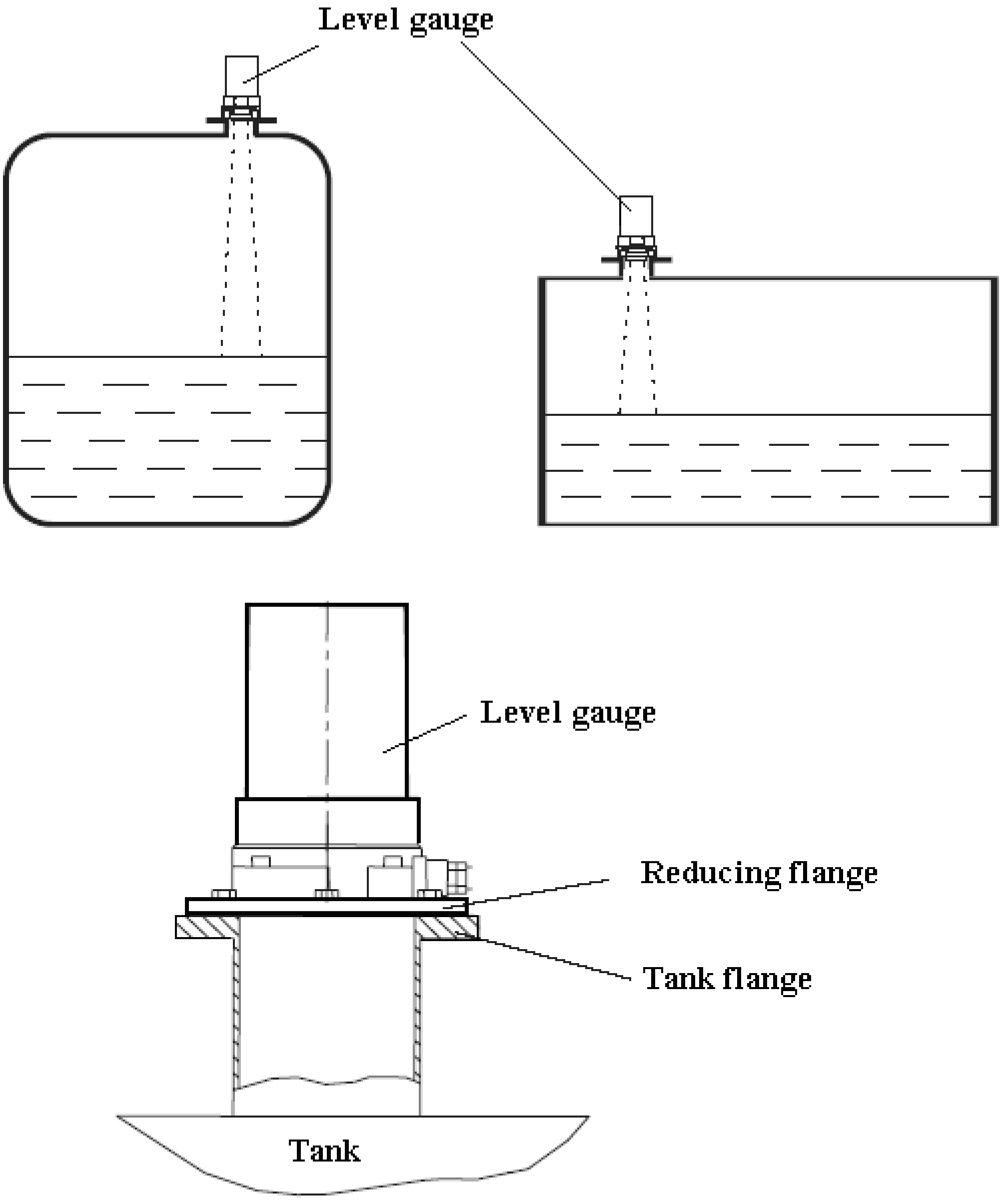


Fig. 2.94. ULM-11A1 level gauge installation on the tank

Radioactive level measurement. Nuclear and radioactive level gauges are based on the raying of the process fluid by nuclear radiation. Radiation gages typically are considered when nothing will work, or when the process penetration required by a traditional level gages present a risk because the liquids measured by nuclear gages are among the most dangerous, highly pressurized, rarefied, explosive, and aggressive. Radiation gages are also applied for filling level measurement when it is impossible to mount level gages or when expensive measuring systems are required because of tank construction peculiarities. It is preferable to apply nuclear gages when according to the safety standards it is forbidden to install level gages in the tanks or when the installation is not cost-effective. They are ideal for measuring highly adhesive fluids and for use in agitator tanks or in the tanks with high temperatures.

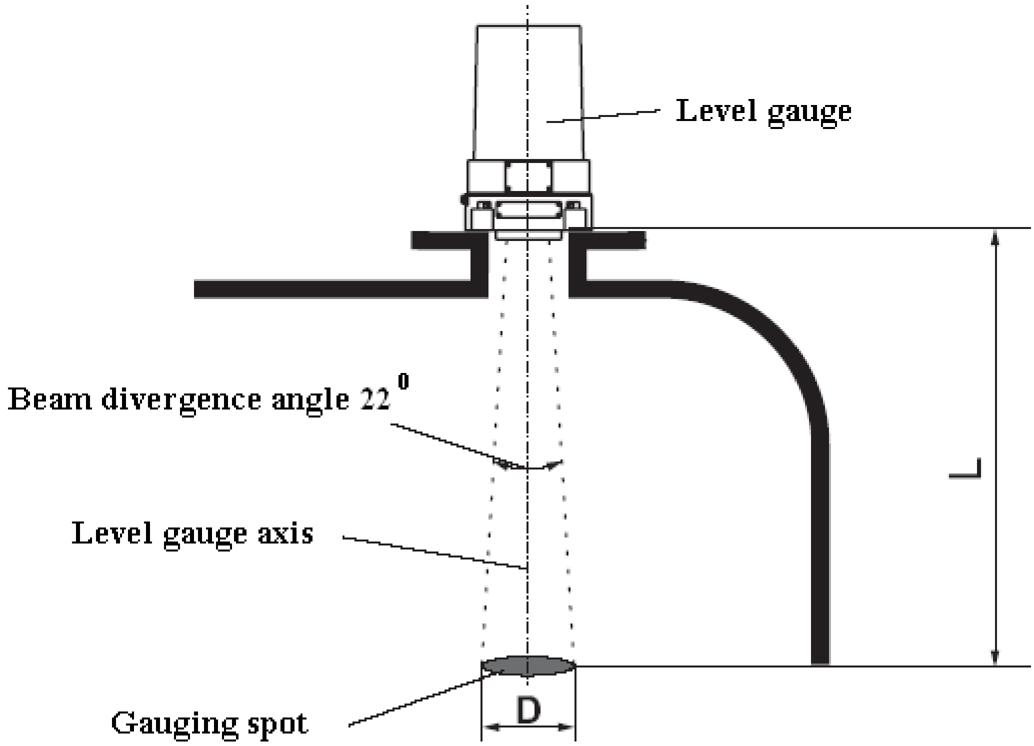


Fig. 2.95. ULM-11A1 level gauge divergence angle

Basic physics. Radioactive level measurement is based on the ability of artificial isotopes to pass through the process object in the tank losing some of their intensity. γ-ray bundle emitted by radiation source passes through the tank straight along the line (Fig. 2.96).

The receiver (***2)*** mounted on the tank wall which is opposite to the radiation source (***1)*** converts received rays into electrical impulses. As radioactive rays are absorbed by the object in the tank the radiation intensity depends on the level height (object thickness). The impulses formed by the receiver which frequency is proportional to the radiation intensity are transmitted to the switching device which

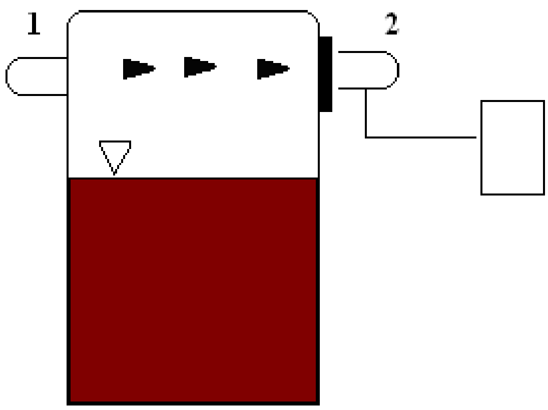


Fig. 2.96. Oil level radioactive measurement

responds when the impulse number drops to the minimum value. As in most cases, the thickness of the process material as high gamma rays are mainly applied. The tank walls which can be quite thick have significant influence on the measuring process. The original radiation intensity penetrating through the filled tank is calculated by the following equation:

$$I_1 = I_0 e^{-\mu(2kf + \rho_i d_i)}, \qquad (2.50)$$

where $\boldsymbol{f}$ *– tank wall thickness;*

$\boldsymbol{\rho_i}$ *– process fluid density;*

$\boldsymbol{d_i}$ *– tank inner diameter;*

$\boldsymbol{\mu}$ *– mass absorption factor;*

$\boldsymbol{k}$ *– wall material density.*

This equation can be applied for theoretical research when there are no walls, i.e. the thickness and density of the wall have no influence on the attenuation. However, this hydrocarbon level measurement has the following disadvantage. As most tank walls are metal and quite thick it leads to radiation scattering which influences its direction and intensity. As the result, the error can be up to 2%. For better accuracy, radioactive sources characterized by higher level energy are applied or the distance between the radiation source and receiver is decreased up to the minimum value that is not always possible in real tank farm operating conditions.

2.2.4. Automated integrated measurement systems for hydrocarbon level

Nowadays measuring systems, defining not only level parameters, but also other fluid characteristics, are widely applied both in Russia and abroad. Hydrostatic level measurement system (HLMS) for oil and petroleum product measuring is a good example.

«Struna-M» automated refined oil parameter measuring system (Fig. 2.97, 2.98, Table 2.21, 2.22, 2.23) applied during hydrocarbon gathering and storage, as well as, in tank park monitoring, provides non-commercial water alert, monitoring unit power circuit operation in accordance to environmental protection requirements.

Performance capabilities:

- Precise fuel parameter measurement (level, density, temperature);
- Volume and mass automatic calculation using calibration charts;
- Specific data records for each tank;
- Tank leakage automatic control;
- Fuel overflow control;
- Reading and calculated parameters display through off-line indicator or by standard interface;

- Non-commercial water alert;
- metrological certification without equipment dissembling.

Fig. 2.97. «Struna-M» level gauge
(«NOVINTECH», Korolev)

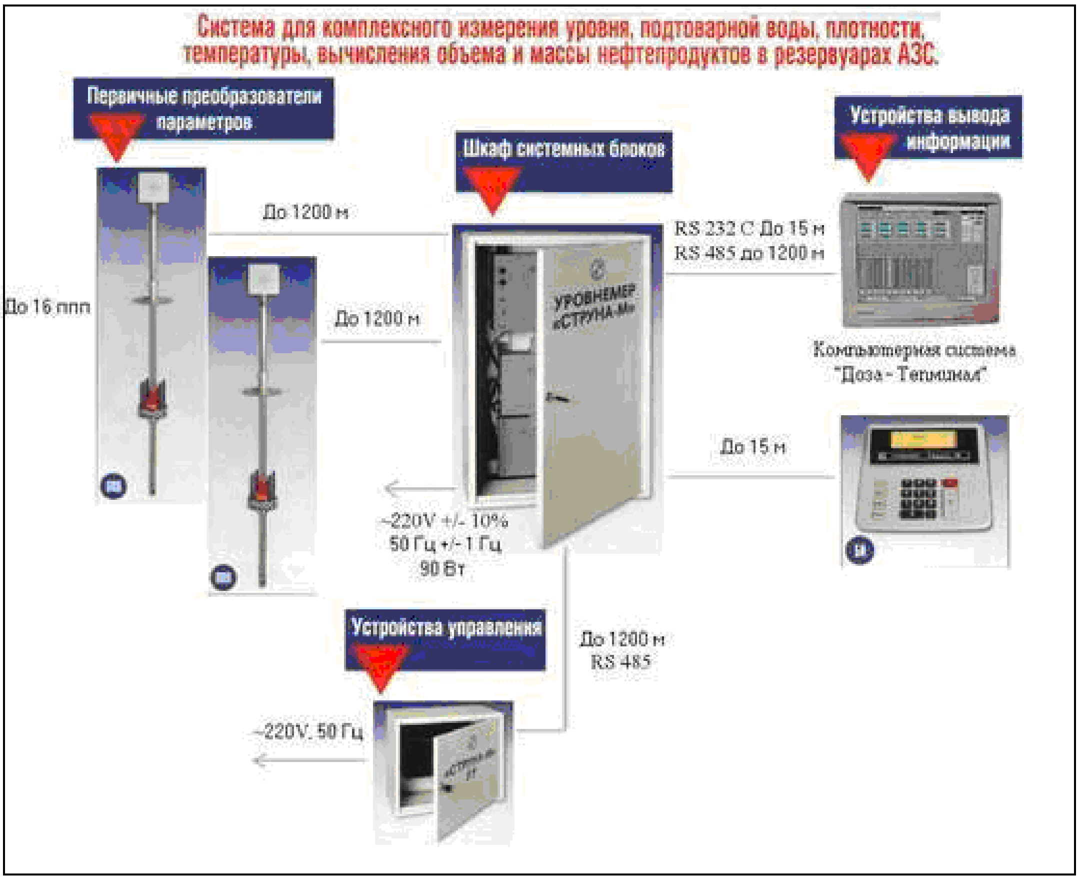


Fig. 2.98. «Struna-M» automated petroleum parameter measuring system

Table 2.21.

Technical characteristics of «Struna-M» level gauge

Characteristics	Values
Level measurement range (without density), mm	from 120 to 4000
Level measurement range (including density), mm	from 200 to 4000
Absolute level measurement error, mm	1, 0
Threshold response, mm	0, 2
Operation temperature range, °C	from - 40 to +50
Density measurement range kg/m³:	from 690 to 880
Absolute density measurement error, mm kg/m³	1,5
Non-commercial water alert at level, mm	25
Monitoring tank number	up to 16
Cable length from each tank to the control unit	not more 200m
Number of power circuit controlling outlets for each tank	up to 4
Power supply	220V +10-15% 50Hz, 0.6A

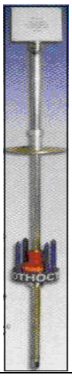
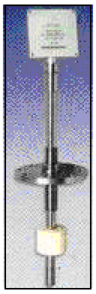
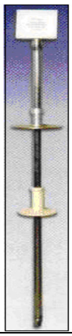
Table 2.22.

System unit technical characteristics

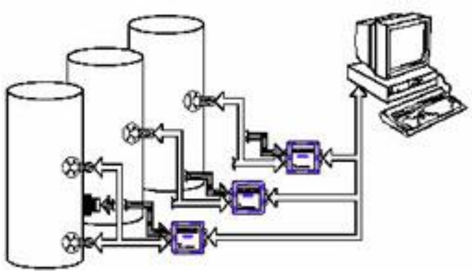
Computing unit	Supply unit	Indicator unit
Channel number, max: 16 Standard interface outlet RS - 232C, RS - 485 Outtype Dimensions (mm): 235x160x120	Power supply: 220V, 50Hz Power consumption: 90 Watt Dimensions (mm): 275x200x50	Desk-size, haracter-mode display: 2 lines per display Parameter setting – key-board Dimensions (mm): 195x180x50

Table 2.23

Technical characteristics of different transducers

Petroleum parameter primary transducer	Condensed gas parameter primary transducer	Metrological parameter primary transducer for tank calibration
		
Measuring level (mm):120 – 4000 Level measurement error (mm): ± 1.0 Sensitivity (mm): 0.02 Measuring density (kg/m^3): 650 – 1000 Density measurement error (kg/m^3): ± 1.5 Temperature measurement (C): -40 - +50 Temperature measurement error (C): ± 1.0 Temperature measurement resolution (C): 0,1 Non-commercial water alert (mm): 25	Measuring level (mm):100 – 4000 Level measurement error (mm): ± 1.0 Sensitivity (mm): 0.02 Working pressure (kg/m^3): 16 Condensed gas density from 480 kg/m^3	Measuring level (mm):10 – 4000 Level measuring error (mm): ± 1.0 Sensitivity (mm): 0.02

Hydrostatic level measurement system (HLMS) is intended for precise product level measurement in tanks of different configurations (Fig. 2.99, Table 2.24). Two high-precision transducers, temperature sensor, and transducer interface unit are mounted on the tanks.



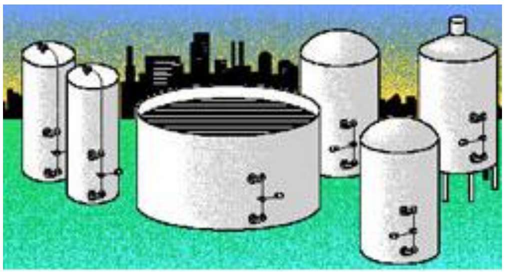


Fig. 2.99. Hydrostatic level measurement system

The main unit of the system is pressure transducer Sapphir-22MP or Sapphir-Kvarts. Based on high-precision pressure measurement, the system calculates such parameters as mass, density, volume, and tank filling level.

Table 2.24.

Hydrostatic level measurement system technical characteristics

Characteristics	Values
Serviced tank number	from 1 to 30
Mean lifetime	10 years
Line length between transducer interface unit and operator	not more 1500m
Ambient temperature for primary transducers and transducer interface units	from -50 to +50 ˚C
Ambient temperature for other components	from 5 to 50 ˚C

Transducer interface unit installed immediately near the tank receives the pressure transducer signals, calculates mass, density, volume and level values and indicates the measuring results in the fitted liquid-crystal display. At the same time, tank shell deformation caused by ambient temperature change is considered.

Upper level software provides:

- *high-precision level, density, mass and volume measurement;*
- *measurement results and calculation display*
- *data base maintenance (up to a year);*
- *product overflow prevention due to audible and visible alarms;*
- *current information and archive database printout.*

2.2.5. Flow meter and fluid, gas, vapor meter classification

The main types of flow meters and fluid, gas, and vapor meters are the following (Fig. 2.100).

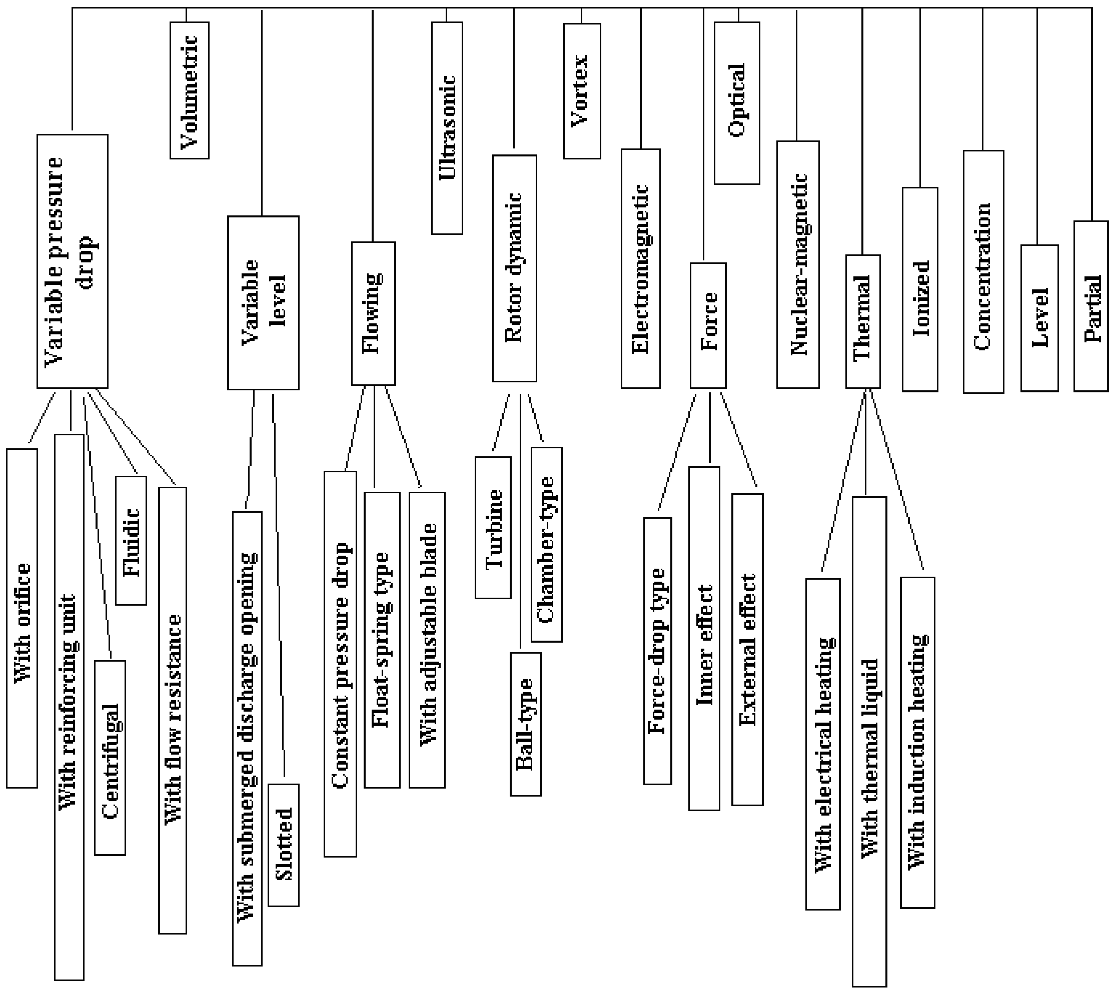


Fig. 2.100. Main flow meter and liquid, gas,

vapo meter classification

Based on the following principles, flow meters and fluid, gas and vapor meters can be divided into 4 classes:

Class A. Hydrodynamic principles: • *variable pressure drop; variable level; target; vortex; partial.* Differential pressure meter with orifice is one of the most commonly used *A class* devices. Rotameter and float-type devices classified as target meters are intended for low fluid and gas rate. Vortex flow meters are considered to be quite perspective.

•***Class B. Devices based on continuous moving part:*** *tachometer; force (including vibration).* Different types of *B class* tachometer flow meters including turbine, ball-in tube meters and chamber meters (i.e. rotary flow meter with oval gear and etc.) used as gas and petroleum meters are widely applied.

Class C. Different physical parameters: *thermal; electromagnetic; acoustic; optical; nuclear-magnetic; ionized.* The most widely applied *C class* devices are electromagnetic flow meters intended for measuring conducting liquid and ultrasonic flow meters (acoustic type) intended for liquid and gas measuring. Thermal and acoustic flow meters are rarely used for low liquid and gas rate measuring. Optical, magnetic resonance and ionization flow meter are rarely applied.

Class D. Specific principles: *correlated;level;concentration.* Level and concentration flow meters which belong to the fourth class are intended for one-time measurement, e.g. in industrial flow meter testing. Correlation devices are suitable for two-phase liquid flow rate measurement.

All flow meters and meters are part of the state device system which includes blocks, instruments and devices with standard inlet and outlet signal parameters, overall dimensions and port size, as well as power supply parameters. It is essential for industrial process monitoring, regulation and control. For the measurement of oil and gas mass and volume in trunk pipelines the following instruments are applied: thermometers, indicating and recording manometers for pressure measurement; gages for differential pressure monitoring in velocity-type flow meter; flow control devices (gas meters or flow meters).

Flow meter requirements

The flow meter requirements are the following:

- *measurement accuracy increase (most modern industrial processes, including petroleum product and gas selling require more accurate measurement);*
- *reading independence on medium parameter change: pressure, temperature, density;*
- *device reliability increase;*
- *device dynamic property improvement (dynamic flow measurement through industrial process velocity increase and flow meter application in automatic control system requires performance speed increase, i.e. dynamic property improvement: response time reduction, free frequency increase);*
- *wide measurement range; measured parameter range extension (measurement under high pressure or under pressure which is lower than atmosphere one, and wide temperature range)*
- *measured fluid wide nomenclature (sequential transportation of oil of different density and viscosity; two-phase and three-phase medium flow)*

Task and Discussion Questions

1. What are the main parameters defining volume and mass gas flow rate in pipeline orifice?
2. Explain why real incompressible flow rate in pipeline orifice is not equal theoretical one.
3. Compare dynamic, static and hydrostatic product mass measurement methods.
4. Provide the classification of differential manometers and describe the operation mode one of them.
5. Describe the design of thermoelectric transducer and its bonding technique in the pipeline.
6. What are the advantages of noncontact temperature measurement instruments?
7. Provide the classification and operation modes of acoustic level sensors.

3. HYDROCARBON FLOW RATE AND QUANTITY MEASUREMENT BY VARIABLE PRESSURE DIFFERENTIAL METHOD THROUGH ORIFICES AND DIFFERENTIAL PRESSURE GAUGES

3.1. Orifices

Flowmeters with orifices among other flowmeter devices (such as ultrasonic, turbine, inductive, vertical, etc.) are the most significant ones abroad and in our country as well.

The wide application of flowmeters with orifices is due to their low prices, simple design and practical operation at any pressure and temperature. Sample flowmeter units are not necessary in the calibration and testing of above-mentioned flowmeters, which is visa versa, in the case of the remaining flowrate devices and gas meters. Another advantage – convenient mass production, where the primary transducer (orifice) is hand-made, while remaining complex parts (devices to measure temperature, differential pressure, pressure and to process readings) are of large-scale production.

Orifices – an opening of a measured diameter that is used for measuring the flow of fluid through a pipe or for delivering a given amount of fluid through a fuel nozzle. In measuring the flow of fluid through a pipe, the orifice must be smaller diameter than the pipe diameter. [19].

Orifices are units with secondary transducers – differential pressure gauges.Differential pressure gauge readings (mechanical, electronic) are registrated and processed through planimeters or software programming, (Russia – VKG-2 (ВКГ-2); SPG-761(СПГ-761); SPG-763(СПГ-763); domestic and foreign - «Hyperflow», «Superflow» «Teleflow» etc.).

Planimeter – *(Latin «planum» flat place, plane and meter) an instrument for measuring the area of a plane figure.*

Regular circular charts are processed by proportional planimeters, irregular circular chart – radical planimeters, strip charts - polar planimeters. According to the results of diagram planimetry, the average daily gas flow rate is calculated:

$$Q = 0{,}1333 Q_{\max} N_k \, \varepsilon \sqrt{\frac{P}{Z\rho T}} K_f \,, \tag{3.1}$$

where 0,1333 –constant radical planimeter;

***Q_{max}** – upper level measurement of differential pressure gauge;*

***N_k** – planimetry number to radical planimetry reading;*

***ε** – correction factor, including expansion of measuring medium under operation conditions;*

***P** – absolute;*

***T** – absolute average daily gas temperature;*

***Z** – gas compressibility factor under operation conditions P and T;*

***ρ** – actual gas density;*

***K_f** – constancy for this orifice, determined by the calculations:*

$$K_f = \frac{1}{K_t \varepsilon_0} \sqrt{\frac{\rho_0 T_0 Z}{\rho_0}} \,, \tag{3.2}$$

*где **K_t** – where **K_t** –temperature expansion diagram factor (range from 20 to 60^o C K_t =1); **ε_0**;*

***ε_0** – correction calculation factor, including expansion of measuring medium under operation conditions ρ_0 and T_0;*

***ρ_0, T_0** and **P_0**– calculated gas density, temperature and pressure [25].*

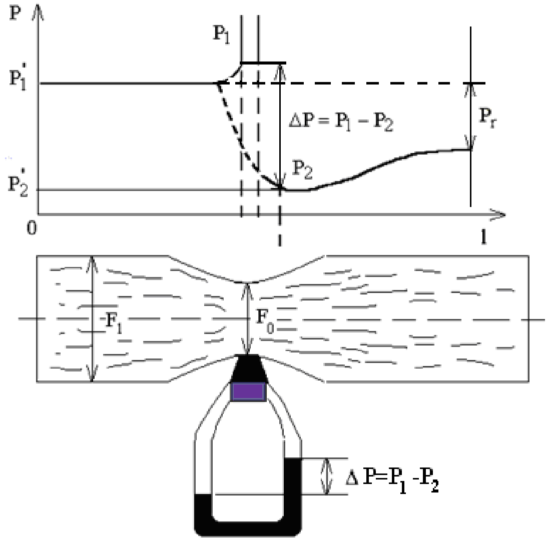
Design and selection of orifices is performed on the basis of given measured temperature and measurement condition, i.e ambient temperature, pipeline diameter, average and maximum flow, nominal pressure and pressure loss in an orifice. Calculations, based on the method of sequential approximation, determine the orifice type and diameter. The differential pressure gauge with corresponding measurement levels is selected according to chosen measured pressure difference value ***ΔP***.

Orifice is installed in the pipeline and produces local resistance, functioning as a primary transducer. Fluid flow velocity increases more in the orifice cross-section than before the orifice itself. Velocity increases thus, kinetic energy produces energy potential flow decrease in the orifice cross-section. Whereas, static pressure in the orifice cross-section is lower than the pressure before the orifice cross-section. Thus, the fluid flow through the orifice produces differential pressure $\Delta P = P_1 - P_2$ (Fig. 3.1), which depends on the flow velocity and fluid flow. Differential pressure ***ΔP*** measures the flow rate in the pipeline.

Interstate regulation documents ***GOST 8.586.1-2005; 8.586.5-2005***, adopted on January 1, 2007 [19–23], established the standard orifices which determine fluid and gas flow and volume measurements. The following orifices are widely applied:

- *standard differential pressure gauges (Fig. 3.1, 3.4);*

- *nozzle (Fig.3.2);*
- *venturi nozzle (Fig. 3.3, 3.8);*
- *venture tube (Fig. 3.9).*



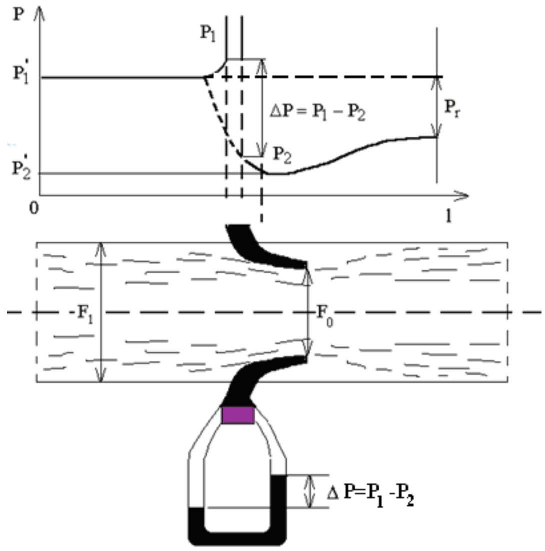


Fig. 3.1 Differential pressure gauge *Fig. 3.2 Nozzle*

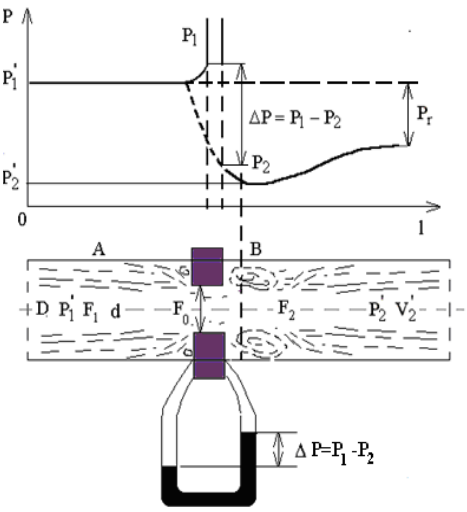


Fig. 3.3. Venturi nozzle

Orifices are applied only if fluid flow is steady or changes slowly in time. Flow pulsation can be under the following conditions [18]:

$$\frac{\left[\frac{1}{n}\sum_{i=1}^{n}\left(\Delta P_i - \overline{\Delta P}\right)^2\right]^{0,5}}{\overline{\Delta P}}, \tag{3.3}$$

where, ***n*** *– measurement number of differential pressure in time interval which determines flow pulsation;*

i *– measurement number;*

ΔP_i *– differential pressure value in orifice at* i *-m measurement;*
$\overline{\Delta P}$ *– average differential pressure value in orifice ;*

$$\overline{\Delta P} = \frac{1}{n}\sum_{i=1}^{n}\Delta P_i \,. \qquad (3.4)$$

3.1.1. Diaphragm

Diaphragm *– a sensing element consisting of a thin, usually circular, plate that is deformed by pressure applied across the plate.* (Fig. 3.4).

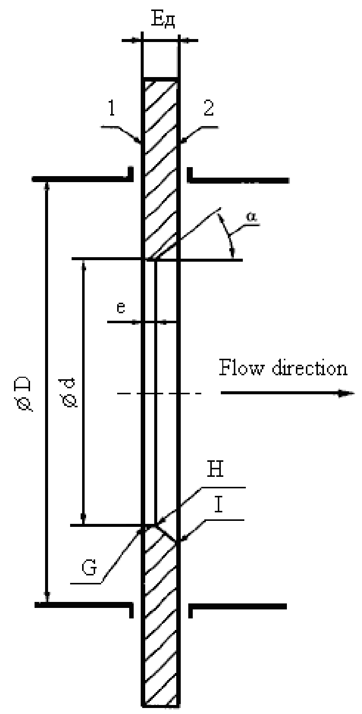


Fig. 3.4. Diaphragm: 1 – input threshold(face); 2 – output threshold (face); ЕД – diaphragm thickness; e –cylindrical section length of diaphragm; G, H, I — edges; d-orifice diameter; D – flow area diameter of pipeline; α – dip angle formed by cone to diaphragm axis (within 45° ± 15°)

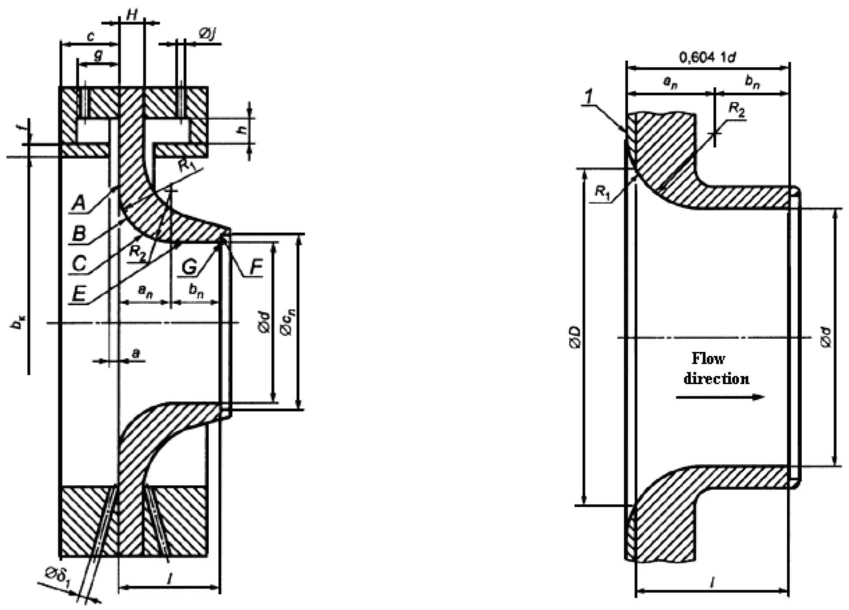
According to [GOST8.586.2-2005]:

- *cylindrical section length of diaphragm e ranges from 0,005 to 0,02 flow area diameter* ***D****;*
- *difference between values e should not be more than 0,001* ***D*** *if measured in any point on the orifice contour;*
- *diaphragm thickness* ***Е_Д*** *ranges from e to 0,05* ***D****;*
- *diaphragm diameter* ***d*** *is not less than 12,5mm;*
- *inlet edge* ***G*** *should be sharp as its curve radius should not be more than 0.05mm;*
- *dip angle formed by cone* ***α*** *to diaphragm axis should range from 45° ± 15°.*

3.1.2. Nozzles

***Nozzle** –a standard orifice type, a passageway at the inlet to the outlet-throat.*

According to GOST ***8.586.3-2005***, there are two types of nozzles: nozzle ISA 1932 and ellipse nozzle. *Nozzle ISA 1932*- the passageway at the inlet is formed by the arcs of two radii connected at a tangent (Fig.3.5).



a) b)

Fig.3.5. Nozzle ISA 1932 cross-section shows throat axis in different orifice diameter correlations (d)and internal pipeline diameter (D):

a) – при $d \le 2D/3$ *; b) – при* $d > 2D/3$

***Orifice diameter** – the diameter with minimum cross-section area (GOST **8.586.1-2005**).*

Nozzle profile is:

- *input face plane **A**,perpendicular to nozzle axis line;*
- *nozzle orifice plane, forming a line of circle arcs **B** and **C**;*
- *internal cylindrical throat surface **E**;*
- *internal circular flange surface **F**, preventing damage of external outlet edge **G** ;*
- *nozzle wall thickness **H**.*

Inlet face plane ***A*** is restricted to periphery diameter ***1,5 d*** and diameter ***D*** (***d*** – orifice diameter under ambient operation temperature; ***D*** – internal pipeline diameter). If d **≤ *2D/3*** then radial width of inlet face plane equals zero (0) (Fig. 3.5,a). If ***d >2D/3*** nozzle has no plane within internal periphery pipeline diameter. In this case, the nozzle is manufactured as if ***D*** is more than***1,5 d***, then nozzle section is cut off so that the flat nozzle face has an internal diameter equaling ***D*** (Fig. 3.5, b). All nozzle parameters are determined according to GOST ***8.586.3-2005.***

Ellipsis nozzle – a *standard orifice type, a passageway at the inlet where radial profile cross-section is 1\4 ellipsis* (Fig. 3.6, Fig. 3.7).

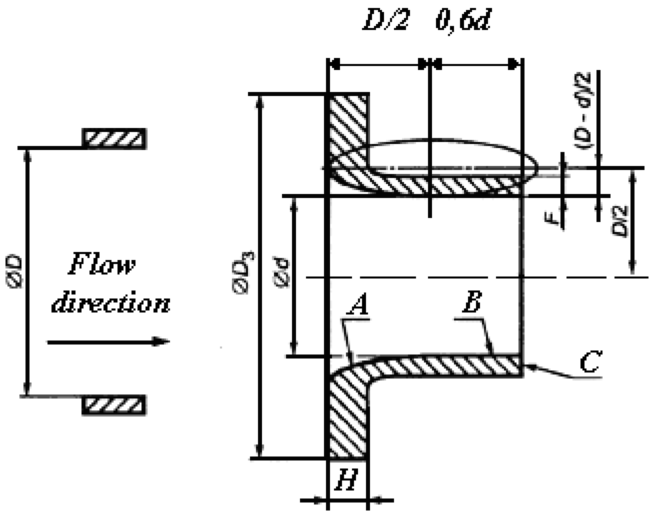


Fig. 3.6. Ellipsis nozzle profile with rather large throat diameter (0,25 ≤ β ≤ 0,8): where β – relative orifice diameter, determined as the ratio of orifice diameter under ambient operation temperature d to internal pipeline diameter D.

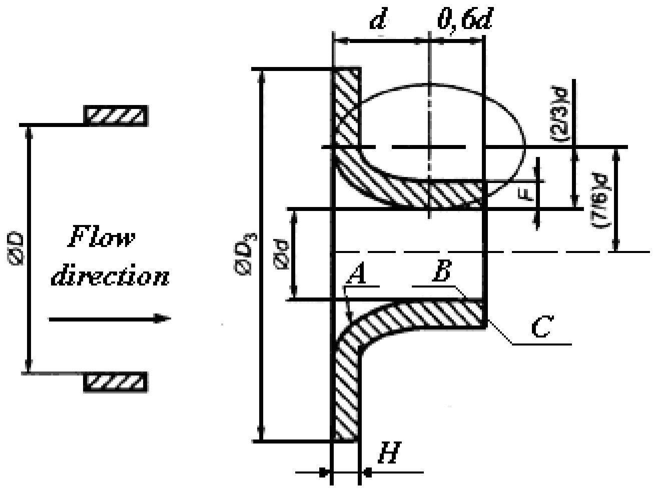


Fig. 3.7. Ellipsis nozzle profile with rather large throat diameter (0,25 ≤ β ≤ 0,8)

Nozzle profile is: orifice section ***A***; internal cylindrical throat surface ***B***; outlet face nozzle surface ***C***. Internal contour of nozzle orifice section ***A*** in the axis cross-section has an arc form « 1\4 ellipsis «. Ellipsis nozzle profile of relative large and small throat diameter is:

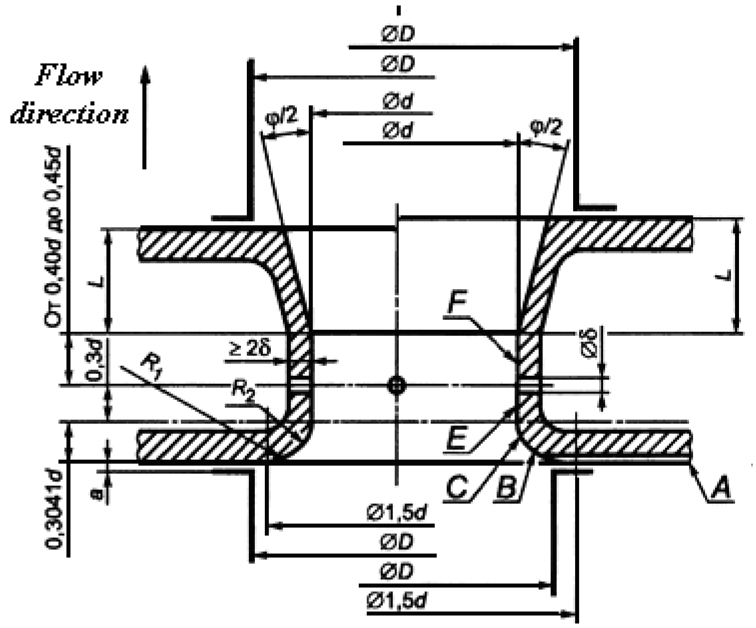
- *nozzle orifice section **A**;*
- *internal cylindrical throat surface **B**;*

- *outlet nozzle face surface **C***

Ellipsis centre is located ***D/2*** from the nozzle axis. Large ellipsis radius is parallel to nozzle axis and equals ***D/2***. Small ellipsis radius equals ***(D - d)/2***. Throat ***B*** has diameter ***d*** and length ***0,6 d***. Thickness ***H*** should be not less than 3 mm and not more than ***0,15 D***. Throat wall thickness ***F*** should be not less than 3 mm if ***D > 0,065 м***. If ***D ≤ 0,065 м***, then ***F*** should be not less than 2 mm but sufficient to prevent nozzle deformation.

3.1.3. Venturi nozzle

***Venturi nozzle** – a nozzle that, because of the venturi effect (the drop in pressure resulting from the increased velocity of a fluid as it flows through a constricted section of a pipe)increases the velocity of a fluid flowing through it. The nozzle includes inlet section as nozzle ISA 1932, throat and outlet section as divergent cone (diffuser)* [Fig. 3.8].



a) *b*)

Fig. 3.8. Venturi nozzle:

a) –truncated nozzle at d ≤ 2D/3; b) – non-truncated nozzle at d > 2D/3:

Venturi nozzle includes inlet face surface, perpendicular to nozzle axis line, orifice section with rounded profile, cylindrical throat and diffuser.

Inlet face surface and orifice section of venture nozzle is similar to face surface and nozzle orifice section of nozzle ISA 1932. Inlet face plane ***A*** is constricted to periphery diameters ***1,5d*** and diameter ***D***. If ***d = 2D/3*** radial width of this flat nozzle plane equals zero (0). If ***d > 2D/3,*** nozzle has no flat section within the periphery diameter ***D***. In this case, the nozzle is manufactured as if ***D*** is more than ***1,5 d***, then nozzle section is cut off so that the flat nozzle face has an internal diameter equaling ***D***. Diffuser (Fig. 3.8) should be connected to throat section ***F*** without radial interface. All burrs should be eliminated. Diffuser obliquity angle φ should be less than 30°.

Venturi nozzle can be truncated (Fig. 3.8, a). Outlet diffuser diameter of venture nozzles are less than **D**. Diffuser can be truncated up to 35% of its length.

3.1.4. Venturi tubes

Venturi tube *–a short tube with a calibrated constriction that is used in instruments or devices, developed to take advantage of the principle that a fluid flowing through a constriction has increased velocity and reduced pressure.A standard orifice that includes inlet cylindrical section, convergent cone section (convergent tube) throat and divergent cone section (diffuser).*

Cross-section of venture tube through its axis is depicted in Fig. 3.9.

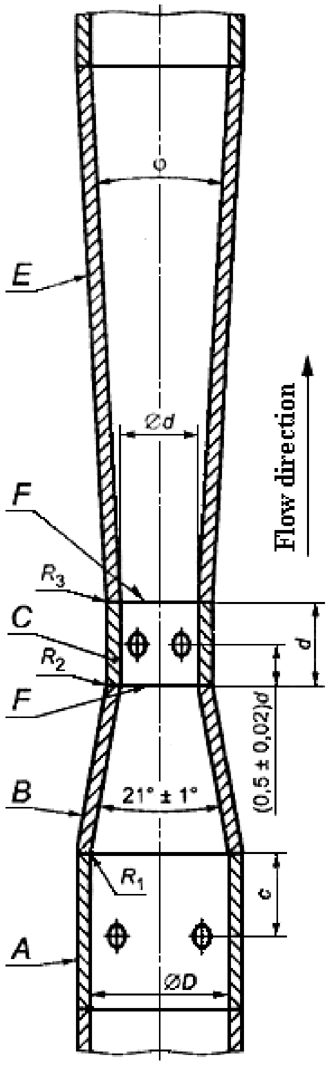


Fig. 3.9. Geometrical profile of venture tube

Venturi tube includes inlet cylindrical section ***A***, orifice cone section ***B***, cylindrical throat ***C*** and diffuser ***E***. Diffuser ***E*** should have angle φ ranging from 7° to 15°. Internal surface of venture tube is cylindrical and concentric to the pipeline axis.

Conical orifice section ***B*** for venture tube has cone angle 21°±1°. This section is constricted at the inlet by a plane, intersecting surfaces ***B*** and ***A***; at the outlet – by a plane intersecting surfaces ***B*** and ***C***.

Total conical orifice section length ***B***, measured parallel to venture tube axis, approximately equals ***2,7 (D-d).*** The point where the conical orifice section ***B*** passes to inlet cylindrical section ***A*** is radius $\boldsymbol{R_1}$, which depends on different venture tubes.

Venturi tube is called «truncated» tube if the outlet diffuser diameter is less than diameter D. Diffuser can be truncated up to 35% of its length.

Based on the manufacture specification, venturi tubes are divided into the following types:

- *tubes with (without treatment) cast inlet conical section;*
- *tubes with treated inlet conical section;*
- *tubes with welded inlet conical section of sheet steel.*

Venturi tube with cast inlet conical section is manufactured according to GOST ***8.586.4-2005***, i.e. cast in a sand mold or other methods. Tube throat is treated, while the run between conical and cylindrical units is rounded. This venture tube is applied under the following conditions:

- *pipeline diameter* $0{,}10м \le D \le 0{,}80м$;
- *relative orifice diameter* $0{,}30 \le \beta \le 0{,}75$;
- *Reynold number* $Re \ge 4{\cdot}10^4$.

Venturi tubes with treated inlet conical section are cast**.** Inlet conical section, throat and inlet cylindrical section are treated. The run between conical and cylindrical units can be rounded or not. This tube is applied under the following conditions:

- *pipeline diameter* $0{,}05м \le D \le 0{,}25м$;
- *relative orifice diameter* $0{,}40 \le \beta \le 0{,}75$;
- *Reynold number* $4{\cdot}10^4{\cdot}\beta \le Re \le 10^8{\cdot}\beta$.

Venturi tubes with welded inlet conical section of sheet steel are applied in pipelines with large and small diameters**.** This venture tube is applied under the following conditions:

- *pipeline diameter* $0{,}20м \le D \le 1{,}20м$;e
- *relative orifice diameter* $0{,}40 \le \beta \le 0{,}70$;
- *Reynold number* $\cdot Re \le 4{\cdot}10^4$.

3.1.5. Quality Characteristics of Orifices

Quality characteristics are considered in selecting the orifice types. According to Table 3.1, diaphragm is applied in measuring fluid flow and quantity in pipelines with internal diameters of more than 100mm.

Nozzle ISA 1932 is applied under the following conditions – stable characteristics during long-term performance. Nozzle ISA 1932 provides exact measurements in pipelines with small diameters.

Venturi nozzle is recommended in those cases, where flowmeter performance reliability and low pressure loss in pipeline systems is necessary. Venturi tubes are recommended to measure contaminated flow rate; in short linear pipeline areas before and after the orifice, under reliability conditions and low pressure loss.

General advantages: Simple design of flow transducer; possible monitoring of spill-free method i.e. no flowmeter testing. This is due to the fact that there is complete scientific-technological information, including standard information of above-mentioned measurement method.

Disadvantages: small measurement range (not more than 1:3, as mentioned earlier, at present – increased up to 1:10, due to multi-level "smart" pressure detector (transducer); high sensitivity to irregular flow velocity curves at the orifice outlet, due to wall friction in inlet \or and outlet pipelines (shutoff valves, elbows, etc.). Under such conditions, there should be linear pipeline sections with given diameter less than 10 before above-mentioned orifices (*Dy*); and sometimes, up to *50Dy* or more (installation of orifice after wall friction devices).

Table 3.1

Quality Characteristics of Orifices

<table>
<tr><td rowspan="2">Orifice type</td><td colspan="2">Orifice Characteristics</td></tr>
<tr><td>Advantages</td><td>Disadvantages</td></tr>
<tr><td>Diaphragm</td><td>• simple production and installation, wide application within a wide Re number range;
• installed in pipelines with internal diameter from 50 to 1000 mm;
• indefinite expiration factor is less than in other orifices;
• small condensate quantity practically does not influence the expiration factor.</td><td>• inlet diaphragm edge dulls during performance, resulting in additional indefinite progressive expiration factor which could significantly affect the diaphragm in pipelines with diameters less than 100 mm;
• pressure loss on the diaphragm is more than in other orifices.</td></tr>
<tr><td>Nozzle ISA 1932</td><td>• stable characteristics under long-term performance, pressure loss is less than on the diaphragm;
• relative orifice diameter (up to 0,8);
• diaphragm reacts less to turbulent flow pulsation;
• less sensitivity to the internal pipeline wall roughness;
• internal pipeline diameter less than 100mm provides uncertainty results in fluid flow measurement than in the diaphragm, where the diaphragm inlet edge dulls due to no corrections.</td><td>• complex in production;
• applied only in pipelines with internal diameter not more than 500 mm;
• no experimental data at Re $>10^7$.</td></tr>
<tr><td>Ellipsis nozzle</td><td>• stable characteristics under long-term performance;
• pressure loss is less than on the diaphragm;
• relative orifice diameter up to 0.8.</td><td>• complex production;
• applied only in pipelines with internal diameter not more than 630 mm;
• no experimental data at Re $>10^7$.</td></tr>
</table>

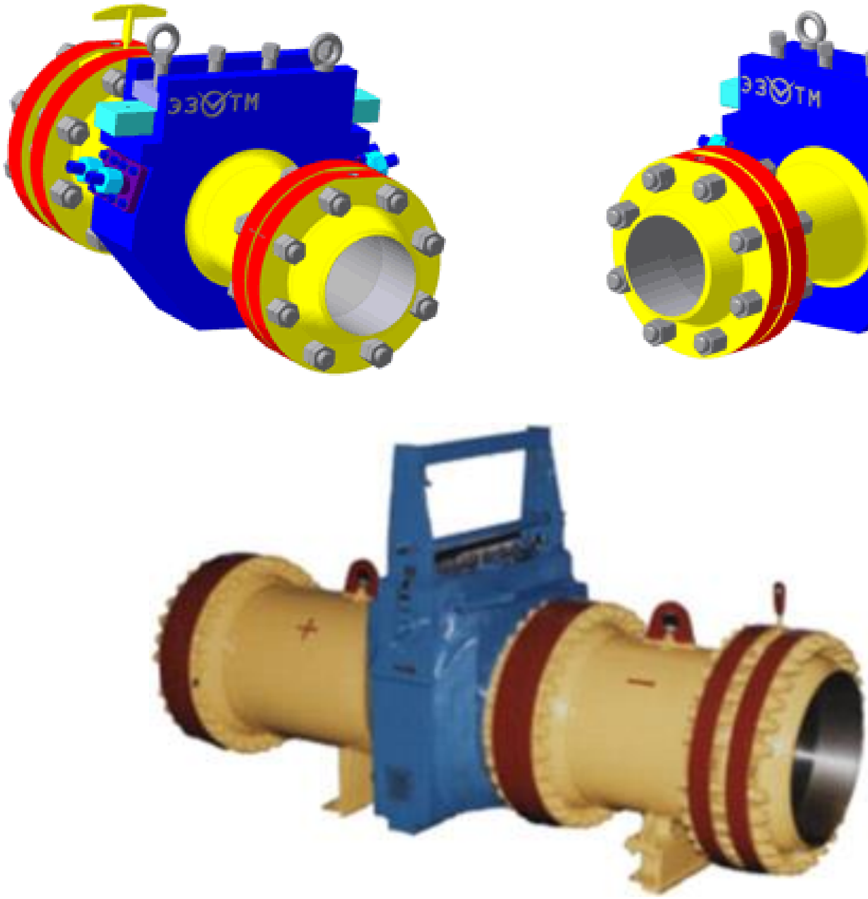
1	2	3
Venturi nozzle	• stable characteristics under long-term performance of flowmeter; • pressure loss less significant than on the diaphragm, nozzle ISA 1932 and ellipsis nozzle; • outlet flow coefficient inde-pendent of Re number.	• complex production; • narrow application range to Re numbers.
Venturi tube	• stable characteristics under long-term performance ; • pressure loss less significant than on the diaphragm, nozzle and sometimes even venture nozzle; • applied in short linear pipeline areas; • no stagnant zones in flowing (circulating) sections, where deposits could accumulate; • applied in pipelines with inter-nal diameter up to 1200 mm.	• complex production; • large sizes.

3.1.6. Orifice examples

Quick-change orifice QCO

Quick-change orifice (QCO) (Fig. 3.10, Table. 3.2, 3.3), are for gas flow measurement stations on pipelines and includes the following property- reversible gas flow direction. The following QCO types: ***Dy*** (given diameter) 80, 100, 150, 200, 300, 350, 400, 500, 700 under pressure 7,5 MPa и 16 MPa according to GOST ***8.563.1-97***.are produced at the Joint Stock Company «ЭЗТМ».

Sophisticated domestic QCO are designed as compacted diaphragm and frame. Reliable compacted U-shaped diaphragm profile guarantees compacted diaphragm units, which, in its turn, provides stable differential pressure at the inlet and outlet of the gas flow.



a)

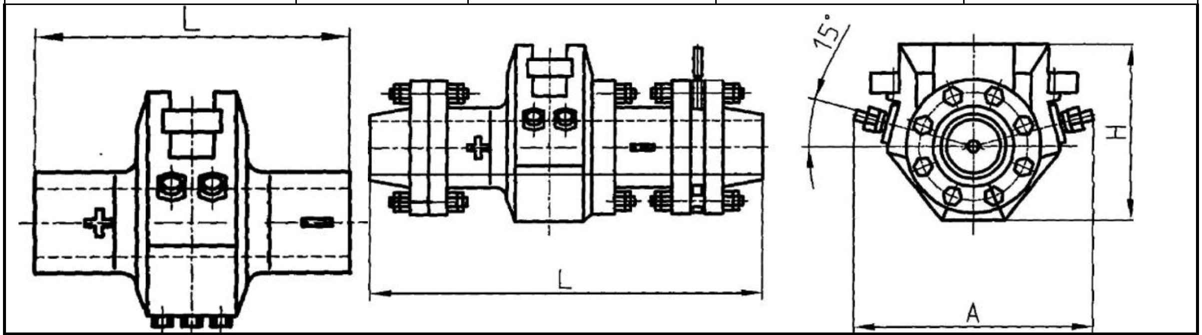
b)

Fig. 3.10. Quick-change orifice: a) mating collar (flange)and welded without hoisting unit of small sizes up to Dy 300 to measure gas flow in municipal and separate enterprise pipelines; b) mating collar (flange)and welded with hoisting unit of small sizes up to Dy 300 to measure gas flow in municipal and separate enterprise pipelines.

Table 3.2

Technical characteristics of QCO (Dy 80-200**)**

Parameters	QCO type			
Internal diameter, mm	Dy 80 (QCO 80/7.5)	Dy 100 (QCO 100/7,5)	Dy 150 (QCO 150/7,5)	Dy 200 (QCO 200/7,5)
	80	100	150	200



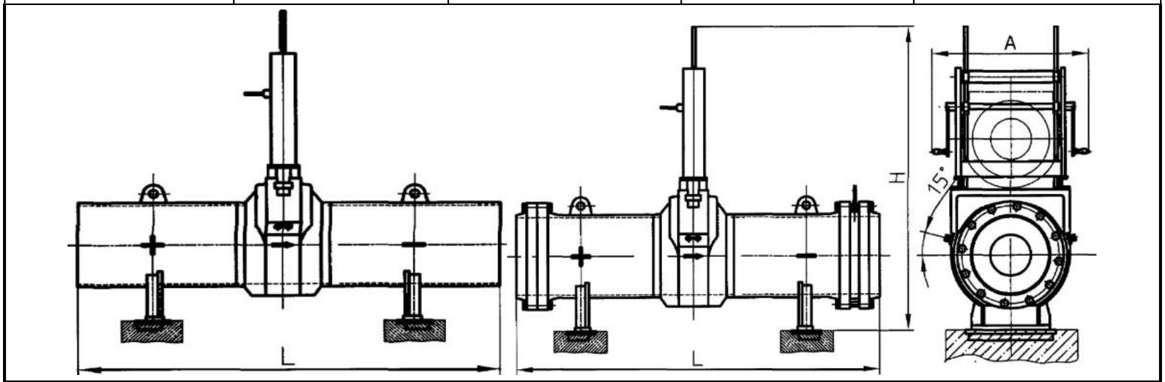
Operation pressure, MPa	7,5			
Changing time for diaphragm, min, (not more)	20			
Operation temperature, °C	Up to - 55			
Sizes, mm				
Collars:				
Length, L Width, A Height, H Weight, kg	530 375 225 70	650 440 320 150	850 500 380 260	1115 3530 440 290
Welded collars:				
Length, L Width, A Height, H Weight, kg	330 375 225 50	410 440 320 100	610 500 380 180	330 530 440 200

Exact precision in installing diaphragm center to QCO axis in comparison to GOST ***8.563.1-97*** requirements provides steady gas flow through orifice, and thus, increases the flow measurement accuracy. The advantage of such QCO – the orifice is a pressure tap, dipping to the orifice axis and providing condensate flow during high moisture gas transportation. This new technology guarantees precise production of such orifices and exact distance between diaphragm face and orifice axis.

Table 3.3

Technical characteristics of QCO (Du 300-700)

Parameters	QCO type			
Internal diameter, mm	Dy 300 (QCO 300/7.5)	Dy 400 (QCO 400/7,5)	Dy 500 (QCO 500/7,5)	Dy 700 (QCO 700/7,5)
	300	400	500	700



Operation pressure, MPa	7,5			
Changing time for diaphragm, min, (not more)	20			
Operation temperature,°C	Up to - 55			
Sizes, mm				
Collars:				
Length, L Width, A Height, H Weight, kg	1520 810 1020 790	1900 940 1720 1700	2440 1040 2020 2280	3240 1260 2435 4050
Welded collars:				
Length, L Width, A Height, H Weight, kg	1210 810 1020 550	1610 940 1720 1200	2010 1040 2020 1600	2810 1260 2435 2480

QCO collar design provides reliable seal orifice connection with the pipeline. The device design to unclamp pipelines during dismantling of the whole measurement unit is simple and convenient. Operation QCO temperature is up to - 55°C.

QCO includes:

- *detachable conduits, providing examination and internal pipeline inspection without QCO dismantling;*
- *double contour compaction to exclude gas leakage into the atmosphere;*
- *easy hoisting unit for the diaphragm (for Dy 300 mm or more), for its quick changing in 20 min*.

All above-mentioned QCO are designed and manufactured to provide full safety for the operator during its performance, repairing and inspection. Every quick-change orifice undergoes thorough and complete acceptance testing on special stands under specific pressure, which is 1.5 higher than operating pressure.

Simple design provides easy performance during inspection or changing of diaphragm, maximum operation safety, measurement precision and economic.

Quick-change orifice –type US and US-F

Quick-change orifice – type US and US-F are produced in Joint Stock Company «Potenchial». The diaphragms are directly installed in the collars with circular cells. The internal device diameter values (D20) and diaphragms (d20) are designed according to technical requirements.

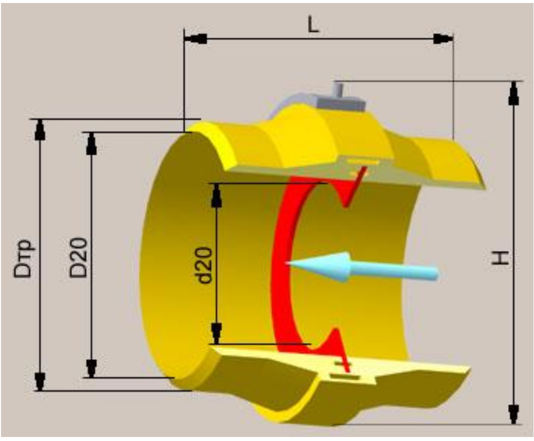


Fig. 3.11. Quick-change orifice – type УС

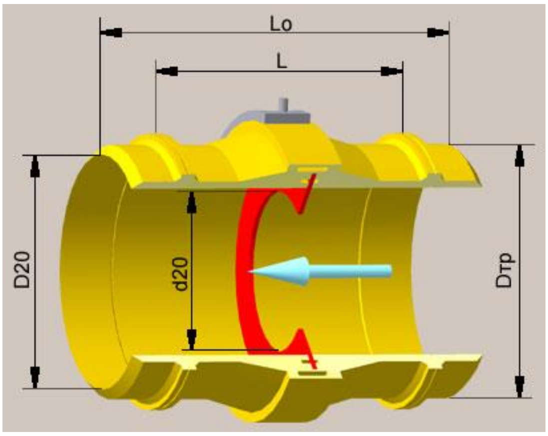


Fig. 3.12. Quick-change orifice – type УС-Ф

Orifice – type US is installed in the pipeline by welding (Fig. 3.11, Table 3.4). US-F is installed in the pipeline by collars and remote collar (Fig. 3.12, Table 3.4).

The above-mentioned plant produces 8 type-size orifices US and 6 type-size orifices US-F which are installed in pipelines with internal diameter of 50 ÷ 500 mm under technical requirements TU U 05755855.009-2001 «Orifices», as well as, diaphragms – type DB according to TU U 05755585.008-2001 «Quick-change Diaphragms ».

Table 3.4

Technical characteristics of orifices –type УС, УС-Ф

Orifice type	Size, mm			Weight, kg
	$D_{тр}$	H	L	
1	2	3	4	5
Orifices- type УС				
US-6,3-50 UHL1	57	260	375	20
US-6,3-80 UHL1	89	280	390	28
US-6,3-100 UHL1	114	318	505	35
US-6,3-150 UHL1	159	360	743	50
УС-6,3-200 UHL1	219	440	928	95
US-6,3-300 UHL1	325	554	1384	234
US-6,3-400 UHL1	426	737	1819	535
US-6,3-500 UHL1	530	868	2303	755

Orifice –type УС-Ф					
US-Ф-6,3-100 UHL1	114	318	505	827	65
US-Ф-6,3-150 УХЛ1	159	360	743	1107	93
УС-Ф-6,3-200 UHL1	219	440	928	1341	176
US-Ф-6,3-300 UHL1	325	554	1384	2016	430
US-Ф-6,3-400 UHL1	426	737	1819	2514	990

Technical characteristics of УС, УС-Ф	
Parameters	Value
Operation pressure in flow, not more than , Mpa	6,3
Maximum differential pressure in flow, Mpa	0,16
Operation temperature range in flow, °C	–30…+50
Operation ambient temperature range, °C	–30…+40

3.1.7. Measurement of gas physico-chemical parameters and differential pressure in orifices

Variable flow and fluid parameters are measured to determine fluid volume and flow. Gas density, medium temperature, viscosity and adiabat coefficient are determined under standard conditions; in the case of flow and gas volume measurement, density is measured under standard conditions. Fluid physical properties can be determined through direct or indirect (calculation/estimation) method, based on reference data (GOST ***8.566***).

Additional information about thermal-physical parameters of measured flow is applied in the calculation method. In one-phase flow- temperature and pressure are measured; in multi-phase flow- its composition, sometimes density under standard conditions are measured.

Fluid density, adiabat coefficient and fluid viscosity are determined for conditions (temperature and pressure) in the orifice plane to measure the static pressure before the orifice.

Therefore, complete monitoring device system is installed to measure physico-chemical gas parameters, which is called ***«Measuring-calculating System (MCS)***. What devices are in the system (Fig. 3.13) depends on the measured fluid and methods measuring or calculating its density and viscosity.

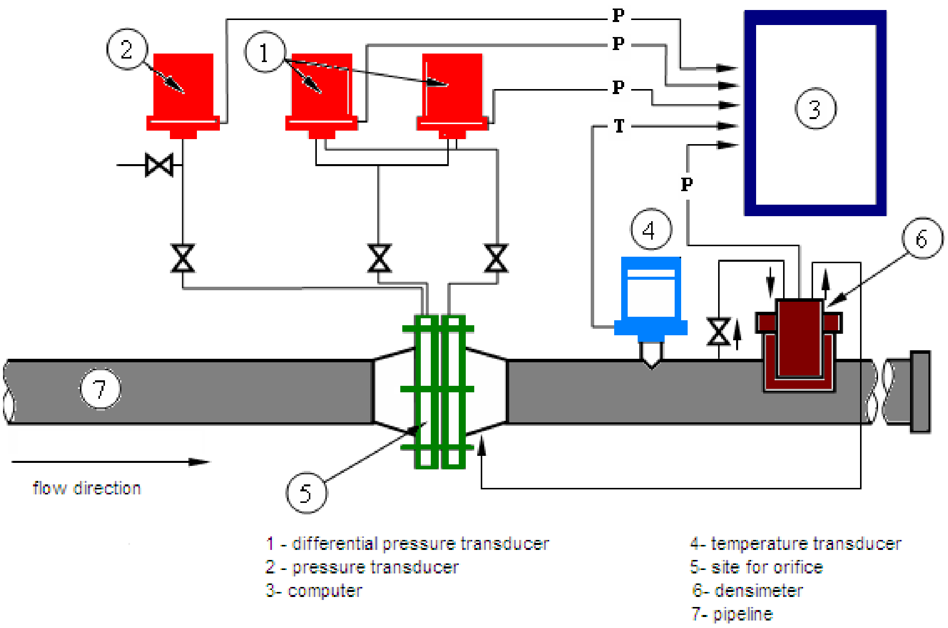


Fig. 3.13 Measuring system

If the composition of one-phase flow and multi-phase flow has given-constant value, it can be measured in the above-mentioned system.

During the installation of secondary flow parameter measurement device, it is necessary to pay attention to the following technical requirements [24]:

- *no stress in the devices and vibration tolerance;*
- *under climatic conditions that can cause significant faults, these devices are installed in special chambers to control the temperature;*

- *install secondary devices from primary transducers according to allowable telecommunication distance requirements.*

Gas density: to calculate flow output, information about the density in the pipeline cross-section before the orifices is necessary, as here, density selection for differential pressure measurement is conducted.

According to GOST ***30319.0-96*** [27] gas density (gas mixture) - *mass or weight of a substance per unit volume.*

Flow density is measured by stream densimeters or densimeters (a device that measures the specific gravity or relative gravity of a gas, liquid or solid) or flow parameter measurement depending on selected calculating method and flow type. Density determined by flow measurement sample analysis is conducted according to GOST ***18917 - 82*** and GOST ***14921 -78*** [28,29].

Samples can be applied for density measurement with further correction to the conditions before the orifice or for flow composition analysis which is applied in calculating methods to determine density.

When measuring multi- component flow, the composition of which changes during the measurement process, it is necessary to consider the fact that the density measurement method based on sample selection needs evaluation of additional faults, as the measured flow composition is considered as a given constant parameter.The lower the stated fault, the more sample selection frequency. Stream densimeters are installed if the flow composition drastically changes and is random (in the case of measuring gas condensate or associated gas output).

The following methods are applied in calculating fluid and gas density:

- *density calculation based on state equation;*
- *density calculation where density is at zero excess pressure and fixed temperature with correction in volume expansion and compressibility.*

According to GOST **(ГОСТ)** 30319.0-96, the state equation of gas is the interrelation of compressibility factor, temperature and given molecular mass of the components. (State equation is a mathematical expression that defines the physical state of a substance by relating volume to pressure and absolute temperature for a given mass of the material).

In the norms, the state equation is expressed as following:

$$Z = 1 + A_0, \qquad (3.5)$$

where, $\boldsymbol{A_0}$ *–function of relative density(*$\boldsymbol{\theta=\rho/\rho_{кр}}$*) and temperature (*$\boldsymbol{\tau=T/T_{кр}}$*);*
$\boldsymbol{\rho_{кр}}$ *and* $\boldsymbol{T_{кр}}$ *–critical density and temperature parameters (tabular values).*

In terms of given density, the equation (3.5) can be written as follows:

$$\pi = \frac{\tau\theta}{Z_{кр}}\left(1 + A_0\right), \tag{3.6}$$

where $\boldsymbol{\pi = P/P_{кр}}$.

If compressibility coefficient is known, then density is:

$$\rho = \frac{10^3 MP}{RTZ}, \tag{3.7}$$

*where **M** – mole mass (kg\kmol);*

***P** – absolute pressure(MPa);*

***R** – universal gas constant, equal to 8,31451 kJoule/kmolК;*

***T** – temperature (К);*

***Z** – compressibility factor*

$$\rho = \frac{\rho_c P T_c}{P_c T K}, \tag{3.8}$$

where, $\boldsymbol{K = Z/Z_c}$ *gas compressibility coefficient (gas mixture) – ratio of compressibility factor under operation conditions to compressibility factor under standard conditions (calculated according to GOST 8.586.1-5-2005);*

***c** – index indicating that the parameters are calculated under standard conditions* (Table. 3.5).

Table 3.5

Physico-chemical characteristics of natural gas
(GOST 30319.0-3-96)

Gas	Chemical formula	Molar mass M_i kg/kmol	Density ρ_{ci} kg/m^3
Methane	16,043	0,6682	0,9981
Ethane	30,070	1,2601	0,9920
Propane	44,097	1,8641	0,9834
н-Butane	58,123	2,4956	0,9682
и-Butane	58,123	2,488	0,971
н-Pentane	72,150	3,174	0,945
и-Pentane	72,150	3,147	0,953
н-Hexane	86,177	3,898	0,919
н-Heptane	100,204	4,755	0,876
н-Octane	114,231	5,812	0,817

Acetylene	26,038	1,090	0,993
Ethylene	28,054	1,1733	0,9940
Propylene	42,081	1,776	0,985
Hydrogen	2,0159	0,08375	1,0006
Aqueous vapor	18,0153	0,787	0,952
Hydrogen sulphide	34,082	1,4311	0,990
Methyl -mercaptan	48,109	2,045	0,978
Sulfur dioxide	64,065	2,718	0,980
Helium	4,0026	0,16631	1,0005
Neon	20,1797	0,8385	1,0005
Argon	39,948	1,6618	0,9993
Carbon monoxide	28,010	1,1649	0,9996
Nitrogen	28,0135	1,16490	0,9997
Oxygen	31,9988	1,20445	0,9993
Carbon dioxide	44,010	1,8393	0,9947

Determination of wet gas density and the dry gas portion density in wet gas is necessary in measuring the volume and output of wet gas.We can write wet gas density as

$$\rho_{â.ã} = \rho_{ñ.ã} + \varphi \rho_{â.ï_{\max}} , \tag{3.9}$$

where, φ - relative wet gas.

Dry-part gas density in wet gas is defined by

$$\rho_{ñ.ã} = \rho_{ñ} \frac{Ò_{ñ}\left(Ð - \varphi Ð_{â.ï_{\max}} \right)}{P_c Ò Ê} . \tag{3.10}$$

If operating gas temperature T is not higher than saturated water vapor temperature $T_{satr,}$ respectively operating pressure P, then density of maximum water vapor density $P_{wv\ \max.}$ equals saturated water vapor density p_{sv}, where pressure $\rho_{wv\ \max.}$ is saturated vapor pressure.

If operating temperature T is higher than saturated water vapor temperature T_{sat}, respectively operating pressure P, then density $\rho_{wv\ \max}$ equals heated water vapor density ρ, where $P_{wv\ \max}$ is gas density$P$.

Wet gas compressibility coefficient in determining dry gas portion density in wet gas can be calculated excluding wet gas density.

Gas density measurement by densimeters can be applied in that case if the flow structure does not change. Location for gas sample selecting is in the upper section of the horizontal pipeline under the following conditions:

- *flow velocity > zero;*

- *no turbulence.*

Densimeters are installed before or after the orifice. The distance between the orifice and densimeter is determined according to GOST ***8.586.5-2005*** [23].

Fluid density variation is monitored, creating a flow through the sensitive densimeter unit as a lateral total flow. (Fig. 3.14).

Fluid density value is given by

$$\rho = \frac{\rho_0 P T_\rho}{P_\rho T} = \rho_0 \left(\frac{P}{P - \Delta P_\rho} \right) \left(\frac{T - \Delta T_\rho}{T} \right), \tag{3.11}$$

where $\boldsymbol{\rho_0}$ *– densimeter index;*

$\boldsymbol{P_\rho}$ *– gas pressure in sensitive densimeter unit, Pa;*

$\boldsymbol{\Delta P_\rho}$ *–pressure difference in the pressure selection location before the orifice and in the sensitive densimeter unit, Pa;*

$\boldsymbol{\Delta T_\rho}$ *–gas temperature in sensitive densimeter unit, K;*

$\boldsymbol{\Delta T_\rho}$ *– temperature difference in the pressure selection location before the orifice and in the sensitive densimeter unit, K.*

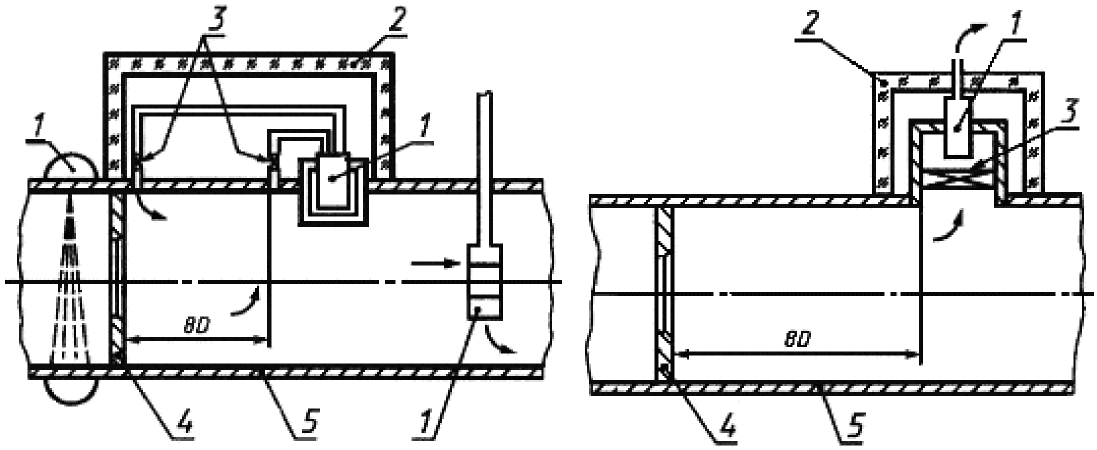


Fig. 3.14. Densimeter unit: 1 - densimeter; 2 – thermal insulation; 3– valve; 4 - orifice; 5 – pipe

The indirect method includes fluid value parameters for calculation to determine the density under operating conditions. For example, gas density under operating conditions can be determined by their densities under standard conditions, pressure and temperature (for gas mixtures- component composition is included, according to GOST ***30319.1***), as well as, pressure and temperature values.

Density under standard conditions can be determined by bottle method, according to GOST ***17310***.

Density measurement frequency under standard conditions is based on the ambiguous measurement results and possible density value changes in a given time interval (day, month). Number of measurements in a given time interval is defined by

$$n = 1 + \exp\left\{\frac{CZ}{2B} + \sqrt{\left(\frac{CZ}{2B}\right)^2 + \frac{(Z - A)}{B}}\right\}, \tag{3.12}$$

where, ***n*** *–necessary number of samples;*

$\boldsymbol{Z} = 2ln\left(S \big/ U\rho_i\right)$;

A= *–8,04445;*

B *= 2,50960;*

C *= 2,82837;*

$\boldsymbol{U\rho_c}$ *– ambiguous measurement result* ρ_c*;*

S *– estimation of mean-square measurement result divergence* ρ_c*, defined as*

$$S = \sqrt{\frac{\sum_{i=1}^{m}\rho^2{}_{c_i} - \frac{1}{m}\left(\sum_{i=1}^{m}\rho_{c_i}\right)^2}{m-1}}, \tag{3.13}$$

where, ***m*** – number of samples *($m \geq 4$),equal to the number of samples in a given time interval;*

$\boldsymbol{\rho_{ci}}$ *– density value under standard conditions based on the analysis result of i samples*

Physic-chemical gas parameters include component composition and transported hydrocarbon moisture. To determine component composition, any chromatograph that doesn't alter the fluid composition is applied. Component composition is determined according to GOST requirements ***23781*** and GOST ***10679.*** To determine gas moisture any (drymeter) moisture indicator is applied which measures condensate vapor moisture temperature (dew-point temperature), mass or volume content of water vapors in a unit of gas mass. Natural gas moisture is determined according to GOST requirements ***20060***. These characteristics determine natural gas quality factors [20-23].

Temperature of measured fluid is necessary to determine fluid density and viscosity, to calculate orifice diameter and internal pipeline diameter under operating temperature. If the measured medium is gas, then the temperature value is applied for adiabat coefficient calculations.

In determining parameters and their calculation methods sometimes temperature measurements in °C and\or K are necessary. To measure substance mass or volume in average flow parameters in a given time interval, there is a temperature detector with special units to record the measurement results and their integration, i.e. such units as temperature transducer and thermometer which measure and record temperature. Recording, integrating and archiving tools to measure temperature are analogously to pressure measurement tools.

To determine the physical fluid properties information of flow temperature in the pipeline cross-section, which is for differential pressure selection in the orifice, is necessary. Temperature measurement in the pipeline cross-section is practically impossible, due to the fact that if a sensitive thermometer unit is installed in this cross-section, the flow velocity distribution would be distorted and consequently, the outflow coefficient would also change.

Due to the fact that there is no equal temperature in the pipeline, there could be additional measurement faults if the temperature measurement point is moved from the orifice. Thus, in selecting the temperature measurement point, it is necessary to exclude the affect of the thermometer liner on the flow structure before the flowmeter and provide a small temperature difference in the cross-section (i.e. the section for pressure selection and its measurement). The precise selection of the distance from the orifice to the temperature measurement point depends on the following requirements: external thermometer liner diameter, flowmeter performance conditions, pipeline insulation, flow regime and measured fluid parameters. To select the optimal installation location for the thermometer liner according to the above-mentioned factors is rather a complex problem and requires special analysis. The following recommendations provide practical fault assumption in the temperature measurement.

Fluid temperature is measured before or after the orifice in the pipeline through temperature measurement transducer or thermometer, installed radially in the pipeline (Fig. 3.15). There should be no local resistance between the orifice and thermometer liner. If the measured medium temperature is less than 120 ^{0}C, then the sensitive thermometer unit submerges to ***D*** depth ***(0,3-0,7).***

According to GOST ***6651-94*** [12] the following definitions are considered:

Length of external thermometer section – *the distance from the bearing fixed connecting pipe (collar) plane to the connector end.*

Length of submerged thermometer section – *the distance from the running end of the shielding fitting to possible operating location under upper interval temperature measurement.*

Measured temperature range – *temperature interval for the thermometer*.

The most suitable location for the installation of the temperature transducer and thermometer or its protective liner (if necessary) is depicted in Fig. 3.15, a.

Possible location inclination are depicted in Fig. 3.15, b, Fig. 3.15, d, or installation after the orifice in the elbow as depicted in Fig. 3.15, c. Recommended flow direction is depicted in Fig. 3.15 b, c –

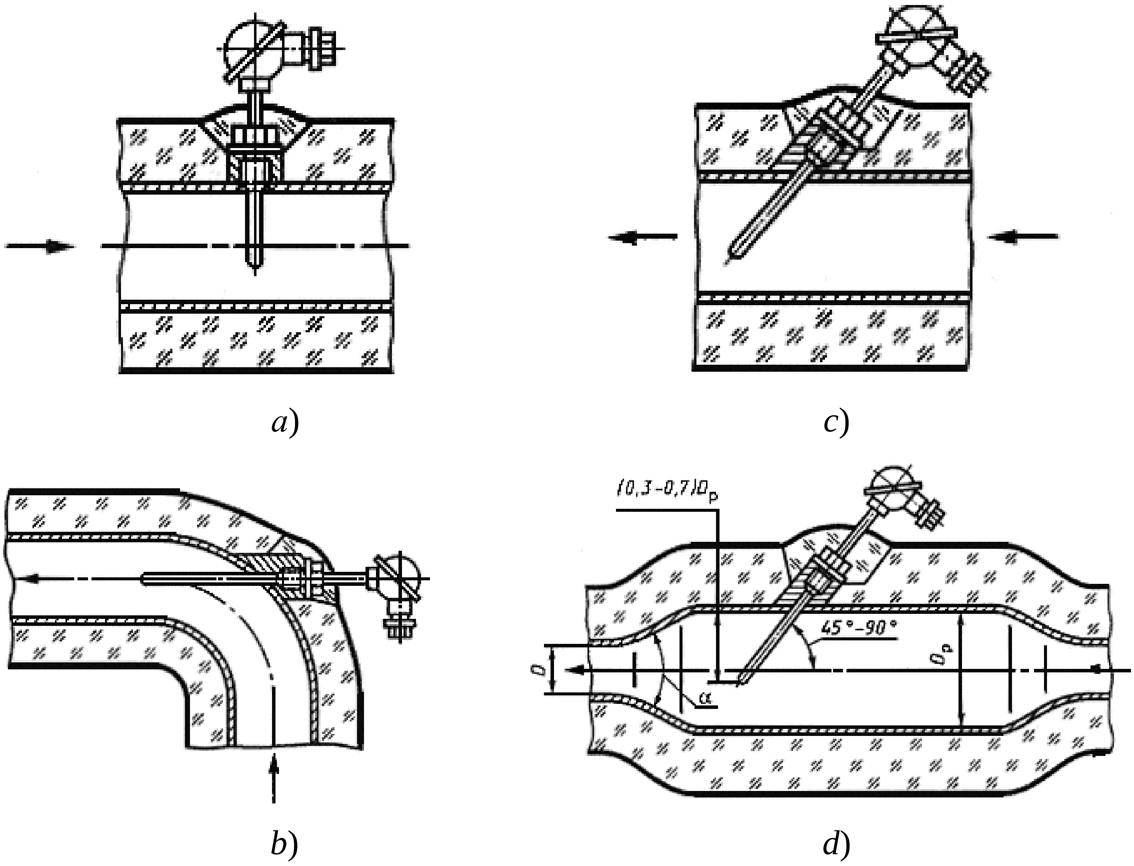


Fig 3.15. Temperature transducer unit or thermometer in pipeline:
D – pipeline diameter;
Dp –expanded pipeline diameter;
α –divergence angle, determined according to the values in Table 3.6

Divergence angle value *α*, provides steady fluid flow in the diffuser (Table 3.6).

Table 3.6

Divergence angle value α*,*
providing steady fluid flow in the diffuser

$(D_p/D)^2$	1,5	2	2,5	3	3,5	4
α	28°	22°	16°	12°	9°	6°

If the fluid – gas, under conditions that there is a great pressure loss ($\Delta\omega > 1{,}6 \cdot 10^5$ Pa), then the temperature in the orifice is calculated in two ways: before the orifice- measured temperature or after the orifice- according to the following formula

$$T = T_2 + \mu_{JT}\Delta\omega \, , \tag{3.14}$$

*where, **T_2** – measured temperature after the orifice, K;*

$\Delta\omega$ – pressure loss in the orifice,

μ_{JT} – Joule-Thompson coefficient, *K/Pa*

$$\Delta\omega = \left(1 - \beta^{1,9}\right)\Delta P \, , \tag{3.15}$$

*where, **ΔP** – differential pressure on the orifice,Pa;*

***β** – relative orifice diameter.*

$$\mu_{JT} = \left.\frac{\partial T}{\partial P}\right|_{H} \text{ or } \mu_{JT} = \frac{RT^2}{MPC_p}\left.\frac{\partial Z}{\partial T}\right|_{P}, \tag{3.16}$$

*where, **H** – enthalpy, Joule/mole;*

***M** – gas mole mass, kg/mole;*

***P** – fluid pressure, Pa;*

***C_p** – specific heat at constant pressure, Joule/(kg·K);*

***T** – absolute (thermodynamic) fluid temperature, K;*

***R** – universal gas constant R = 8,31451, Joule /(mole·K);*

***Z** – factor or compressibility coefficient Z=1.*

Determination of fluid viscosity. Fluid (dynamic) viscosity value is applied in the calculation of Re number, which affects the orifice efflux coefficient. Fluid viscosity can be measured by viscosimeter (flowmeter), calculated by empirical \ theoretical equations or graph-analytic method.

Dynamic viscosity (internal friction) [27] – a measure of the internal friction or the resistance of a fluid to flow (Resistance is brought about by the internal friction resulting from the combined effects of cohesion and adhesion). Quantitative viscosity is determined by tangential force per unit of the shifting layer area to maintain constant flow velocity relative to the shear (shift) and which equals 1.

Viscosity depends on pressure and temperature. Gas viscosity increases as temperature increases, while liquid viscosity- quickly decreases.

Gas viscosity in several Pa is constant, while liquid viscosity increases as pressure increases. Modern devices to measure viscosity include errors within 1 to 6%.

***Adiabatic coefficient** is thermodynamic parameter of a gas medium (i.e. gas or gas mixture), occurring without heat exchange (a gain or loss of heat).*

***Determination of adiabatic gas coefficient** (isentropic curve) ratio of relative pressure change respectively to relative gas density change **without** heat exchange (a gain or loss of heat).*

Calculation method is applied to determine adiabatic coefficient

$$k = \frac{\rho}{P}\frac{\partial P}{\partial \rho}\bigg|_S . \tag{3.17}$$

In determining gas outflow, the adiabatic coefficient errors are insignificant. Thus, for example, error in determining adiabatic coefficient is 5% and results in additional outflow error if about 1% (*ΔP/P=0,25* и *β=0,75*). If the value ***β*** and ratio ***ΔP/P*** decrease, then adiabatic coefficient fault in comparison to outflow error is less significant.

The calculations can be done according to the following equation GOST ***8.586.1-2005*** (3.15) if there are no adiabatic coefficient value data:

$$k = \frac{\tilde{N}_{\eth}}{\tilde{N}_V}, \tag{3.18}$$

where, ***Cp*** , ***C_V*** – specific heat *(P and V=const)*

Absolute measured fluid pressure is for calculating physical properties (parameters) of measured fluid (medium) – density, adiabatic gas coefficient. Absolute pressure is necessary in measuring gas to monitor its conditions

$$\frac{\Delta P}{P} \le 0{,}25 . \tag{3.19}$$

To calculate fluid volume or mass in accordance to average flow parameter value, the pressure transducer includes devices to record measurement results and their integration Pressure values are recorded either on paper (strip or disc diagrams) or electronic media. Determination of the average pressure value in a given period can be computerized.

A separate unit for measuring absolute or excess pressure is installed before the orifice in the pipeline cross-section. Absolute pressure can be measured by both absolute pressure transducers and calculated on the results of barometric (atmosphere) and gauge pressure measurements. Thus, absolute fluid pressure is the sum of the gauge pressure and atmospheric pressure

$$P = P_u + P_a . \tag{3.20}$$

Pressure selection location through differential pressure gauge significantly influences the measured differential pressure value (indicated on pressure distribution curve before and after the orifice) Fig. 3.1, Fig. 3.2 and Fig. 3.3.

Updating of differential pressure gauge readings is significant only in the case of gas outflow measurement in condensation vessel (i.e wet and condensate gases). For example, if the differential pressure gauge is located lower the orifices, then its readings are more than the pressure value, created by the liquid column in the impulse line. Actual pressure value can be written as follows

$$P = P_n - H\rho g, \tag{3.21}$$

where, $\boldsymbol{P_n}$ – manometer reading, Pa;

$\boldsymbol{H}$ – height difference between orifice installation and manometer, m;

$\boldsymbol{\rho}$ – condensate density in the impulse line,kg/m^3;

$\boldsymbol{g}$ – gravitational acceleration, m/c^2.

It should be noted that pressure measurement error significantly affects the outflow measurement fault and gas volume. For example, if pressure measurement error = ±1%, constituent outflow error of pressure equals ± 0,5.

Several differential pressure gauges are installed to expand the measured outflow range and decrease the measurement error in one orifice (Fig. 3.16).

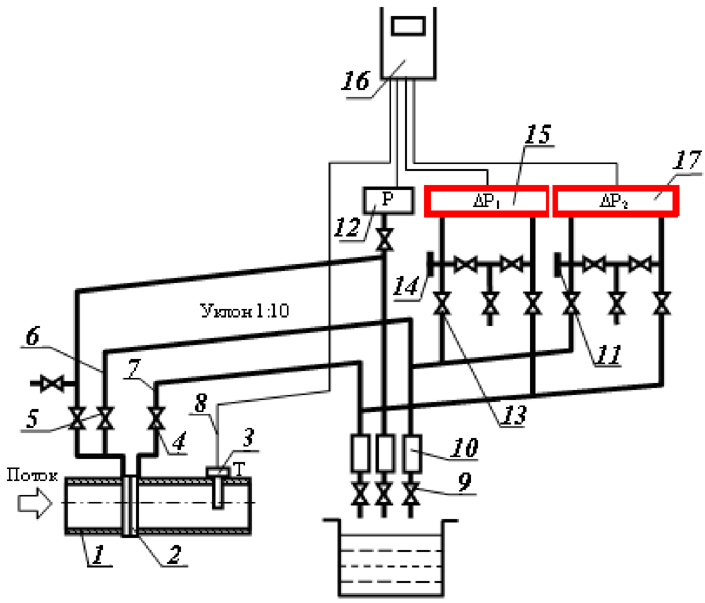


Fig. 3.16. Example of two installed differential pressure gauge:
1- pipeline; 2- diaphragm; 3-temperature transducer; 4, 5 –shutoff valves; 6,7 – connecting lines; 8 –cable to connect temperature transducer with computer; 9 – drain valves; 10 – condensate tank; 11 – plug; 12 – pressure transducer; 13 –valve block; 14 – choker with detachable thread; 15 – primary differential pressure gauge; 16 – computer; 17 – additional differential pressure gauge.

Static pressure selection is as following:

- *separate openings in the pipeline walls or flanges;*
- *several interconnected openings;*
- *ring aperture (uniform or discontinuous) in the averaging chamber.*

According to GOST ***8.586.2-2005*** [20] ***and GOST 8.586.3-2005*** [21], there are three ways for pressure selection- three-radius, flange and angle.

Diaphragms with three-radius and flange methods are depicted in Fig. 3.17 and Fig. 3.18. Axis opening is located at a certain distance from the corresponding diaphragm face, depending on the pressure selection procedure. Thickness is taken into consideration.

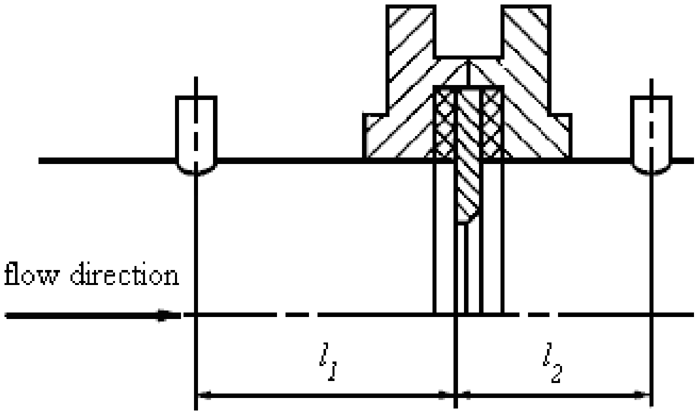


Fig. 3.17. Opening location for three-radius way of pressure selection

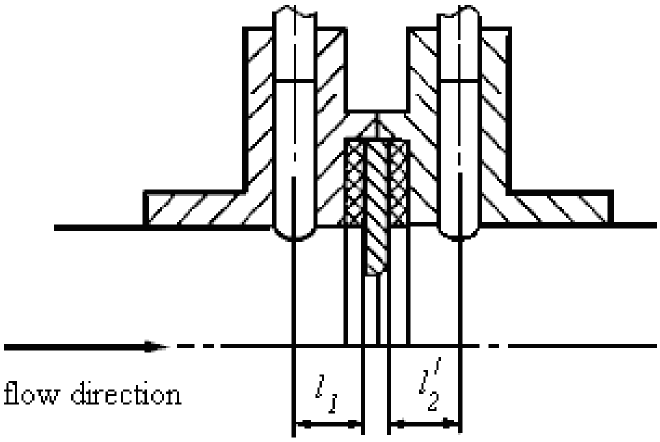


Fig. 3.18. Opening location for flange way of pressure selection

A diaphragm with *three-radius* method *is* depicted in Fig. 3.17. Distance l_1 and l_2 is measured from the diaphragm face. l_1 equals $(1 \pm 0{,}1)D$, while l_2 ranges from:

- $(0{,}5 \pm 0{,}02)D$ at $\beta \le 0{,}6$;
- $(0{,}5 \pm 0{,}01)D$ at $\beta > 0{,}6$.

A diaphragm with *flange* method *is* depicted in Fig. 3.18. l_1 is measured from the inlet diaphragm face , while l_2' – from the outlet diaphragm face. l_1 and l_2' are within the following ranges

- $(25{,}4 \pm 0{,}5)$ *мм* at $\beta > 0{,}6$ and $D < 0{,}15$ *м*;
- $(25{,}4 \pm 1)$ *мм* in the remaining cases.

Осевая линия отверстия должна пересекаться с осевой линией измерительного трубопровода под углом 90° ± 3°.

Orifice axis line intersects the pipeline axis line at an angle of 90°±3°.

Diaphragm with angle method of pressure selection (Fig. 3.19, Fig. 3.20)**.** Orifices are either separate openings or ring apertures. Separate openings can be installed in the pipeline itself or in the flanges. Ring apertures are installed in averaging chambers or in the pipeline flanges (Fig. 3.19).

Pressure selection by venture nozzle (Fig. 3.19) – when applying separate openings or several interconnected openings their axes are located in any axis plane of the pipeline, which in its turn, is uniformly distributed along the perimeter of the pipeline. The orifices should not be installed in the upper or lower sections of the pipeline in order to protect the orifice from contamination, fluid drops or gas bubbles. The orifices are round and cylindrical at a depth corresponding to 2.5 of the orifice diameter (Fig. 3.20).

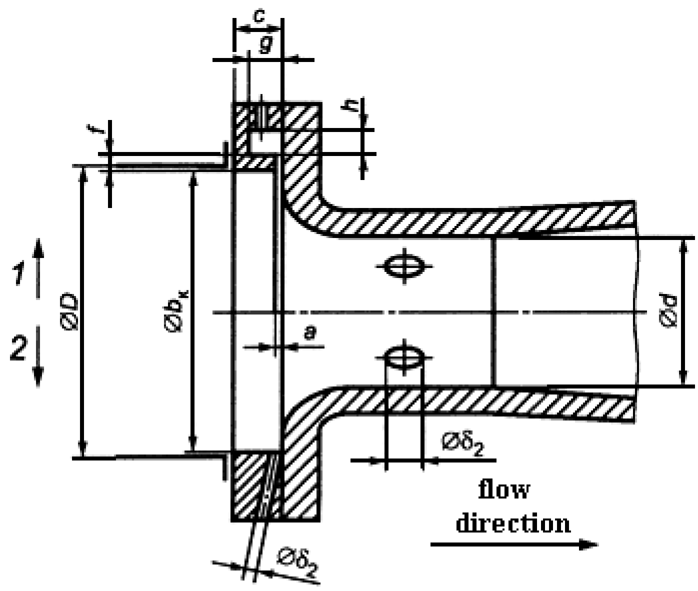


Fig. 3.19. Pressure selection by venture nozzle:
1 –ring aperture; 2 – separate opening

Diameter ***a*** of separate openings or ring apertures correspond to the following conditions:

- ***0,005D ≤ a ≤ 0,03D*** at ***β ≤ 0,65;***
- ***0,01D ≤ a ≤ 0,02D*** at ***β > 0,65***.

If ***D < 0,1*** m, at any value ***β*** , diameter ***a*** there is an increase up to 2mm. Irrespective of value ***β*** diameter ***a*** corresponds to additional conditions:

- ***1 мм ≤ a ≤ 10 мм*** – for pure gas;
- ***4 мм ≤ a ≤ 10 мм*** – for condensed gas, in case of separate orifices (openings) to select pressure.

Ring slots are uniform or dicontinouos along the perimeter of the averaging chamber shell. If there are intermittent slots, then each averaging chamber shell is joined to the internal pipeline wall by 4 or more openings, the axes of which are at equal angles to each other, and where the opening area is not less than 12mm^2.

If separate openings are applied (as in Fig. 3.20), then opening axis lines intersect pipeline axis at 90°, including allowance not more than 3°.

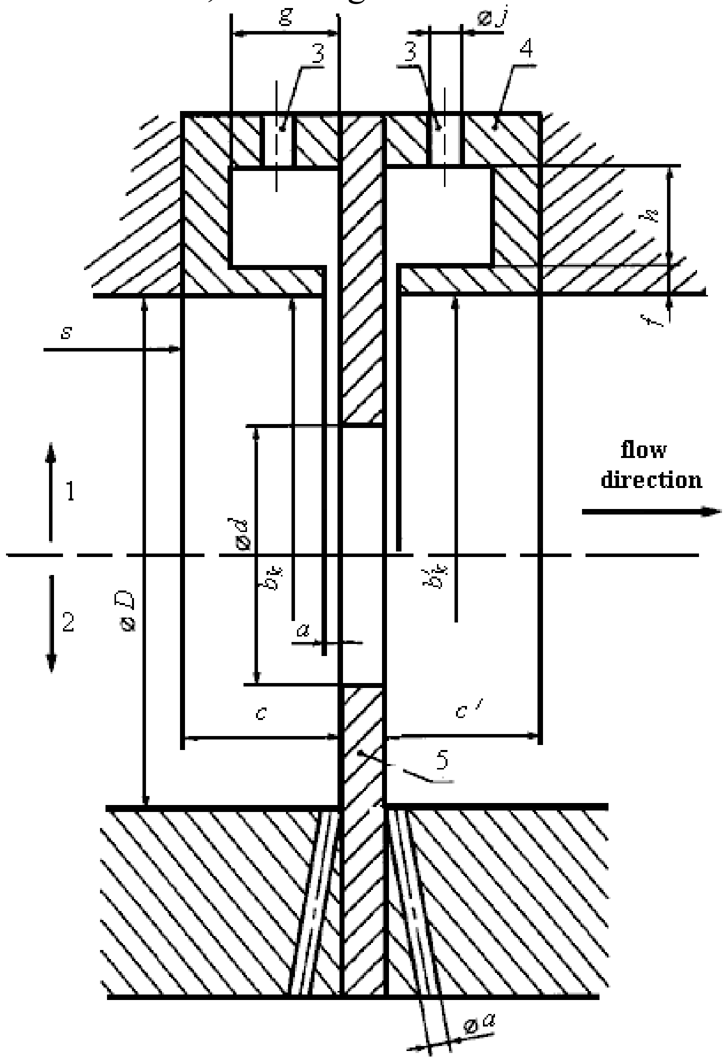


Fig. 3.20. Diaphragm with angle method of pressure selection:
1 – averaging chamber; 2 –separate openings ; 3 – orifice (opening); 4 – averaging chamber shell; 5 –diaphragm; f –slot depth; bk, b/k – internal averaging chamber shell diameter;c, c/ – averaging chamber shell length; a - ring slot width or separate opening diameter; s – distance from shoulder to averaging chamber; g, h, – averaging chamber shell sizes; j – orifice diameter in the chamber to transfer pressure to measurement system

If several separate openings are used in each of the two groups (before and after the orifice), then their axes form equal angles to each other.

When applying several interconnected openings for selecting static pressure before the orifice, after the orifice or orifice throat, they are connected according to the following scheme (Fig. 3.21)

Gas pressure flowrate in the fluid is measured through separate openings in the pipeline or in the averaging pressure chamber before the orifice (if there is one). One and the same opening for static pressure selection is applied to measure differential pressure in the orifice and pressure fluid.

If longitudinal-joined pipes and only one separate opening for selecting static pressure are used, then the seam is on the pipeline of not more than ***0,5D*** and is located directly before the opening for pressure selection, but not in the pipeline cross-section at an angle of ±30° to the above-mentioned opening. If a ring aperture or several interconnected openings are used for pressure selection, then the joint is in located in any section of the pipeline.

In pipelines with spiral welded seams, the internal smooth pipeline surface is up to ***10D*** before the orifice (or along the surface between orifice and nearby local resistance – only if this section is not more than ***10D***) and not more than ***4D*** after the orifice (after venture tube- not less than ***4d***) through its mechanical treatment.

The following requirements are considered when selecting the pressure selection method in the diaphragms (Table 3.7).

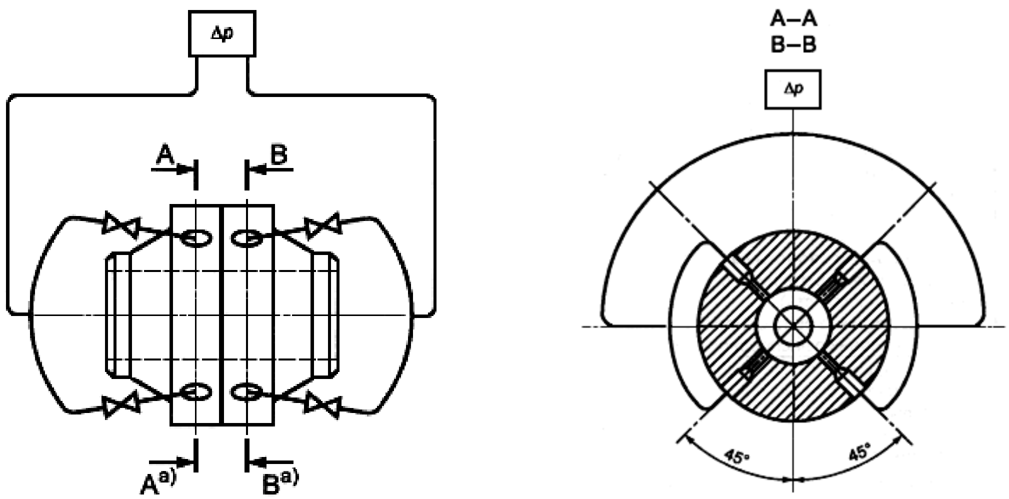


Fig. 3.21. Several interconnected openings for selecting static pressure: cross-section A-A (before orifice) and cross-section B-B (after orifice)

Table 3.7

Advantages and disadvantages of sample gas pressure selection

Selection method	Advantages	Disadvantages
Angle	- convenient diaphragm installation; - application of ring averaging chamber to average pressure, which in its turn, decreases the centering error in the diaphragm installation; - decreases MC impact on flowmeter readings.	- measured differential pressure depends on opening diameter or slot diameter in selecting pressure - high contamination probability of opening.
Flange and Three-radius	- less contamination of orifice; - insignificant decrease of pipeline wall roughness impact on diaphragm efflux coefficient (according to readings)	- static pressure before and after the diaphragm is measured (averaged) along the pipeline perimeter without applying additional special devices; - pipeline walls are drilled in the three-radius method.

3.1.8. Scheme of differential pressure measurement transducer or differential pressure gauge

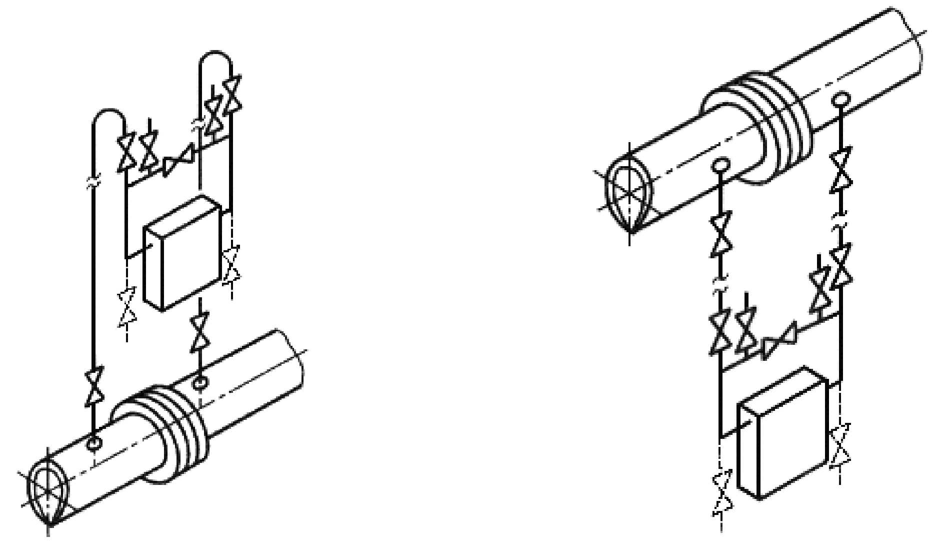
Differential pressure measurement transducer or differential pressure gauge (DPMT) is joined to the pipeline in the following ways:

- *above the pipeline;*
- *under the pipeline;*
- *above the opening for pressure selection (vertical pipeline);*
- *below the opening for pressure selection (vertical pipeline).*

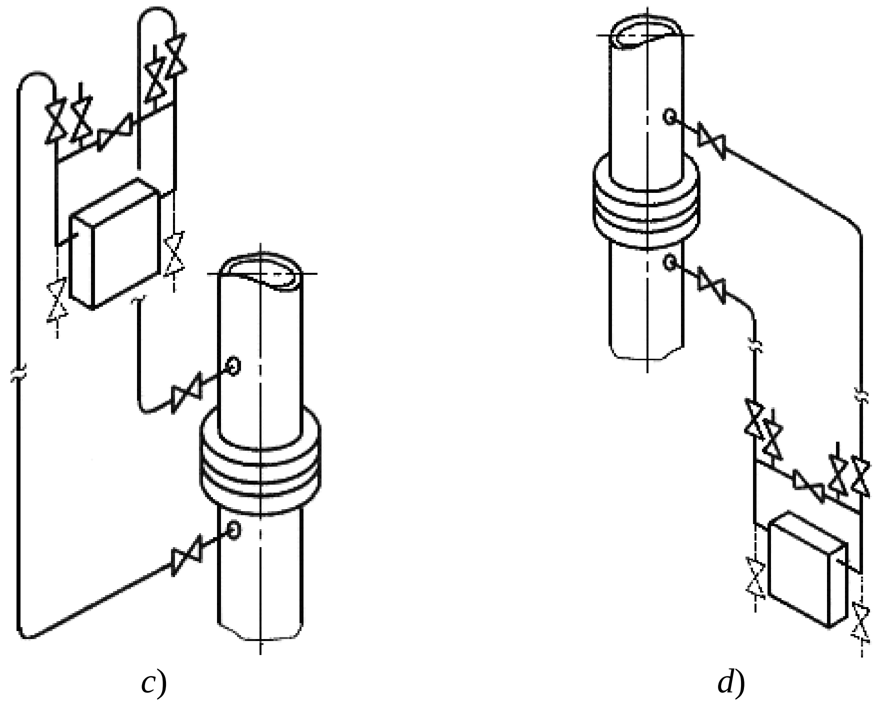
The differential pressure transducer is directly joined to the pipeline through the shutoff valves if pure dry gas is transported (Fig. 3.22).

The DPMT is joined to the pipeline through ***condensate (separation) vessels, pits or treating systems*** to remove suspension or wet from gas in order to exclude measurement errors, if ***condensate gas*** (Fig. 3.23) or ***pure moisture gas*** (Fig. 3.24) is transported.

Pit chambers are located in the lower part of the joining pipes (joints). The pit chamber connection scheme is depicted in Fig. 3.25. Typical pit chamber is shown in Fig. 3.26. There is free space at the top of the tank to the blowout valve. The ball- valve is easy to clean and wash-out in case of contamination. The pit chamber have different sizes according to technical requirements, cleaning-out, amount of solids in the flow and/or condensation level.

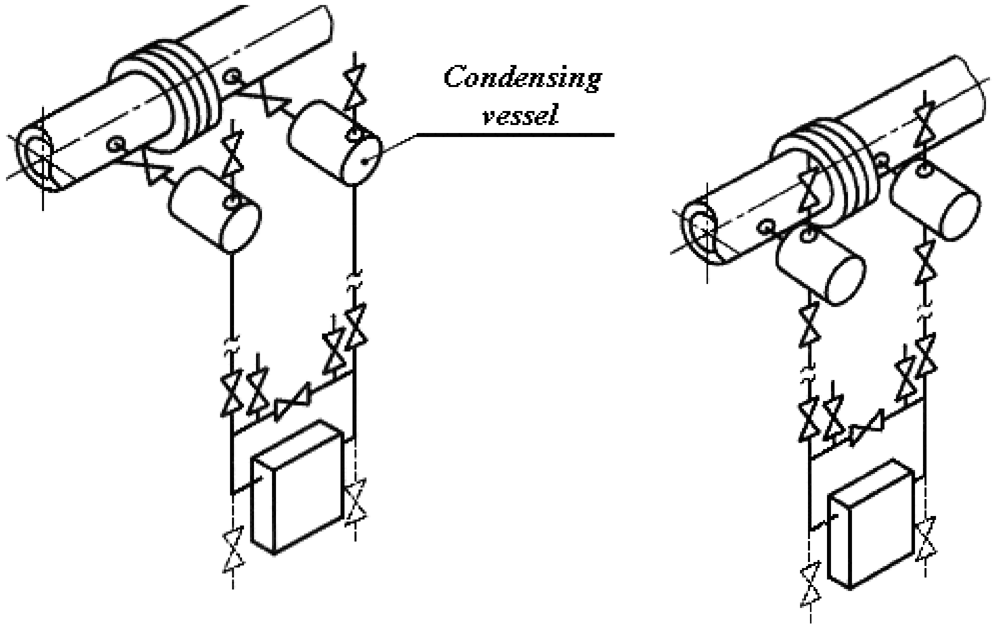


a) *b*)



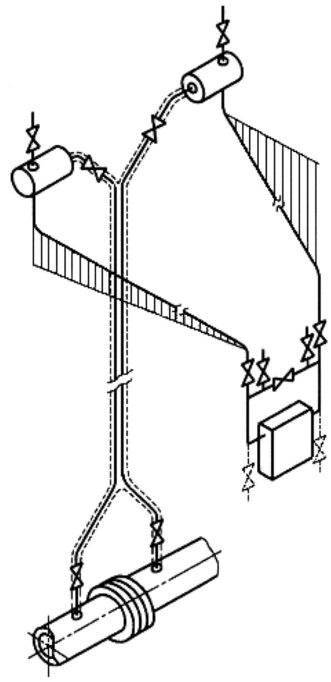
c) *d*)

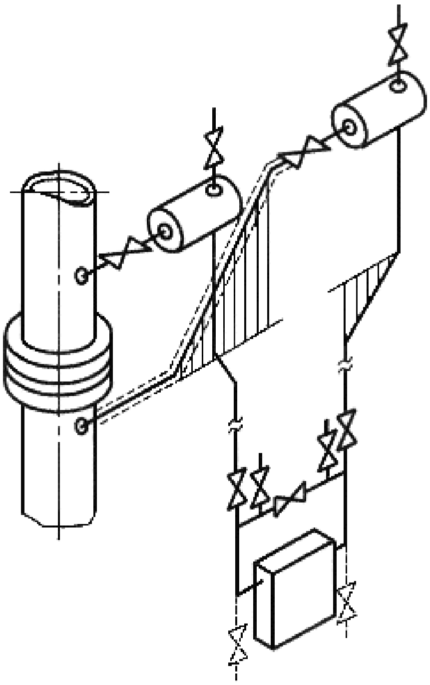
Fig. 3.22. Location of differential pressure measurement transducer or differential pressure gauge for transporting pure natural gas:
a) above pipeline; b) below pipeline; c) above the opening for pressure selection (vertical pipeline); d) below the opening for pressure selection (vertical pipeline).



a)

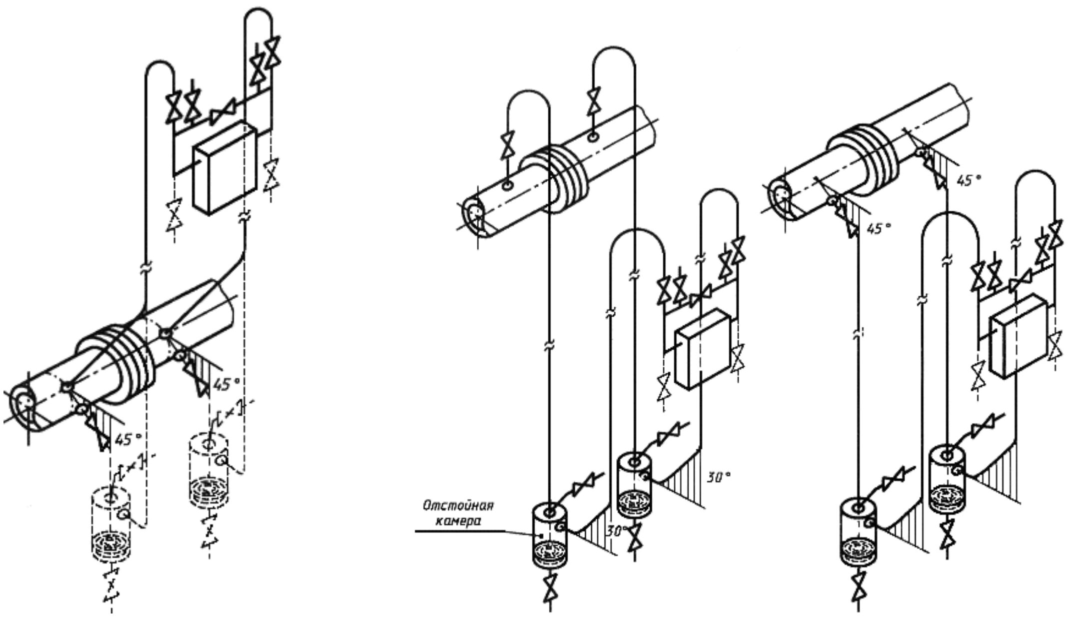
Inclination of two connected pipes is identical





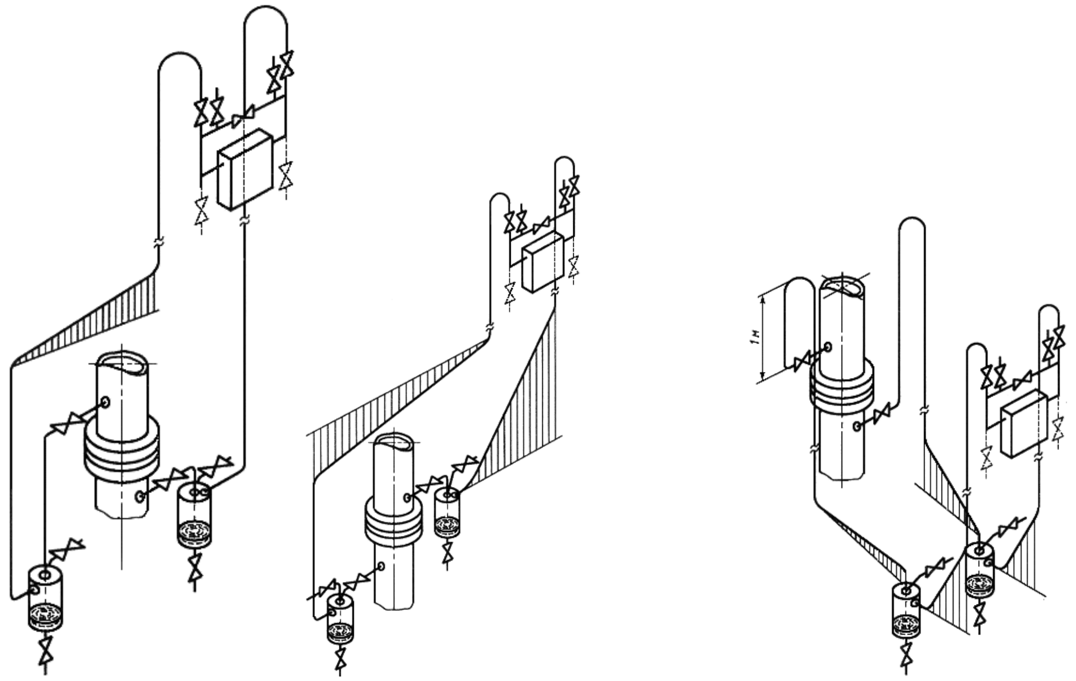
b) *c*)

Fig. 3.23. Location of differential pressure measurement transducer or differential pressure gauge for transporting condensate gas:
a) above pipeline; b) below pipeline; c) below the opening for pressure selection (vertical pipeline)



a) *b*)

Inclination of two connected pipes is identical



c) *d*)

Fig. 3.24. Location of differential pressure measurement transducer or differential pressure gauge for transporting pure wet gas:
a) above pipeline; b) below pipeline; c) above the opening for pressure selection (vertical pipeline); d) below the opening for pressure selection (vertical pipeline)

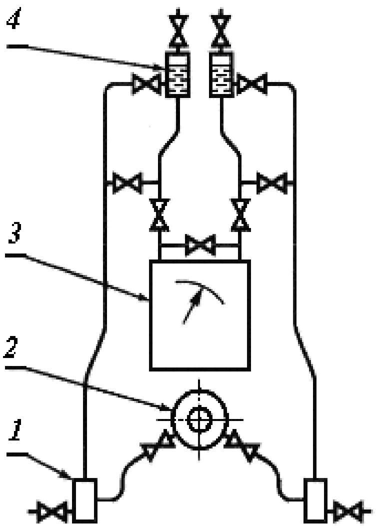


Fig. 3.25. Pit chamber connection to measure water flow rate in DPT unit when installed above the orifice:
1 – pit chamber; 2 – orifice; 3 – differential pressure transducer or differential pressure gauge; 4 – air reservoir

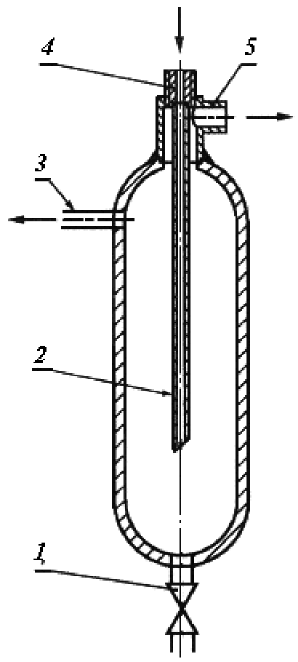


Fig. 3.26. Pit chamber:
1 – blowout valve; 2 – acicular tube; 3 –outlet nozzle;
4 – inlet nozzle; 5 – ventilation valve

Separation vessel is applied in the case of corrosion, condensability and freezing in the joining pipes, high viscosity and sludge formation. Separation vessels are filled up with a liquid, separating the fluid from the DPT or from the balance liquid, which is applied in the differential pressure transducer or differential pressure gauge.

Separation vessels are used with and without baffle plate. In separation vessels without baffle plates, the separating liquid should not mix or react with the measured fluid or balance liquid and its density is significantly different from the density of these two substances to provide steady surface contact.

To measure gas flow rate, the separation vessels are located above the orifice, while DPT is located above or below the orifice. If the DPT is located below the orifices in measuring gas flow rate, the joining pipes are connected to the lateral separation vessel fitting.

Separation vessel capacity is more than the fluid volume at maximum loading in the DPT. The diameter throughout the separation vessel length is equal. Separation vessel design is depicted in Fig. 3.27.

Separation vessels with baffle plates are applied in the case if the corresponding separating liquid with required chemical and physical properties can not be selected. These baffle plates are flexible diaphragms and rolling diaphragms. The baffle plate parameter-«loading -relocation»is identical for two separating vessels.

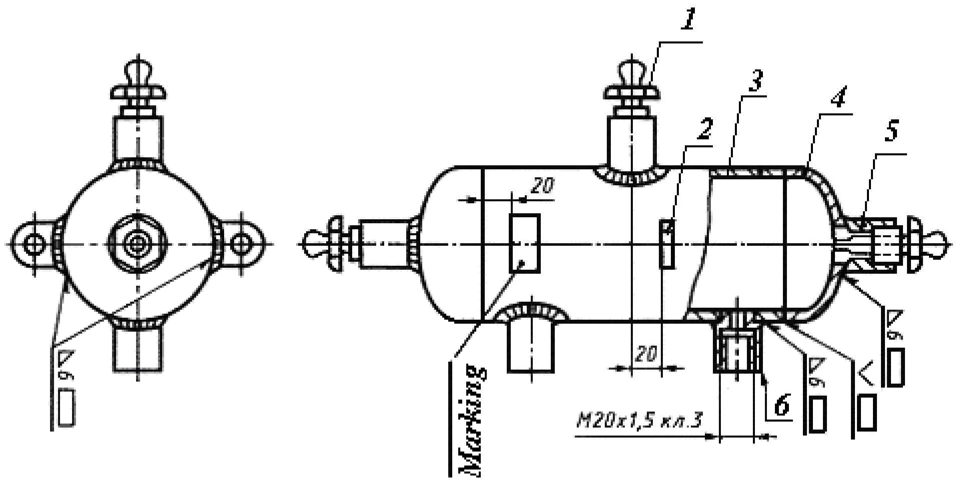


Fig. 3.27. Separation vessel design: 1 - plug; 2 - eye; 3 - shell; 4 - bottom; 5- nozzle; 6 – nozzle

Examples of separating liquids are depicted in Table 3.8.

Table 3.8

Separating liquid properties

Liquid	Density at 20 °C, kg/m^3	Temperature, °C	
		freezing	boiling
Dibutyl phthalate	1047	–35	340
Glycerin	1262	–17	200
Glycerin and water mixture (volume ratio - 1:1)	1130	–22,5	106
Ethanol	789	–112	78
Ethylene glycol	1113	–12	197
Water and ethylene glycol mixture (volume ratio - 1:1)	1070	–36	110

Treatment system (Fig. 3.28) is to prevent contaminated or aggressive substances occurring in joining pipes and DPT. Treatment systems substitute not only the separation vessels, but also the pit chambers.

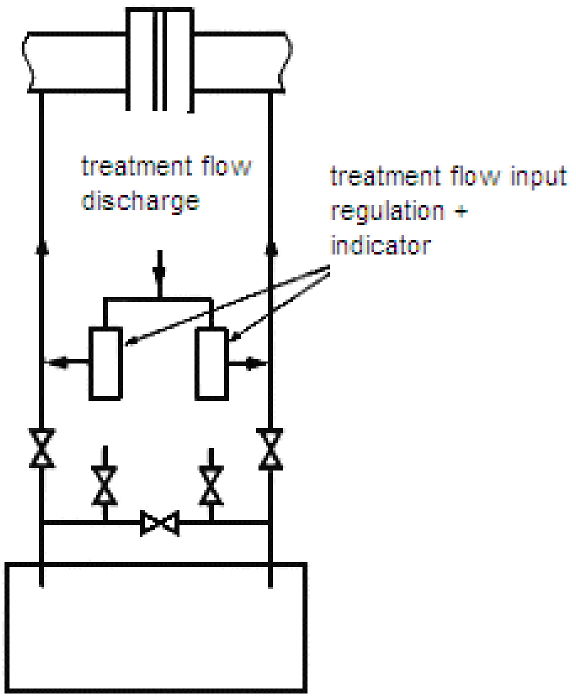


Fig. 3.28. Treatment system unit

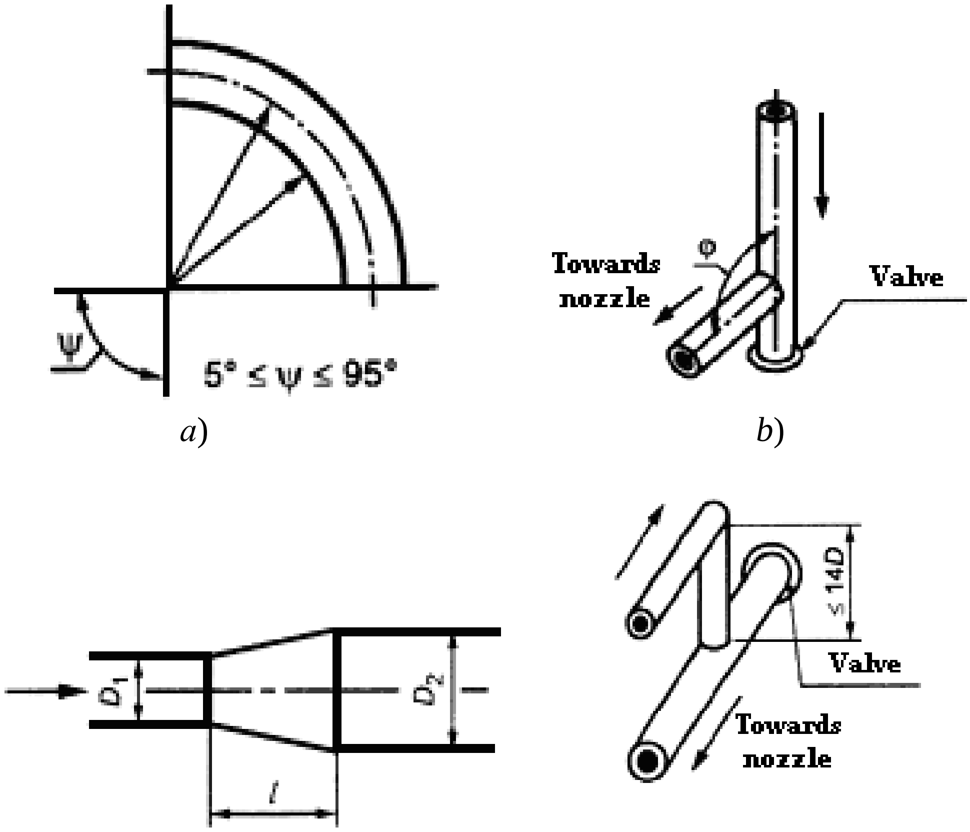
The cross-section throughout the joining tube length is constant when applying the treatment system. Joining tubes are connected to the minus and plus averaging chamber and have the same length and number of couplings.

To provide equal treatment flow output in both joining tubes, flowmeters are installed in the treatment system (for example, rotameter) between blowout valves and treatment flow input point in the joining tube.

3.1.9. Local resistance unit impact on gas flow rate measurement and methods to decrease it

Gas pipeline system includes not only linear sections, but also turnings, diameter alterations and installed local resistance units (valves, elbows, legs and others) (Fig. 3.29).

Local resistance units distort flow structure and result in additional flow rate measurement error. Thus, there are straight pipeline sections before and after the flowmeter. Approximate length of straight pipeline sections for several flowmeter types (Table 3.9).



a) *b*) *c*) *d*)

Fig. 3.29. Examples of local resistance units:
a) elbow; b) tee; c) transition area; d) local resistance offset

Table 3.9

Approximate length of straight pipeline sections

Flowmeter types	Dy, mm	Length of straight sections in Dy		Pressure P_{max}, kgc/cm^2	Gas flow rate Q_{max}, m^3/hr
		Before	After		
Turbulent	50…600	5	3	Up to 100	25-25000
Tapering units and pressure tubes	12,0…1400	20…50	4…8	No limits	from 10
Vortex	15…300	5…20	2…10	Up to 16	50-20300
Ultrasonic (acoustic)	25…800	5…10	3…7	Up to 300	from 10

Table 3.10

Length of straight sections between diaphragm and several types of local resistance

Installation location of local resistance units	Local resistance unit type	Relative length in straight pipeline section L at β			
		≤ 0,2	0,4	0,5	0,6
After diaphragm	Any local resistance (except symmetrical sharp tapering)	4	6	6	7
Before diaphragm	90° elbow	6	16	22	42
	Muff- tee, changing the flow direction or conical 90° elbow	3	9	19	29
	Muff-tee, not changing the flow direction	10	11	14	18
	Convergent tube	5	5	8	9
	Diffuser	6	12	20	26
	Tee for mixed flows	34	37	41	49
	Tee for branching flow	14	17	20	26
	Roll- tap valve or valve	12	12	12	14
	Shut-off valve	18	19	22	26
	Symmetrical sharp expansion	51	58	64	70
	Symmetrical sharp narrowing or large capacity	30	30	30	30

The minimum length of straight pipeline areas before and after the flowmeter depends on the relative diaphgram opening diameter and local resistance unit type. The length of straight pipeline areas are calculated according to GOST ***8.586.1.2005*** and is determined by ***β*** *(relative orifice diameter, determined as the orifice diameter d to the internal pipeline diameter before the tapering unit D) (Table 3.10).*

If the diaphragm efflux coefficient errors U'_{C_0} for three methods of pressure selection are:

$$U'_{C_0} = 0{,}7 - \beta \text{ at } 0{,}1 \le \beta < 0{,}2,$$

$$U'_{C_0} = 0{,}5 \text{ at } 0{,}2 \le \beta \le 0{,}6,$$

The length of straight pipeline sections can be reduced for additional error allowance to ***efflux coefficient C*** (the ratio of actual fluid output to its theoretical value). If the value error is more than the allowance, then orifice box or unit for flow preparation is installed in the pipeline.

3.1.10. Orifice boxes

Orifice boxes eliminate torsion and gas flow asymmetry, created by local resistance units in the pipeline (for example, elbows in different planes). Orifice boxes installation reduces the length of straight pipeline sections before the orifices. [19-23, 25].

Orifice box: *a device used to convert alternating current into direct current.*

Orifice box is applied with the following flow rate transducer types:

- *variable differential pressure method, created by orifices;*
- *turbulence flow rate transducers;*
- *ultrasonic flow rate transducers.*

Orifice box – a unit that eliminates or significantly reduces turbulence, but does not provide elimination of asymmetrical or symmetrical flow velocity deformation distribution. Tubular orifice box "AMCA" and "Etoile" are such examples. Tubular orifice box design is depicted in Fig. 3.30.

The tube length ***L*** ranges from ***2D*** to ***3D***, preferably closer to ***2D***. Jet – rectifier includes connective parallel contacting tubes, installed in the pipeline. The number of tubes is not less than 19 and length not less than $\boldsymbol{10d_{mp}}$,, which is the external tube diameter. The tubes are joined together as a “bundle” and installed in the pipeline. The tube axis is parallel to the pipeline axis.

Hydraulic resistance coefficient of tubular orifice box depends on the number of tubes and their wall thickness. A 19-tubed tubular orifice box where wall thickness is less than ***0,025D,*** hydraulic resistance coefficient equals 0.75.

Alternative tubular orifice box design is connected to the collar through the external ring.

"AMCA" orifice box includes a «honeycomb» design of square cells the sizes of which are depicted in Fig. 3.31. The edges are not only thin, but also durable.

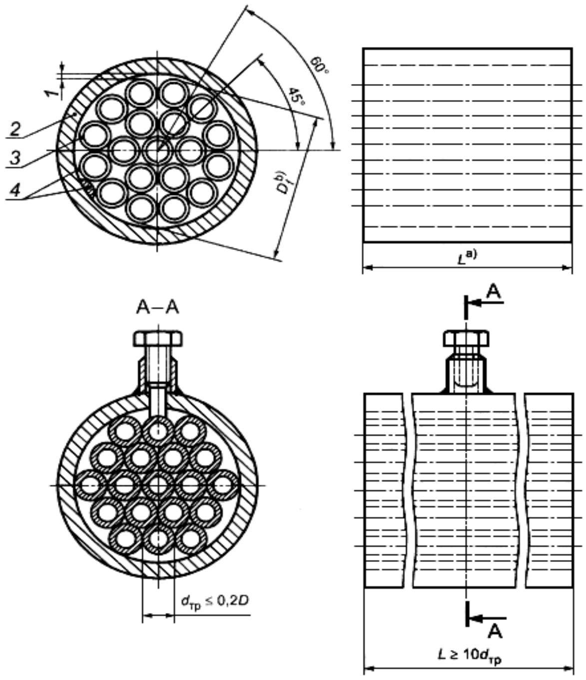


Fig. 3.30. Tubular orifice box:
1 –minimized gap; 2 – pipeline wall; 3 – tube wall thickness (less than 0,025 D); 4 – additional centering spacer (usually in 4 locations)

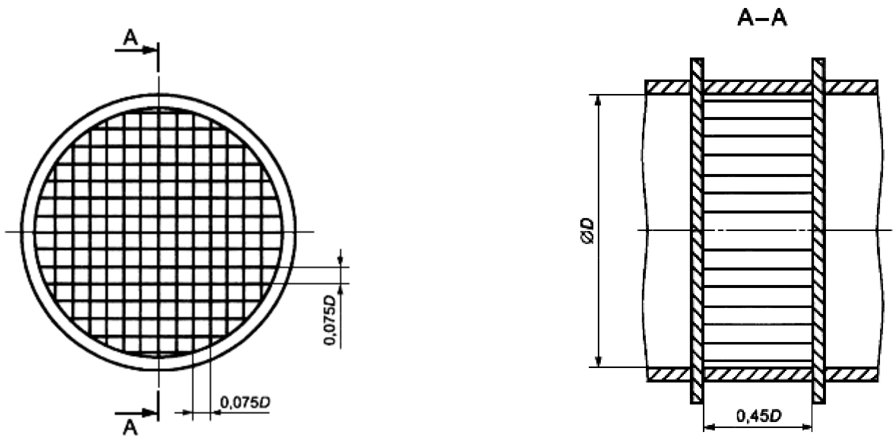


Fig. 3.31. "AMCA" Orifice box

The hydraulic resistance coefficient in "AMCA" orifice box equals 0,25.

"Etoile" Orifice box design (Fig 3.32) includes 8 radial blades located at same angles. The blade length is twice the pipeline diameter and as thin as durability allows. The hydraulic resistance coefficient in"Etoile" jet – rectifier equals 0,25.

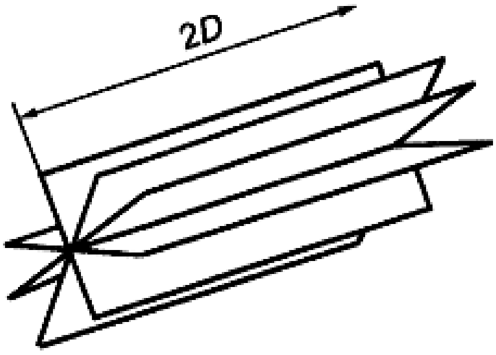


Fig. 3.32. Orifice box "Etoile"

SV –type orifice box *includes the following units*:

- *orifice box consisting of a disc with openings and block of guiding blades;*
- *outlet and inlet fittings with collars*
- *intermediate fittings with collars («drum»);*
- *distance telering providing possible orifice box installation on the pipeline.*

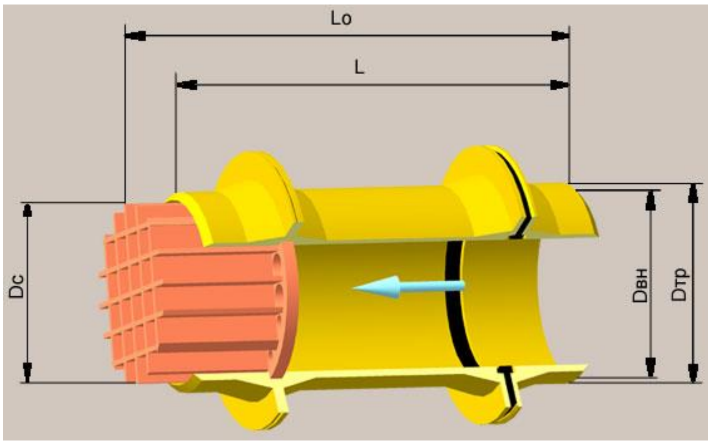


Fig. 3.33. SV –type Orifice box

Table 3.11

SV –type orifice box characteristics

Type	Size, mm					
	$D_{тр}$	$D_{ф}$	$D_{вн}$	$D_{с}$	L	L_{o}
SV 6,3-300	325	460	300	298	900	953
SV 6,3-400	426	580	400	398	1142	1227
SV 6,3-500	530	700	508	506	1290	1454
Operation gas pressure – not more than 6,3 MPascals.						
Operating gas temperature range-30 °C ÷ +50 °C						

The above-mentioned device provides the contamination control during differential pressure and its treatment. All design findings (SV –type orifice box) are Ukrainian and Russian patents: model № 3347 (26.01.04) and № 41357.

Daniel orifice box

Daniel Profiler orifice box when installed in the pipeline creates a complete flow profile, in spite of all the local resistance impact (Fig. 3.34).

Such a device reduces the pipeline length up to 17 d.The model-device only includes collar installation. Testings proved that Daniel Profiler orifice box requirements correspond to Standards AGA 14.3.

Fig. 3.34. Daniel orifice box

3.1.11. Flow Conditioners

***Flow conditioner (FC)** –technical device to eliminate flow turbulenc and decrease flow velocity strain diagram.*

Examples are "Gallagher", "K-Lab NOVA", "NEL (Spearman)", "Sprenkle" and "Zanker".

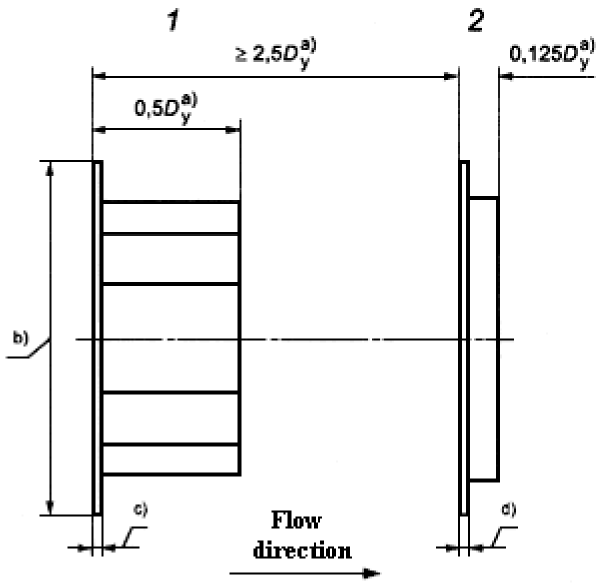


Fig. 3.35. FC "Gallagher": 1 - anti-vortex unit; 2 – profile unit

FC"Gallagher» includes anti-vortex unit, pit and profile units (Fig.3.35), where *a) –reference pipeline diameter; b) –length equal to external FC collar diameter; c) 3,2 mm at Dy from 50 to 75 mm, 6,4 mm at Dy from 100 to 450 mm, 12,7 mm at Dy from 500 to 600 mm, 12,7 mm at Dy from 50 to 300 mm, 17,1 mm at Dy from 350 to 600 mm; d) 3,2 mm at Dy from 50 to 75 mm, 6,4 mm at Dy from 100 to 450 mm, 12,7 mm at Dy from 500 to 600 mm.*

The profile device (Fig. 3.36) includes:

- *3 openings, located along the diameter from 0,15D to 0,15D. Opening diameter is the total opening area from 3% to 5% of the pipeline cross-section;*
- *8 openings located along the diameter from 0,44D to 0,48D. Opening diameter is the total opening area from 19% to 21% of the pipeline cross-section;*
- *16 openings, located along the diameter from om 0,81D to 0,85D. Opening diameter is the total opening area from 25% to 29% of the pipeline cross-section*

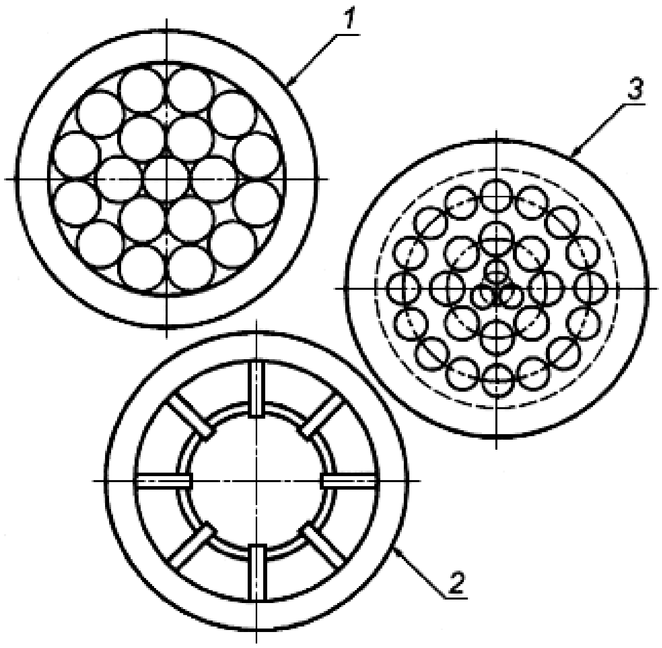


Fig. 3.36. Typical components of FC "Gallagher" (front view):
1 – anti-vortex unit –tubular type variant: uniform concentric "bunch" of 19 tubes (installed on hinges); 2 – anti-vortex unit – blade type variant: 8 blades, the length from 0,125D to 0,25D, concentric to the pipe (unit installed at the pipeline entrance); 3 –profile unit.

Hydraulic resistance coefficient of ***FC*** "Gallagher" depends on technical requirements and equals 2.

FC "K-Lab NOVA" includes a disc with 25 drilled openings, located as symmetrical circle (Fig. 3.37). Perforated disc thickness ranges from 0,125D to 0,15D.

Thickness, external diameter and collar face surface depend on the type and its application. Opening sizes are the internal pipeline diameter and Reynolds number. If $Re \geq 8 \cdot 10^5$:

- *central opening diameter(0,18629±0,00077)D,*
- *8 opening diameter (0,163±0,00077)D, the center of which is located on the diameter radius 0,5D±0,5 мм;*
- *16 opening diameter (0,1203±0,00077)D, the center of which is located on the diameter radius 0,85D±0,5 мм.*

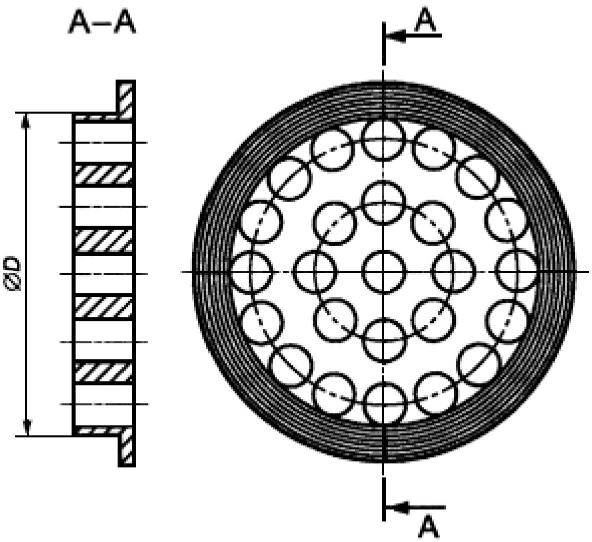


Fig. 3.37. FC "K-Lab NOVA"

If $8 \cdot 10^5 > Re \geq 10^5$:

- *central opening diameter(0,22664±0,00077)D;*
- *8 opening diameter (0,16309±0,00077)D, the center of which is located on the diameter radius 0,5D±0,5мм;*
- *16 opening diameter (0,12422±0,00077)D, , the center of which is located on the diameter radius 0,85D±0,5 мм.*

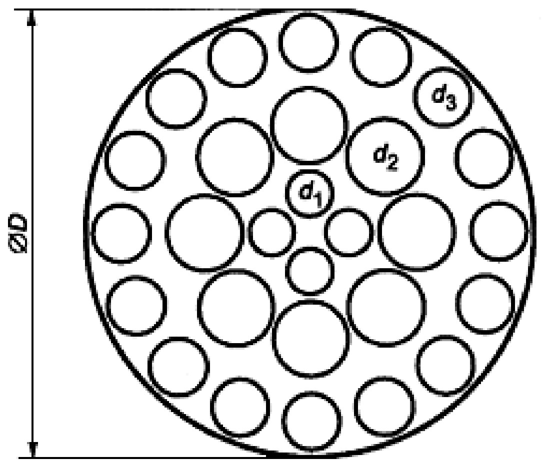


Fig. 3.38. FC "NEL (Spearman)"

Hydraulic resistance coefficient of FC "K-Lab NOVA" equals 2.

FC "NEL (Spearman)" (Fig. 3.38). Opening sizes are the internal pipeline diameter. Opening requirements are the following:

- *4 openings (d_1) diameter 0,10D, the center of which is located on the diameter radius 0,18D;*
- *8 openings (d_2) diameter 0,16D, the center of which is located on the diameter radius 0,48D;*
- *16 openings (d_3) diameter 0,12D, the center of which is located on the diameter radius 0,86.*

Perforated plate thickness equals 0,12*D*. Hydraulic resistance coefficient of FC "NEL (Spearman)" equals 3.2.

FC"Sprenkle" **(**Fig. 3.39) includes 3 perforated plates, located sequentially at a distance of$(1\pm0,1)\,D$ from each other.

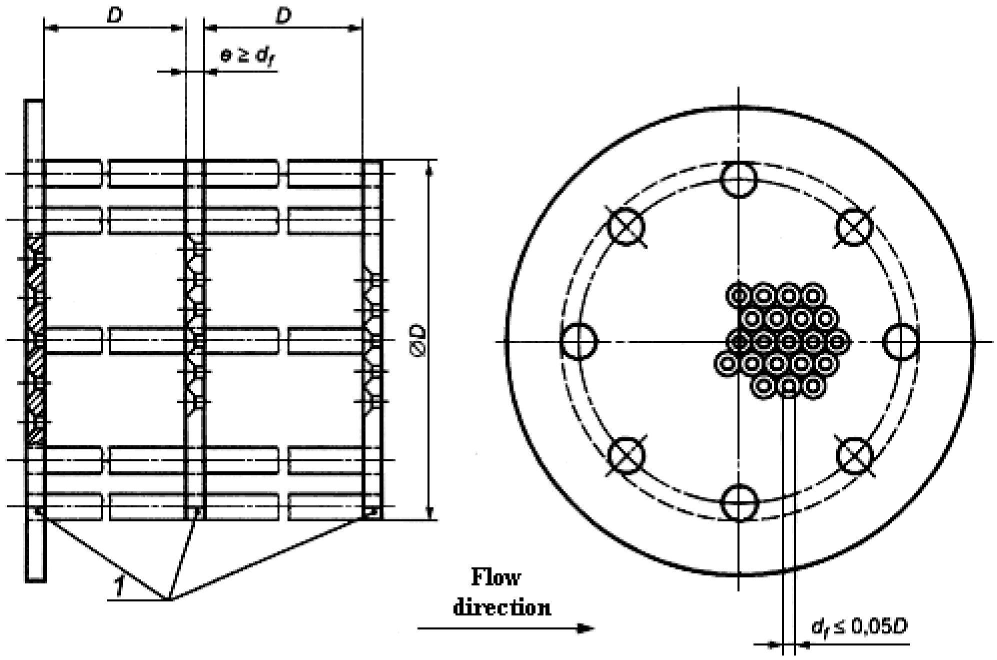


Fig. 3.38. FC "NEL (Spearman)"

To decrease pressure loss the openings have 45° - facets at the flow inlet (entrance), while the total area is 40% of the pipeline cross-section. The plate thickness to opening diameter ratio is not less than 1, while the opening diameter - not more than 0,05*D*.

Plates are joined together by springs or pins, located along the periphery of the pipeline gap and its diameter is not only as small as possible, but also have enough durability for fastening. Hydraulic resistance coefficient of FC"Sprenkle" equals 11, if the inlet opening edges have facets, if none- 14.

FC "Zanker" *(Fig. 3.40).*

FC "Zanker" includes perforated plates with openings behind which are channels (one in every opening), formed in the cross-section of near-by plates. Plates are not only as small in thickness as possible, but also have enough durability. Hydraulic resistance coefficient of FC "Zanker» equals 5.

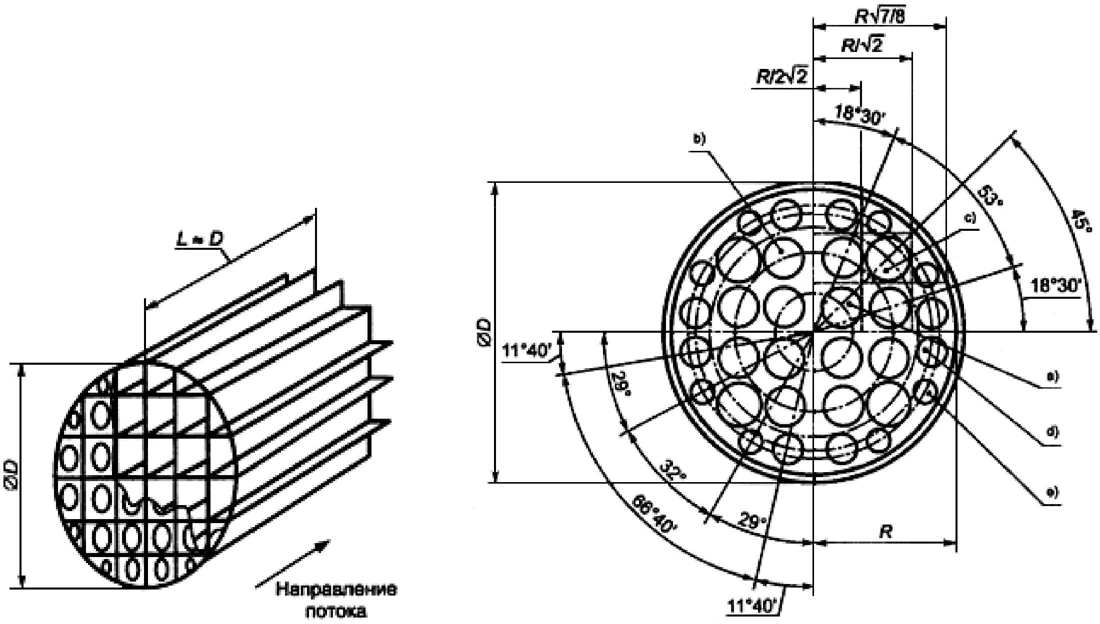


Fig. 3.40. FC "Zanker":
a) 4 openings (d1) diameter 0,141D, the center of which is located on the diameter radius 0,25D; b) 8 openings (d1) diameter 0,139D, the center of which is located on the diameter radius 0,56D; c) 4 openings (d1) diameter 0,1365D, the center of which is located on the diameter radius 0,75D; d) 8 openings (d1) diameter 0,11D, the center of which is located on the diameter radius 0,85D; e) 8 openings (d1) diameter 0,077D, the center of which is located on the diameter radius 0,90D.

3.2. Flow rate and hydrocarbon volume measurement through flow meters

Nowadays, there are a great number of devices based on the physical parameters in order to measure different fluid and gas flow rates. It should be noted that there is no ideal method to measure flow rate. However, the existing methods have their own advantages and disadvantages. Thus, the most important facts in pipeline design and construction is to select the optimal measurement method which includes the following requirements: specific features of the flow rate measurement method, operation conditions, engineering and metrology reliability, cost operation expenses, computerization, information storage and additional services

3.2.1. Gas diaphragm meter

Gas diaphragm meter (diaphragm, chamber) is based on the following procedure- different mobile transforming units separate gas into volume fractions, then cycling summation.

Gas diaphragm meter (Fig. 3.41) includes shell, top, measurement unit, oscillating – lever mechanism to connect mobile diaphragm parts with upper valves, gas- selector valve, saddle valve (lower part of the selector valve) and meter unit. The shell and meter top are:

- *Steel fabricated with anti-corrosion coating and anti-spark formation;*
- *Aluminum, cast.*

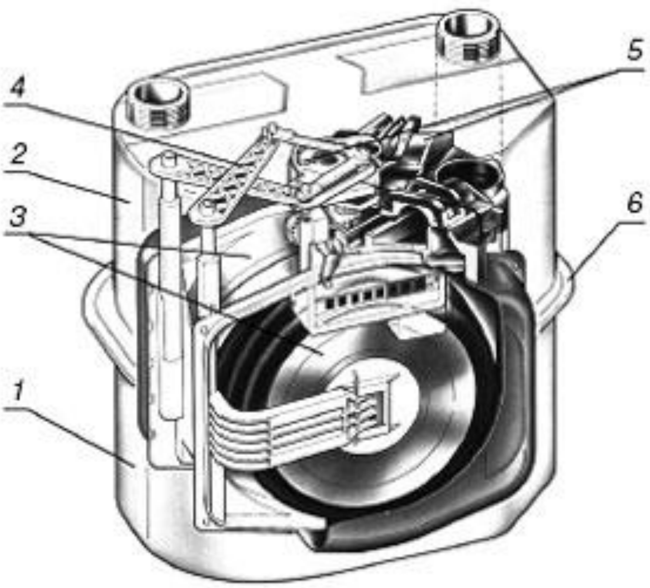


Fig. 3.41. Diaphragm meter:
1 – shell; 2 – top; 3 – measurement unit; 4 – oscillating – lever mechanism; 5 – upper valves, gas- selector valve; 6 – coupling band

Steel fabricated shell and top are joined by sealant material providing tightening. Aluminum shell and top are sealed by special spacers and screws, where one screw is a seal.

Elements and components for the diaphragm meter measurement unit are plastics. The advantages of plastic measurement units are the following:

low cost;

high resistance to gas chemical components;

friction coefficient decrease in the mobile meter parts.

The measurement unit includes two to four chambers in accordance to measured gas volume and composition (Fig. 3.42)

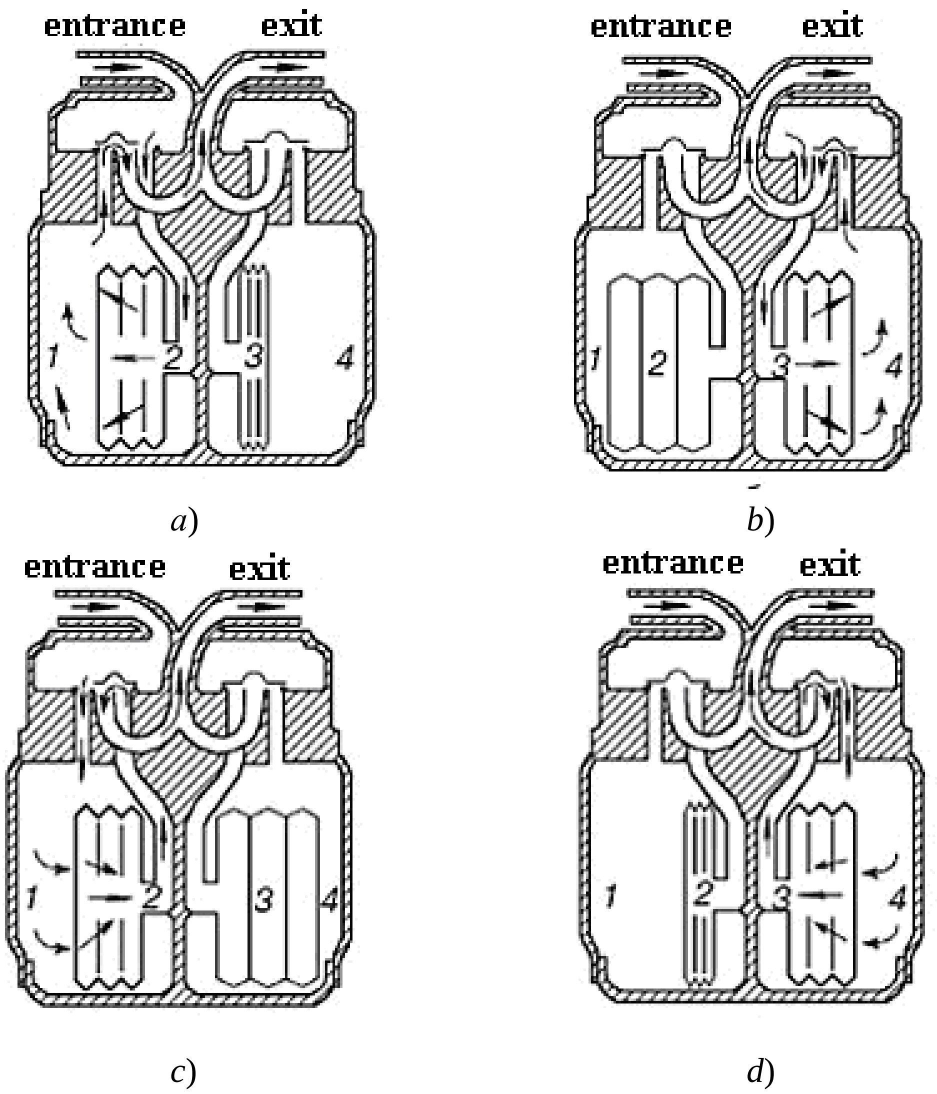


Fig. 3.42. Diaphragm meter performance

Gas meter performance:

a) Measured gas flow enters the upper shell chamber through the entrance nozzle and then through the open valve into chamber ***(2).*** Gas volume increase in chamber (***2)*** results in the diaphragm relocation and gas displacement from chamber ***(1)*** to the exit through saddle valve slots and then to the exit meter nozzle. When the diaphragm lever is near the chamber wall (***1)***, the diaphragm stops as a result of the valves cut-over. The valve in mobile chambers (***1)*** and (***2)*** completely blank the saddle valves in these chambers, shutting off this chamber block.

b) Chamber valve (***3)*** and (***4)*** open the entrance for gas from the upper shell chamber meter into chamber (**3),** fills it up, which results in the diaphragm relocation and gas displacement from chamber (***4)*** to the exit nozzle through slots in the saddle valve. When the diaphragm lever is near the chamber wall (***4)***, the diaphragm stops as a result of the valves cut-over in chamber (***3)*** and (***4)***.

c) Chamber valve (***1), (2)*** opens the upper shell meter chamber for the gas to enter chamber ***(1)***. When the gas is in chamber 1, diaphragms (***1), (2)*** moves, displacing the gas from chamber (***2)*** into the exit nozzle through saddle valve slots. When the diaphragm lever is near the chamber wall (***2)***, the diaphragm stops as a result of the valves cut-over in chamber (***1)*** and (***2)***.

d) Chamber valve **(3),** (**4)** opens the upper shell meter chamber for the gas to enter chamber (***4)***. When gas is in chamber (***4)***, diaphragms (***3), (4)*** move, displacing the gas from chamber (***3)*** into the exit nozzle through saddle valve slots. When the diaphragm lever is near the chamber wall (***3)***, the diaphragm stops as a result of the valves cut-over in chamber (***3)*** and (***4)***.

Table 3.12

Performance cycles of diaphragm meters

Meter chamber location	Chamber 1	Chamber 2	Chamber 3	Chamber 4
a	Drain out	Filling up	Empty	Filled up
b	Empty	Filled up	Filling up	Drain out
c	Filling up	Drain out	Filled up	Empty
d	Filled up	Empty	Drain out	Filling up

Disadvantages:

- Down state under conditions of contaminated gas;
- possible breakdowns during abrupt pneumatic-mechanical impact;
- gas pipeline shut-down due to breakdowns (for example, rotor jam-up of rotor gas meter);
- relatively large size and cost in comparison to other types.

Advantages:

- Only measurement method that provides direct (not indirect) measurement of gas volume;
- non-sensitive to any flow velocity distribution distortion at the entrance and exit (no straight sections can be used and decreases the gas meter unit size); wide measurement range (up to 1:100 or more).

Thus, the above-mentioned gas meters are applied in cycling gas usage, for example, boiler with impulse combustion regime.

3.2.2. Rotameters (volumetric)

Rotameters (volumetric) are the simplest and widely used in the petroleum industry. A rotameter comprises a vertically disposed tapered flow passage with cross section progressively increasing from the bottom inlet to the top outlet and a flow obstructing member suspended in the fluid stream by the drag force exerted by the upwardly moving fluid. The transporting fluid flow is divided into fractions mechanically. This division is the result of eccentric reinforced rotary blades or rotor gears. During motion, at specific time intervals, measurement chambers are formed, the size of which is very precise. The fraction amount in a time unit flowing through the chamber determines the rotation frequency [30].

Mass flow meter is a device that measures how much fluid is flowing through the tube. It does not measure the volume of the fluid passing through the tube but it measures the amount of mass flowing through the device. The measuring unit in the oil volume meters with oval gear wheels includes two high-accuracy gears (Fig. 3.43). The performance of the above-mentioned meter is as following: two oval gears, rotating under the impact of the fluid flow in the toothing, measure a definite fluid volume during each rotation. Rotating gears through magnetic coupling pass to calculating unit with an indicator.

The following factors- shell material, oval gears and gear wheels and the installation of temperature extension meters with oval gears affect the choice of the operating regime for each standard meter size:

- *high and low temperature regime;*
- *high and extremely high viscosity;*
- *regime at operating pressure up to 10 mPascals.*

Meters for petroleum products PPO andPPV (Fig. 3.44-3.46)

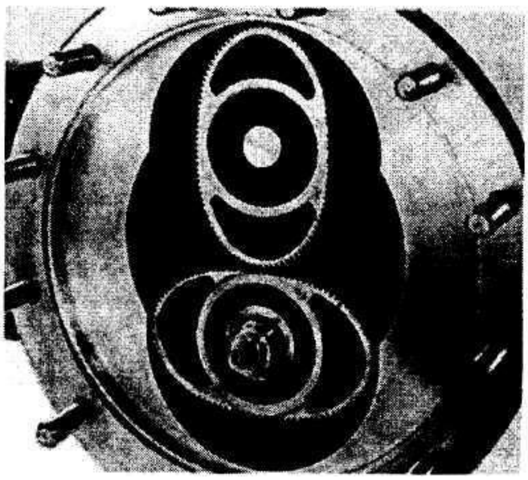


Fig. 3.43. Mass flow meter

Fig. 3.44. Mass flow meter for petroleum products - type ППО and ППВ («Promrpribor». Livn ,Russia)

Mass flow meter- types PPV and PPO are to measure petroleum product volume amount. Mass flow meters include measuring indicator (signal pickup unit with KUP-type controller), remote information control "Vesna". The meter connection is coupling according to GOST ***12820-80*** and depending on passage vent and operating pressure, as well as, choke nipples M42x2 for meter PPO-25-1,6.

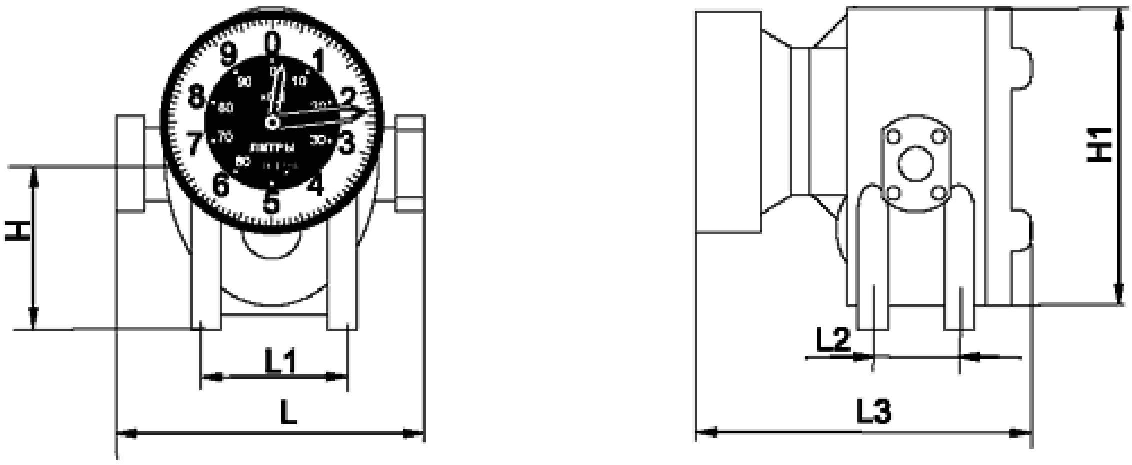


Fig. 3.45. Overall and linking dimensions of PPO

Fluid meters with oval ППО- type and screwed ППВ- type gears are applied to measure total and single amount of light petroleum products, associated gas and other non-aggressive fluids. Technical requirements for PPO and PPV meters are depicted in Table 3.13, overall dimensions in Fig. 3.45, 3.46 and Table 3.14.

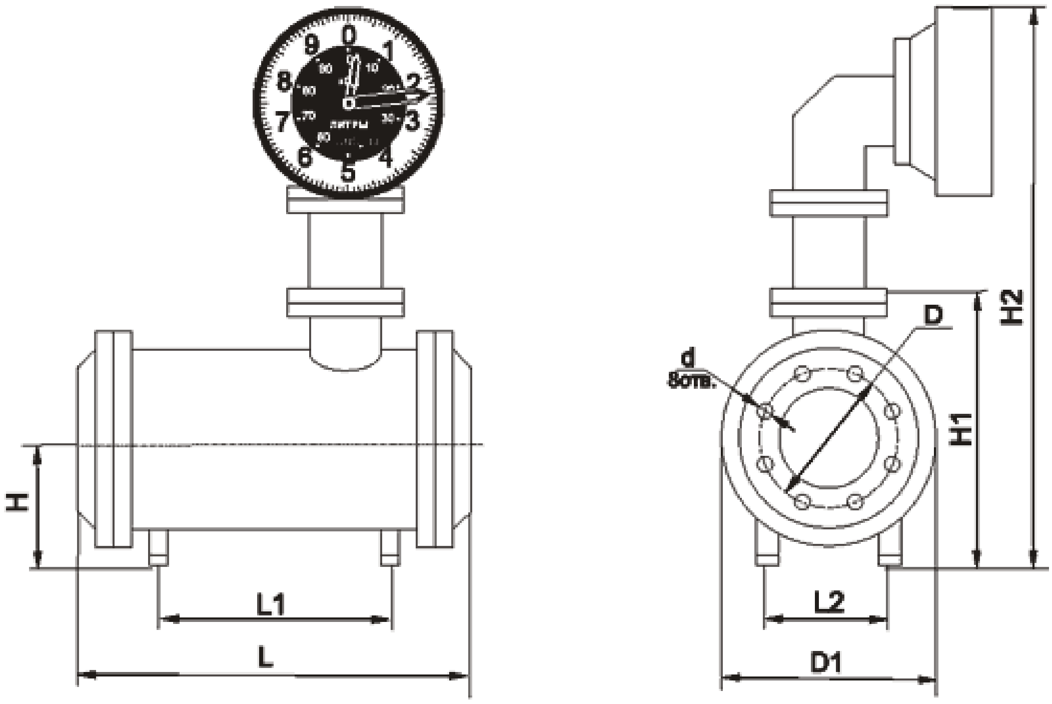


Fig. 3.46. Overall and linking dimensions of PPV

Table 3.13

Technical Requirements of meters PPO and PPV for petroleum products

Type	Measuring indicator divisions, l		Dy, mm	Operating pressure, mPas	Temperature of measured fluid °C	Accuracy grade	Viscosity range for measured fluid, mm^2/s								
							0,55-6,0								
							Output, m^3/hr.								
	mech.	elect.					min	nom	max	min	nom	max	min	nom	max
PPO-25/1,6	0,1	0,1	24	1,6	from -40 to +60	0,25	1,0	3,6	7,2	0,72	3,6	6,0	0,6	3,6	6,0
						0,5	0,72	3,6	7,2	0,72	3,6	7,2	0,72	3,6	7,2
PPO-40/0,6	1	1	40	0,6		0,25	5	18	25	5	18	25	5	18	25
						0,5	2,5	18	25	2,5	18	25	2,5	18	25
PPV-100/1,6	10	1	100	1,6	from -50 to +50	0,25	18	120	180	18	120	180	18	120	180
						0,5	15	120	180	15	120	180	15	120	180
PPV-100/6,4	10	1	100	6,4		0,25	18	120	180	18	120	180	18	120	180
						0,5									
PPV-150/1,6	10	1	150	1,6		0,25	30	250	420	30	250	350	30	250	300
PPV-150/6,4	10	1	150	6,4		0,5									

Table 3.14

Overall dimensions

Тип счетчика	L	L1	L2	L3*	H	H1	d	D	H2	D1
ППО-25/1,6	190	80	25	265 (336)	70	136	**	**	–	–
ППО-40/0,6	270	125	75	305 (376)	137	270	Ф14	Ф100	–	–
ППВ-100/1,6	480	400	140	–	130	348*	M16	Ф180	610	Ф255
ППВ-150/1,6	780	280	280	–	220	516*	M30	Ф280	780	Ф390

*(*depends on package; **according to GOST 12820-80)*

Gas rotameter with identical octa-shaped rotors are applied to measure *transporting gas volume.* (Fig. 3.47).

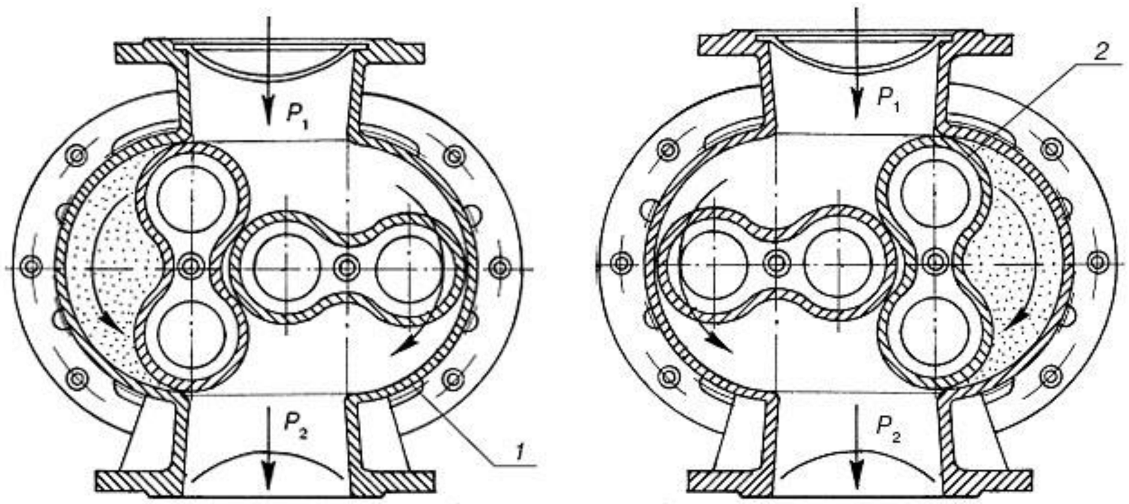


Fig. 3.47. Rotameter with octad-shaped rotors: 1) shell; 2) rotor

One rotor rotation displaces 4 shaded volumes as seen in Fig 3.47.Thick lines indicate those rotor sections for precise processing as along these lines junction rotor point slides during their running-in. Gas leakage depends on the gap between the shell and rectangular sections, located at the largest rotor diameter. The gap ranges from 0.04 to 0.1mm depending on the meter type. The sharp section edge facilitates meter self-refining. Previous meters had the following characteristics: nominal flow $\boldsymbol{Q_н}$ from 100 to 10 000 m^3/hr, where measured volume increased up to 1100 dm^3 , rotation velocity at $\boldsymbol{Q_н}$ decreased up to 150 rotation/min. [31,32].

Example.

RVG Meter

RVG gas rotameters (Fig. 3.48) (*«Gaselektronika», Arzamas* (now «ELSTER Gaselektronika»). These meters are used in the following industries: natural gas, chemical and heat-and-power.

Fig. 3.48. Meter RVG («Gaselektronika», Arzamas, Russia)

RVG meters– devices to measure oil or gas (natural, inertia, propane, air) volume. Rotor meter has a rotatable turbine wheel positioned to intercept fluid flowing through a line. The wheel rotates at a speed proportional to the fluid velocity. The rotation of the wheel is sensed by a pickup coil, which provides pulses to actuate an indicator. Electronic compensators EK-88, TC-90 and others are applied to alter the measurement value to normal volume. Gas flow increases the differential pressure at the meter inlet and outlet, which in its turn, causes the rotor to rotate, connected by high-accuracy synchronizing sprocket wheels. The rotors spin proportionally in opposite directions. There is no metal to metal contact between rotors and shell (frame). Gas flows in and out of the space between the rotor and shell (frame).

Multiple-speed gearbox reduces rotor rotation, and then through magnetic collar passes to 8-discharge measurement connector end. *RVG* meters are used instead of turbine flow meters in the flow rate range of 0,8 to 400 m^3/hr. High design quality guarantees high measurement accuracy, performance reliability and lifetime service.

RVG meters include two low-frequency impulse E-1 sensors (magnetic contact). RVG meters can include medium- frequency impulse E300 and high-frequency impulse A1K. Due to the combination of different frequency impulse meter types, *RVG* gas meters are applied in automatic monitoring and controlling systems. The advantages of *RVG* meters are the following: low rotor persistence at variable loadings (flow rate); low pressure loss (20…40 mm); no straight pipeline section for installation; horizontal and vertical section installation. The following requirements are to be considered: regular control and maintenance of oil level; application of filters or conical screen to catch particles of more than 0.25mm; additional filter to catch particles of more than 0.05 mm if gas is contaminated. Major technical requirements of *RVG* meters are:

- *gas flow,* m^3*/hr.: 0,8-400*
- *maximum operating pressure, mPascals: 1,6*
- *susceptibility threshold,* m^3*/hr.: 0,1*
- *ambient temperature, °C: -30 ... +70*
- *measured fluid temperature, °C: -20 ... +60*
- *Error from* $0,1Q_{nom}$ *to* Q_{nom}*: ± 1 %*
- *Intermediate check-interval, years:* 4

RVG (turbine) meters operate in the horizontal and vertical positions, where the end rotates at 360°. The shell is aluminum, anodic coating solid with two sections for pressure selection and two cylinders for temperature indicators. Gas flow measured by *RVG* meter is depicted in Table 3.15; Overall dimension and linking sizes- Fig. 3.49 and Table 3.16.

Table 3.15

Gas flow, measured by RVG meters

Model	V,dm^3	Susceptibility threshold, m^3/hr	Flow range Qmax/Qmin	Qmax, m^3/hr
G16	0,56	0,1	1 : 20	25
G25	0,56	0,1	1 : 20; 1 : 50	40
G40	0,56	0,1	1 : 20; 1 : 50	65
G65	0,56	0,1	1 : 20; 1 : 50; 1 : 100	100
G100	0,56	0,1	1 : 20; 1 : 50; 1 : 100; 1 : 160	160
G100	1,07	0,16	1 : 20; 1 : 50; 1 : 100	160
G160	2,01	0,25	1 : 20; 1 : 50; 1 : 100	250

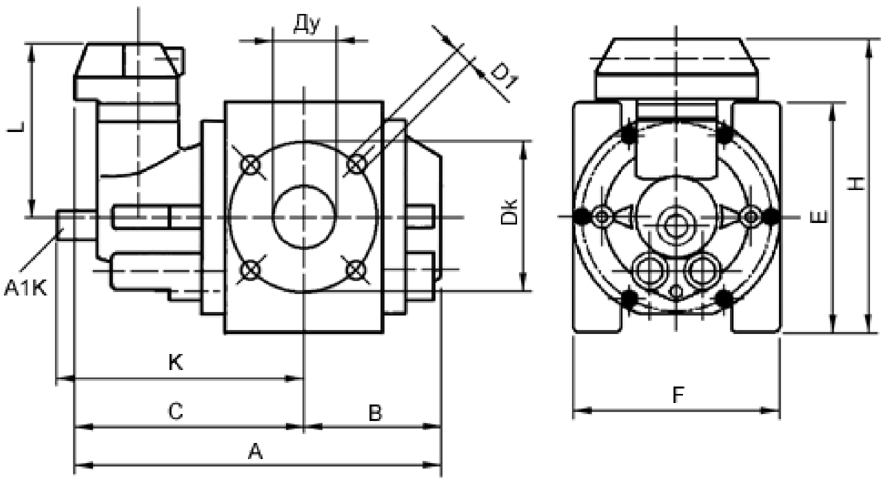


Fig.3.49. Overall dimension and linking sizes

Table 3.16

Overall dimension and linking sizes (mm)

Meter type	Dy	A	B	C	H	Dk	D1	E	K	L	F	Weight, Kg.
G16, G25, G40, G65	50	303	115	189	238	125	4 × M16	180	240	144	171	13
G100	80	403	165	239	238	160	8 × M16	180	290	144	171	17
G160	80	436	189	247	278	160	8 × M16	220	298	168	241	27
G250	100	496	219	277	278	160	8 × M16	220	328	168	241	37

Approximate RVG selection method:

$$Q_{p_{\min}} = Q_{c_{\min}} \frac{P_c}{P_{\text{àáñ}_{\max}}} \text{ и } Q_{p_{\max}} = Q_{c_{\max}} \frac{P_c}{P_{абс._{\min}}}, \quad (3.22)$$

where $\boldsymbol{Q_{p_{\min}}}$ *,* $\boldsymbol{Q_{p_{\max}}}$ *– minimum and maximum gas flow under operation conditions;*

$\boldsymbol{Q_{c_{\min}}}$*,* $\boldsymbol{Q_{c_{\max}}}$ *– minimum and maximum gas flow under standard conditions;*

$\boldsymbol{P_{абс}}$ $(P_{изб} + P_c)$ *– absolute gas pressure in the gas pipeline,mPascals;*

$\boldsymbol{P_c}$ *= 0,1 mPascals – standard atmosphere.*

According to $\boldsymbol{Q_{p\ max}}$ the RVG type is determined, and $\boldsymbol{Q_{p\ min}}$ – flow measurement range.

3.2.3. Coriolis (mass) flowmeters

Flow meters employing the Coriolis principle have recently become of primary interest due to their ability to measure mass fluid flow rate excluding an intrusive device in the flow stream. Coriolis type mass flow meters operate on the principle that fluent material passing through a conduit tubing, when exposed to a deflection (oscillation) transverse to the direction of flow, reacting with a measurable force (the Coriolis force) on the walls of the tubing.

All bodies on the Earth surface deflect due to the east-direction Earth rotation. As to flowmeters, the effect can be demonstrated by flowing water in a loop of flexible hose that is «swung» back and forth in front of the body with both hands. Because the water is flowing toward and away from the hands, opposite forces are generated and cause the hose to twist. (Fig. 3.50, 3.51, 3.52)

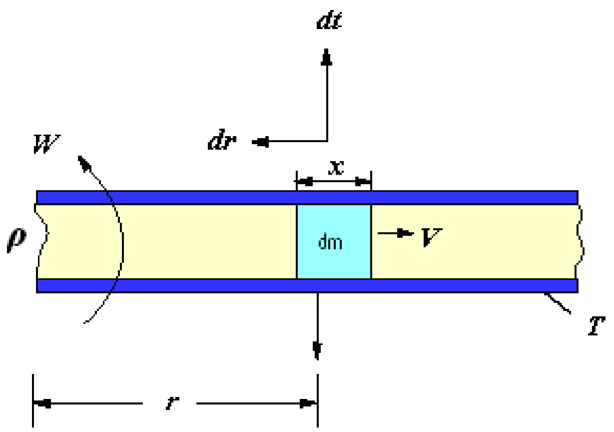


Fig. 3.50. Coriolis Principle: Mass flow rate = Fc/(2wx); Fc – Coriolis force

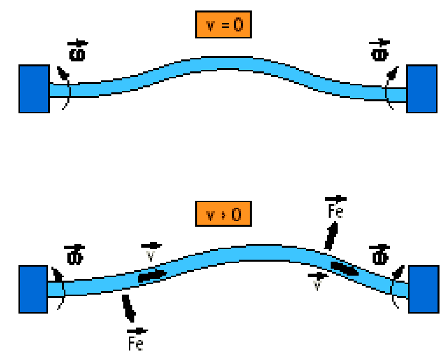


Fig. 3.51. Vibration («swinging») of the tube

Fig. 3.52. Coriolis flowmeters

In a Coriolis (mass) flowmeter, the »swinging» is generated by vibrating the tube(s) in which the fluid flows. The amount of twist is proportional to the mass flow rate of fluid passing through the tube(s). The twist force reacting on the tube is in right-way direction to velocity vector. Coriolis vector forces and fluid velocity vector is in one plane (horizontal).

The flow tube is mounted on a supporting structure with end connections. A conduit is excited at resonance in one of its natural vibration modes as a material flows through the conduit, and motion of the conduit is measured at points along the conduit. Excitation is typically provided by an actuator that perturbs the conduit in a periodic fashion.

There are two basic types of Coriolis (mass) flowmeters, one employing a more or less straight Coriolis measuring tube, the other a looped Coriolis measuring tube. Another differentiating feature - there are mass flowmeters with only one Coriolis measuring tube or with two Coriolis measuring tubes, in the latter case, permitting either parallel or in-line fluid flow. Coriolis mass flowmeter measure material flow and generate information such as mass flow rates, density, pertaining to the material flow. Sensors and a Coriolis mass flowmeter transmitter are used to measure the twist and generate a linear flow signal (4…20 мА).

Advantages. High accuracy flowmeter with a wide range of application – commercial fluids and compressed gas. Many applications for Coriolis mass flowmeter are found in gas industry- for natural gas volume rate. In this case, the gas is compressed to 20 MPascals (200 bar) and for this method.

Disadvantages. Special attention is paid to installation because pipe vibration can cause operation problems. Measuring gas \ vapor flow with Coriolis (mass) flowmeters is acceptable, but flow rates tend to be low in the flow range (where accuracy is degraded). In gas \ vapor applications, large pressure drops across the flowmeter and its associated pipe can occur.

There is a wide range of manufacturers in flowmeter production: Krohne (Germany), MicroMotion (USA), Endress+Hauser (Austria).

Example.

Coriolis (mass) flowmeter МАСК

Fig. 3.53. Coriolis mass flowmeter МАСК («MASK»,Moscow)

Mass flowmeters МАСК (Fig. 3.53) are Coriolis mass flowmeter type to measure gas flow (natural and compressed) in closed pipelines.

Specific features:

- *measurement in mass units (kg., m.);*
- *measurement accuracy independent of operating pressure, density and viscosity;*

- determining dose for measuring product and signal switching.

Relative measurement error in %: 0,5. Measuring fluid pressure, mPascals not more than 6,4. No requirements for straight measuring tube before and after primary transmitter.

3.2.4. Vortex Flowmeters

Vortex flowmeters measure the vibrations of the downstream vortexes caused by the barrier placed in a moving stream. The vibrating frequency of vortex shedding can then be related to the velocity of flow.There are three major classes:

- *when a fluid steadily over a isolated cylindrical solid barrier, vortices are shed on the downstream side. The vortices trail behind the cylinder in two rolls, alternatively from the top or the bottom. (called von Karman vortex street\ effect);*
- *vortices like «mini-tornadoes» are shed into the wide area of the pipe, wobbling and creating pressure fluctuations;*
- *vortices as a stream from the opening, creating oscillation and pressure fluctuations.*

Vortex flowmeters are based on the principle called the von Karman effect. This principle states that flow around a bluff body will generate vortices on alternate sides of the bluff body. This piece of material extends vertically into the flowstream. Flow velocity is proportional to the number of vortices generated (Fig. 3.54). The Karman street has two significant influences on the principle of operation of vortex flowmeters:

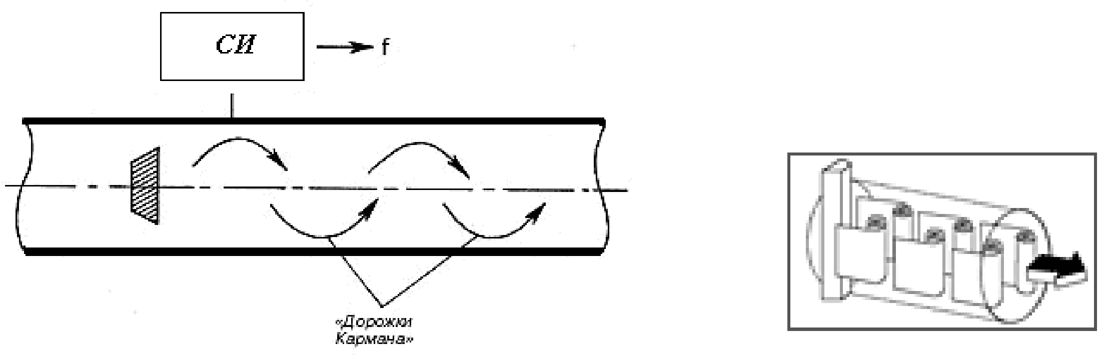


Fig. 3.54. Vortex flow meter: SI – impluse meter unit

- the frequency of vortex shedding is definite and is related to the Reynolds number (flow velocity, viscosity of fluid ,etc.)

- the frequency of vortex shedding is the same as the vibrating frequency of the cylinder induced by the flow.

If the Reynolds number ranges from 2x104 to 7x106 the proportional coefficient between vortex frequency and flow velocity is independent of this number. Vortex flowmeters have high accuracy in measuring any fluid flow velocity.

These flowmeters include multi-staged flow transmitters. The following stages are: 1) generation of vortice or stream oscillation creates pressure pulsation or velocity, the frequency of which is proportional to flow volume; 2) this pulsation is converted to a pulse signal – i.e. electrical one. These transducers are piezo elements (pressure), heat loss anemometer (temperature), strain sensor (strain), ultrasonic velocity transducers, etc.

Advantages: no troublesome moving parts, flow transducer simplicity and reliability, readings independent of pressure and temperature, wide range of measurement up to 15...20 (in some cases), linear scales, extremely accurate and repeatable measurements (errors ±0,5…1,5%), frequent measuring signal, stability of readings, relatively simple measuring scheme, possible universal calibration. Low to medium initial set up cost and not much maintenance needed when used in clean flow conditions.

Disadvantages: low to medium pressure drop due to the obstruction in the flow path (up to 30-50 kPascals) and limitation in application; handling low flows (fluid speed is highly important, since their proper operation required the generation of vortices); in tube diameters from 25 to 150...300mm.- unsteady generation of vortices. Heavy particle suspension, contaminated and aggressive substances can cause sensing inaccuracies for non-obtrusive metering systems. If the flowmeter set signal unit is heat loss anemometer (example, flowmeter ВРСГ , company "Irvis"), then it becomes volatility; if piezo elements (example, flowmeter, company "Sibneftavtomatika", company "Globus") – troublesome factors in protection under external mechanical; vibration of the pipeline [33]. Accuracy is critical in measurement [34]. The well-known company Endress+Hauser produces vortex flowmeter series Prowirl.

Example.

SMART vortex flowmeter EMIS VIKHR 200, Cheljabinsk

The above-mentioned vortex flowmeters measure the following parameters:

- *conductive liquid flow (example, water or water-solutions);*
- *Non-electroconductive liquid flow(ex. refined petroleum products or spirit);*
- *Aggressive fluid fluid (ex. sulphuric acid or alkali) ;*
- *Liquid + liquid mixture flow (ex. oil = water);*
- *Natural and technical gas flow (ex.compressed air);*
- *Dangerous gas flow-hydrogen and oxygen of wet and dry vapour.*

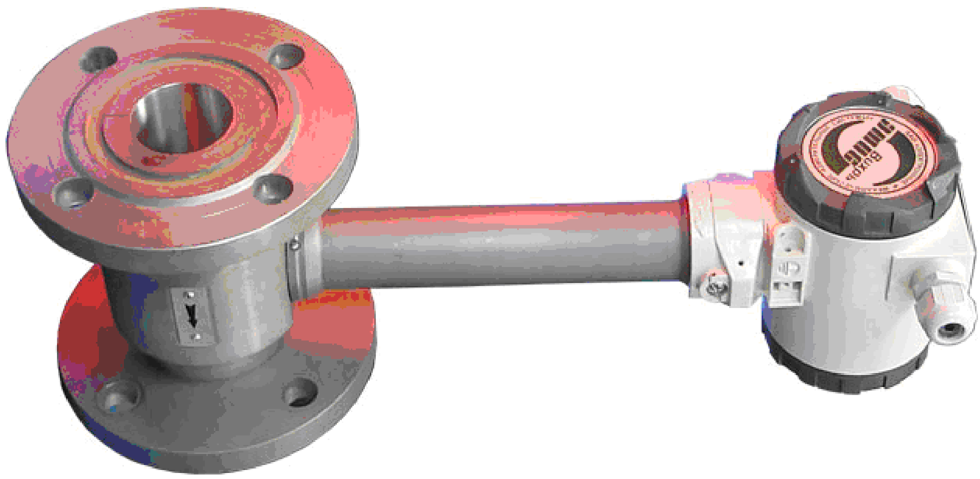


Fig. 3.55.Vortex flowmeter EMIS VIKHR 200

The above-mentioned vortex flowmeters measure the following parameters:

- *conductive liquid flow (example, water or water-solutions);*
- *Non-electroconductive liquid flow(ex. refined petroleum products or spirit);*
- *Aggressive fluid fluid (ex. sulphuric acid or alkali) ;*
- *Liquid + liquid mixture flow (ex. oil = water);*
- *Natural and technical gas flow (ex.compressed air);*
- *Dangerous gas flow-hydrogen and oxygen of wet and dry vapour.*

Among vortex flowmeters vortex transducer AMISC-VIKHR is the most universal one. The only limitation is fluid viscosity.

Vortex transducer EMIS VIKHR offers:

- *wide dynamic range up to 1:40;*
- *smart signal processing;*
- *additional temperature error correction;*
- *high vibration stability ;*
- *resistance to hydro- and thermo impact;*
- *life- term and reliability;*
- *high stability in metrological characteristics;*
- *no maintenance during performance;*
- *Intermediate check-in interval – 3 years;*

How the vortex flowmeters work. The vortex flow meter is based on the vortex shedding principle. As fluid moves around a body, vortices (eddies) are formed and move downstream. They form alternately, from one side to the other, causing pressure fluctuations. Flow velocity is proportional to the number of vortices generated (principle called the von Karman effect). These are sensed by a piezoelectric element in the sensor tube and are converted into pulse signals. The above-mentioned vortex flowmeters are called «flexural strain vortex flowmeters». The piezo crystal (element) design truncates harmful vibration signals and temperature at generation stage 1; while at stage 2 – generation occurs in the electronic block unit: signal spectrum processing, harmful harmonic curve truncation and signal correction according to temperature and Reynolds number.

Technical requirements of vortex flowmeter AMISC-VIKHR 200 are depicted in the following table 3.17; liquid flow range – Tables 3.18, 3.19.

Table 3.17

Specifications of vortex flowmeter AMISC-VIKHR 200

Parameter	Value
Measuring medium	Liquid, gas, vapor
Ambient temperature	from -40 to +550 C from -40 to +70 C
Allowable pressure	Up to 4 mPascals
Liquid measurement accuracy	0,6% from 0,1Q_{max} to Q_{max} / 1,35% up to 0,1Q_{max}
Outlet reference diameter	25/32/50/80/100/150/200/250/300 mm
Gas and vapor measurement accuracy	1,35% from 0,1Q_{max} to Q_{max} / 2,5% up to 0,1Q_{max}
Outlet signals	Frequency 0-1000(10000)Hz; Current 4-20 milliampere ; Digital RS-485 Modbus RTU
Protection from explosion	ExibIIB(IIC)(T1-T5)X
Vibration stability	Vibration frequency from 10 to 100 ГHz
Supply voltage	12…36 V
Intermediate check-in interval	3 years
Warranty period	18 months

Table 3.18

Liquid flow range of vortex flowmeter AMISC-VIKHR 200

Conditioned diameter Dy, mm	Liquid flow, m^3/hr	
	Minimum	Maximum
25	0,5	13
32	1	28
50	2	60
100	8	240
150	18	540
200	34	1000
250	60	1500
300	95	2100

Line connection (installation) in straight pipelines depends on the curvature character or stop valve type.

- 10dm internal diameter (Dy) before the transducer and 5Dy after it (in most cases);
- by welding in pipelines with diameter from 25 to 300 mm.; if pipeline diameter is more than 300mm – local pipeline tapering;
- in different pipeline series;
- no limitations in rugosity;
- on horizontal, vertical and inclined pipeline areas;
- stream rectifier reduces straight pipeline sections up to 8Dy;
- in flanged AMISC-VIKHR – flange to flange connection under the following conditions: high pressure (more than 2.5 mPascals) and pipeline diameter more than 200mm;
- «sandwich» connection, where flowmeter is between collars (flanges) by pinning

Electrical link-up

Flowmeter AMISC-VIKHR model series ЭВ-200 includes frequency (impulse) digital RS485 Modbus RTU and analogous current one 4-20 milliampere for output signals. Connector block – Fig. 3.56, contact list o connector blocks – Table 3.20.

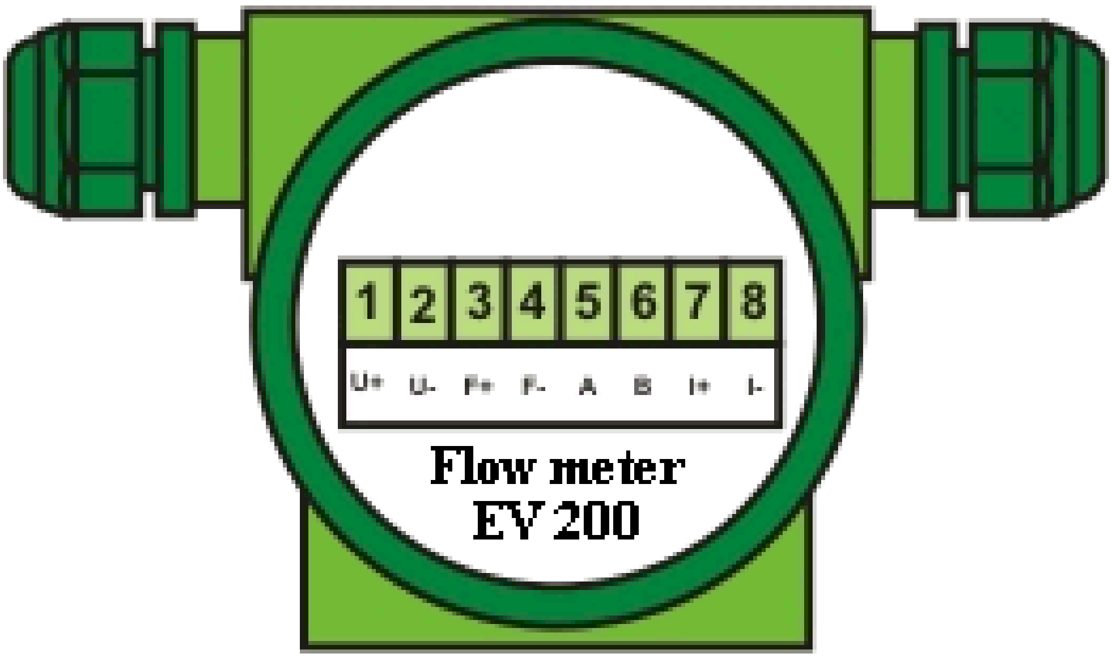


Fig.3.56. Flow meter connector block

Table 3.19

Gas flow rate range for vortex flowmeter EMIS VIKHR 200

Diameter Dy, mm	Gas and vapor flow (m^3/hr) at different absolute pressure values								
	100 kPas.	300 kPas	600 kPas	900 kPas	1600 kPas	2100 kPas	2600 kPas	3600 kPas	4100 kPas
25	9…130	6,5…130	4,6…130	4…130	3,5…130	3,5…128	3,5…116	3,5…98	3,5…92
32	18…220	12…220	9…220	7…220	7…220	7…220	7…214	7…182	7…171
50	50…530	23…530	16…530	13…530	13…530	13…492	13…409	13…348	13…326
80	115…1300	64…1300	45…1300	37…1300	37…1300	37…1300	37…1127	37…958	37…898
100	190…220	96…2200	68…2200	56…2200	56…2200	56…2052	56…1708	56…1451	56…1360
150	440…5050	229…5050	162…5050	132…5050	132…5050	132…4878	132…4059	132…3449	132…3232
200	760…8800	401…8800	283…8800	231…8800	231…8800	231…8555	231…7118	231…6049	231…5669
250	1210…14000	631…14000	446…14000	365…14000	365…14000	365…13477	365…11213	365…9530	365…8930
300	1750…20000	914…20000	646…20000	528…20000	528…20000	528…19512	528…16235	528…13797	528…12928

Table 3.20

Contact list of flow meter connector block

Contact number	Meaning	Usage
1	U+	+ power supply
2	U-	- power supply
3	F+	+ frequency outlet
4	F-	- frequency outlet
5	A	Contact A digital outlet signal
6	B	Contact B digital outlet signal
7	A+	+ current outlet
8	A-	- current outlet

Power supply from DC (direct current) and proper connection to recording unit is depicted in the following diagrams. Two or more outlet flowmeter signals are allowed simultaneously.

Power supply for flowmeters. Power supply –DC from 12 to 30V for flowmeter EMIS VIKHR (example, power unit BP-63), where recommended power supply is 24V. Power supply is more than 0.75 watt. Flame safety flowmeters EV 200-ExB and EV -200-ExC work at power supply 24 watts, such as ExiaIIB and ExiaIIC, respectively. (example, spark-proof power units ЭМИС БРИЗ).

Flowmeter connection to frequency output. is «open accumulator». General transducer flow scheme EV 200 by frequency output is depicted in Fig. 3.57.

Galvanic isolated battery for flowmeter power supply and frequency signal are recommended. Current in frequency signal is not more than 50 milliamperes. Loading resistance ***Rf*** is according to:

(***U-1)/0,04<RF<>Ом***.

Relation loading resistor ***Rf*** to power supply is depicted in Fig. 3.58.

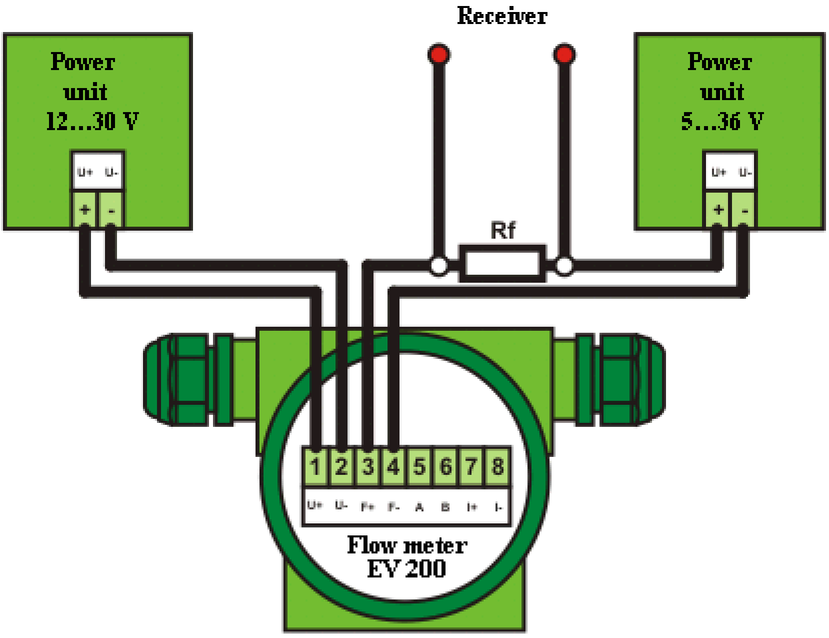


Fig. 3.57. Flowmeter connection to frequency output. ЭВ200

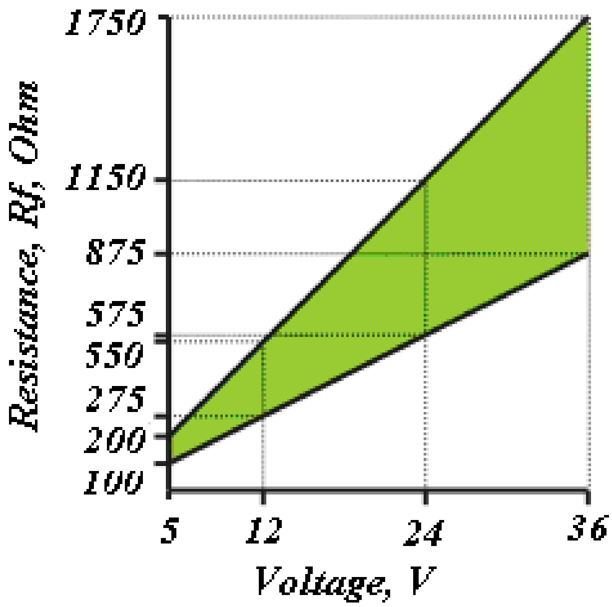


Fig. 3.58. Relation loading resistor Rf to power supply

Scheme of flame safety connection flowmeter transducer EMIS VIKHR by using spark-proof power units is depicted on Fig.. 3.59.

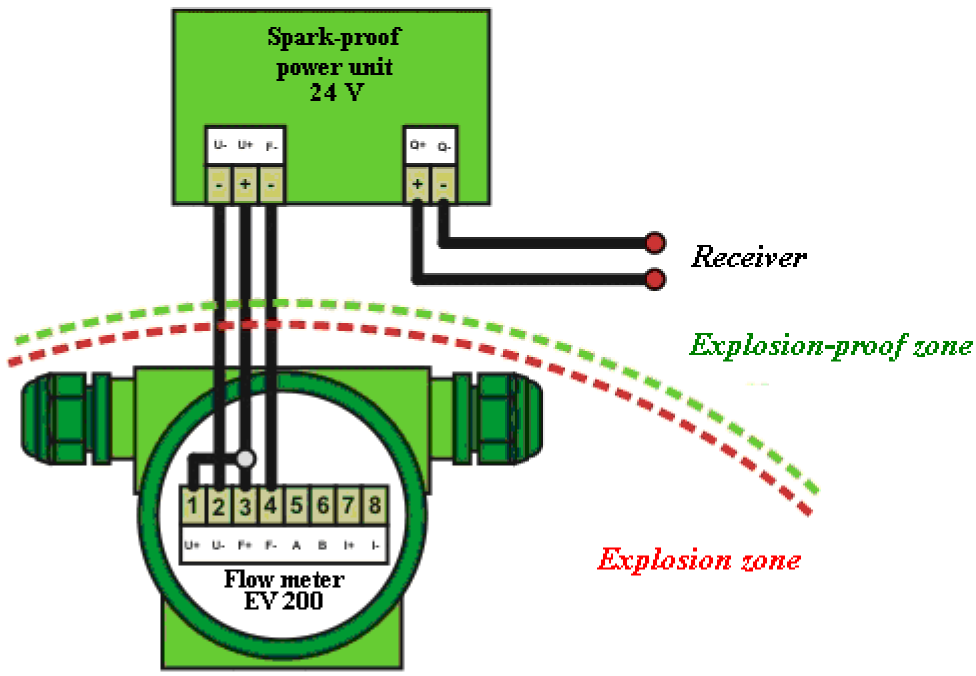


Fig. 3.59. Flame safety connection flowmeter transducer EMIS VIKHR by using spark-proof power units

Flowmeter connection to analog output - standard DC signal of 4…20 milliamperes is linear proportional to current volume flow, with two- wire connection scheme. Typical flow transducer EMIS VIKHR to analog signal output is depicted in Fig. 3.60.

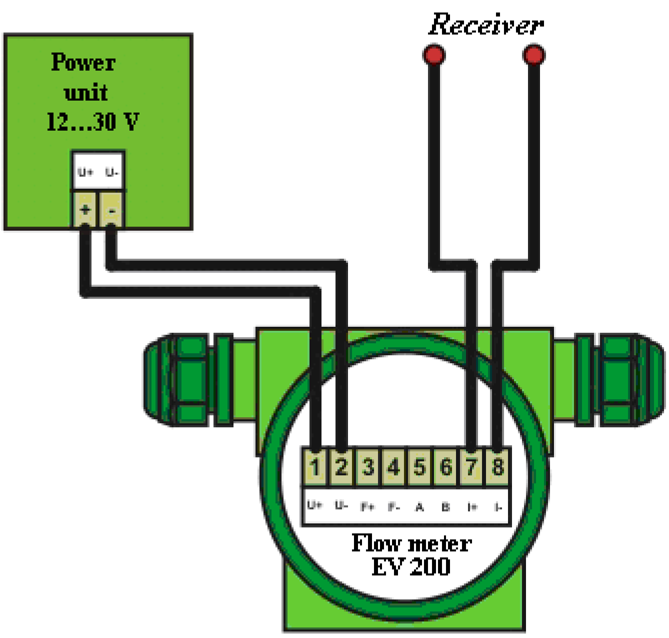


Fig.3.60. Typical flow transducer EMIS VIKHR to analog signal output 4-20 milliamperes

Flowmeter connection to digital output – according to technical requirements EIA/TIA-422-B and recommendations ITU V.11; data communication according to protocol Modbus RTU; possible performance in the network to transmit all measured parameters and exclusion of device configuration. Digital signal flowmeter output Modbus RTU is at the physical level RS-485.(Fig. 3.61) [35].

Connection types to pipeline- the following Table 3.21 depicts the flowmeter variants by connection types to pipelines.

Table 3.21

Flowmeter transducer connection types to pipeline

Symbol	Connection type to pipeline
S	«sandwich »connection type
SU	Standard orifice connection sizes
FST	Flange connection with steel coupling flange
FN	Flange connection with stainless steel coupling flange
M	Coupling connection

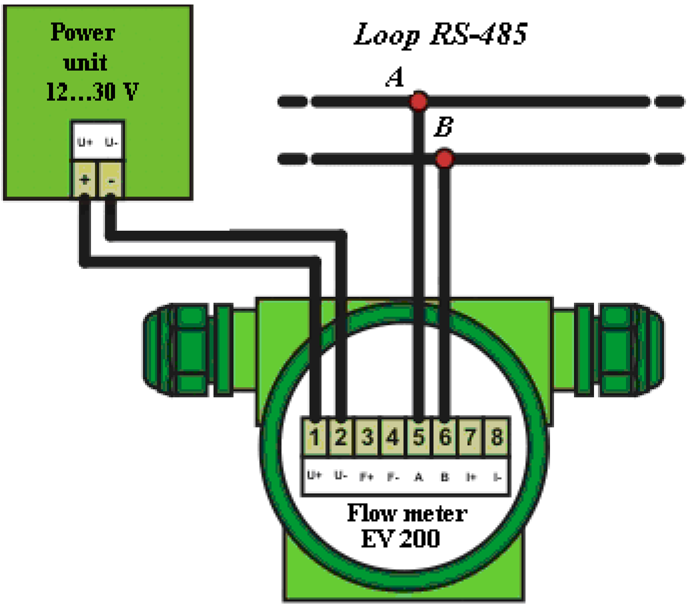


Fig .3.61. Flow meter connection to digital output EV200

3.2.5. Acoustic (ultrasonic) flowmeters

The principle behind the flow meter is acoustic waves with a frequency of 20 kiloHz emitted from one transducer to the other side of the pipe back to the opposite transducer require less time when traveling in the opposite direction. The differential transit time of the signals is proportional to the flow rate of the fluid.

Acoustic meters – a flowmeter used to measure transit times of an acoustic pressure wave with and against the flow (time-of-flight-type meter) to infer pipeline velocity.

Ultrasonic flowmeters - to reflect sonic energy from scatterers in fluid back to a receiver (Doppler –type meter) to measure volumetric flow rate.

Ultrasonic flowmeters include primary ultrasonic flow transducer and signal processing unit. Ultrasonic flowmeter classification (Fig. 3.62)

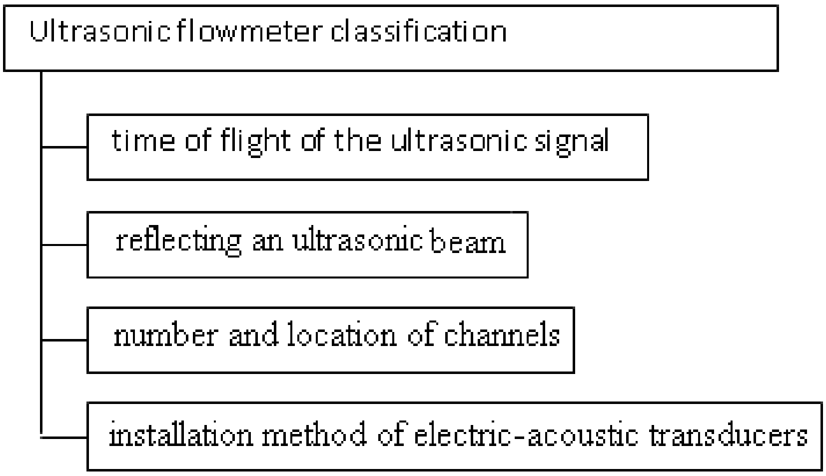


Fig.3.62. Ultrasonic flowmeter classification

Primary ultrasonic flow transducer *– special fabricated straight pipeline, including electric-acoustic transducer.*

Electric-acoustic transducer- a device actuated by power from one system and supplying power to another system- electric power into acoustic power (elastic fluid vibration energy) and visa versa.

Electric-acoustic transducers applied in primary flow transducers are transmitters and receivers of ultrasonic waves.

Signal processing unit – *unit for acoustic signal generation, signal processing and formation of average output signal which is proportional to measured flow. [36,37].*

Transit time measurement (phase method) – the ultrasonic signal transmitted in the flow from a transmitter to a receiver implies that not only the velocity of this signal is determined, but also the flow velocity itself. (Fig. 3.63).

The calculation of ultrasonic signal velocity is the following: downstream- addition; upstream ultrasonic signal velocity- subtraction. The fluid flow velocity is directly proportional to the measured difference between upstream and downstream transit time (volumetric flow).

Averaged flow velocity along the acoustic path is the time travel between pulses transmitted in the direction of and against the gas flow *(time of flight and time of travel).* Another method applied is *phase* or frequency method.

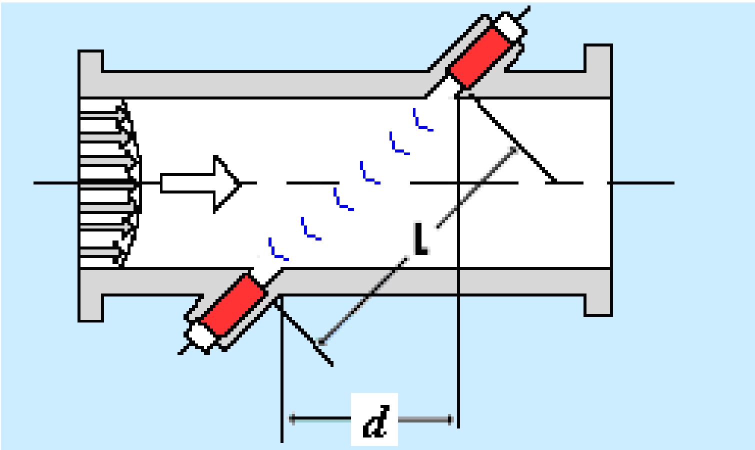


Fig. 3.63. Ultrasonic flowmeter:
L – path length between transducers (acoustic channel); d –acoustic channel plane length, parallel to pipeline axis.

***Acoustic path** – acoustic pulse plane between transducers in the gas flow.*

***Acoustic channel**– measured flow and two transducers, transmitting signals through ultrasonic waves.*

The phase method is based on the following: measurement of phase angles (ultrasonic waves travel in the fluid or gas at a certain angle to the pipeline) of two constant ultrasonic pulses with cyclic frequency $\boldsymbol{\omega}$ and their phase offlap, i.e. the difference between upstream and downstream transit time.

Cyclic frequency respective to wave frequency is determined as:

$$\omega = 2\pi f \,, \qquad (3.23)$$

where $\boldsymbol{\omega}$ *– cyclic frequency, rad/sec.;*

$\boldsymbol{f}$ *– frequency 1/sec.*

If ultrasonic pulses of one and the same distance transmit in the direction of and against the flow, then the phase angles are:

$$\chi_1 = \omega\tau_1 = 2\pi f\tau_1 \text{ and } \chi_2 = \omega\tau_2 = 2\pi f\tau_2 \,, \qquad (3.24)$$

where χ_1 *and* χ_2 *– phase angles, rad.*

Average flow velocity for fluids or gas along the acoustic path is:

$$\bar{u} = \frac{L^2 \pi f}{d} \times \frac{(\chi_1 - \chi_2)}{\chi_1 \chi_2}, \tag{3.25}$$

where ***d*** *– acoustic channel L plane length, parallel to pipeline axis;*

L *– path length of acoustic pulses from both transducers if gas is quiescent state.*

Frequency method is based on the dependence of short pulse frequency difference or ultrasonic wave package to transit time difference measured over the same distance ***L*** in downstream or upstream.

There are short pulses in frequency-impulse flowmeters. These pulses equal ultrasonic transit time in the downstream and upstream direction. So,

$$f_1 = \frac{1}{\tau_1} \text{ and } f_2 = \frac{1}{\tau_2}\text{, but } f_2 - f_1 = \frac{1}{\tau_1} - \frac{1}{\tau_2} = \frac{\Delta\tau}{\tau_1 \tau_2}. \tag{3.26}$$

Average flow velocity along the acoustic path is:

$$\bar{u} = \frac{L^2}{2d}(f_1 - f_2). \tag{3.27}$$

Value infinitesimal $f_1 - f_2$, in frequency flowmeters is a significant disadvantage in accuracy measurement of the gas flow. There are several methods in increasing the frequency difference which is used in ultrasonic flowmeters. In frequency-package flowmeters there are continuous signals during transit time along the acoustic path, instead of short pulses [16, 32, 34, and 37].

Ultrasonic channel beam types

Acoustic beam *– plane where acoustic energy is transmitted from electric-acoustic transducer in one definite direction.*

The ultrasonic channel beams can be straight or reflected (single or frequent) to the internal flowmeter wall. They are in the diametral flowmeter plane or in planes intersecting the bisecant of its cross-section.

Number of ultrasonic channels- There are two types of devices that measure transit ultrasonic velocity: one-channel – ultrasonic in one direction; two-channel – in two directions.

One-channel ultrasonic flow transducer- *flow transducer where one-acoustic channel is used.*

Another term is one-beam or one-path flowmeter. The sonic energy in primary one-channel flow transducer can be transmitted between electric-acoustic transducers as straight or reflected (single or frequent) acoustic beams from the internal measured pipeline wall.

Frequent ultrasonic flow transducer- *flow transducer in which several channels are used to measure the flow.*

Another term is multi-beam or multi-path flow transducers. The sonic energy in primary multi-channel flow transducer can be transmitted between electric-acoustic transducers as straight or reflected (single or frequent) acoustic beams from the internal measured pipeline wall.

Schematic illustration of ultrasonic two-channel phase flowmeter is depicted in Fig. 3.65. The device includes: ultrasonic generator G – power supply for beam pieso-transducers I1 and I2; transducer receivers P1 and P2; phase-shifting unit D1 and D2 to eliminate phase offlaps through transducer channel asymmetry; electronic booster U1 and U2; signal modulator M1 and M2 and measurement device SM to calibrate flow units.

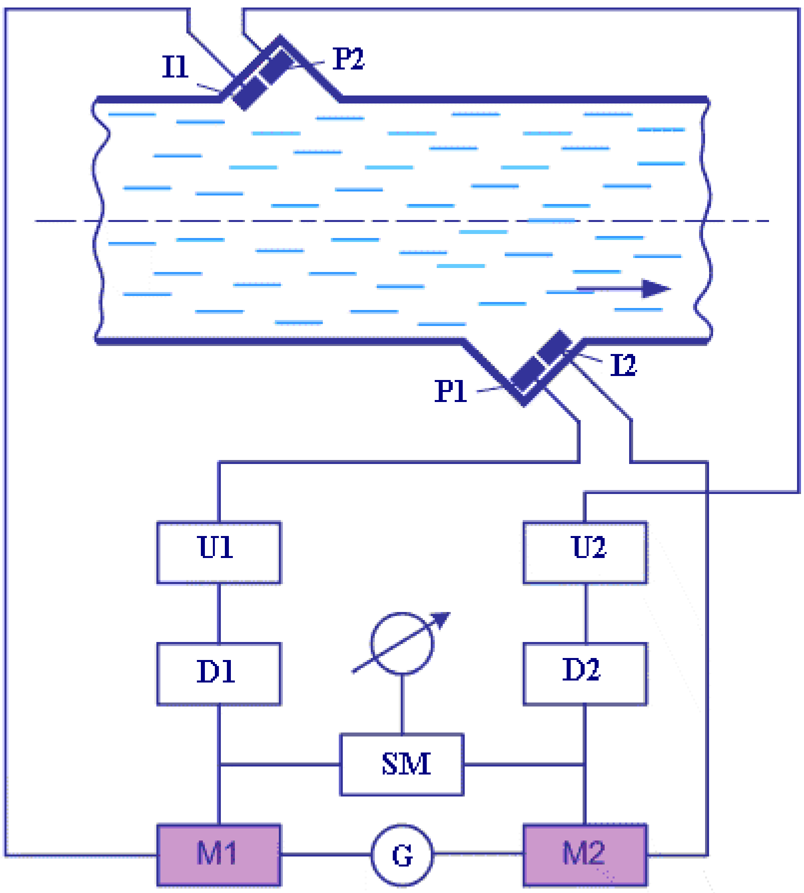


Fig. 3.64. Schematic illustration of ultrasonic meter performance

Piesoelements in the transducers are not only barium titan plates, but also quartz, zircon-titan ceramics and magnetostrictive plates. Ultrasonic pulses are transmitted at an angle to the pipeline axis. In this case, the pulse direction in one channel coincides with the flow direction, while in the other channel -in the opposite direction. When the fluid flow is zero, pulse transit time ***t*** (c) is to distance ***d***.

Acoustic path locations. Ultrasonic flowmeters with one - several reflected or straight acoustic beams are applied widely.

One-channel flowmeters measure gas flow with developed velocity profile and in cases of inaccuracies.

Multi-channel flowmeters minimize effects by flow velocity distribution and Reynolds number. They are highly reliable, if electronic signal processing unit provides (backup) duplication or correction of algorithm calculation when one or a series of electric-acoustic transducers is\are out of operation. Examples of acoustic path locations are depicted in Fig. 3.65, 3.66.

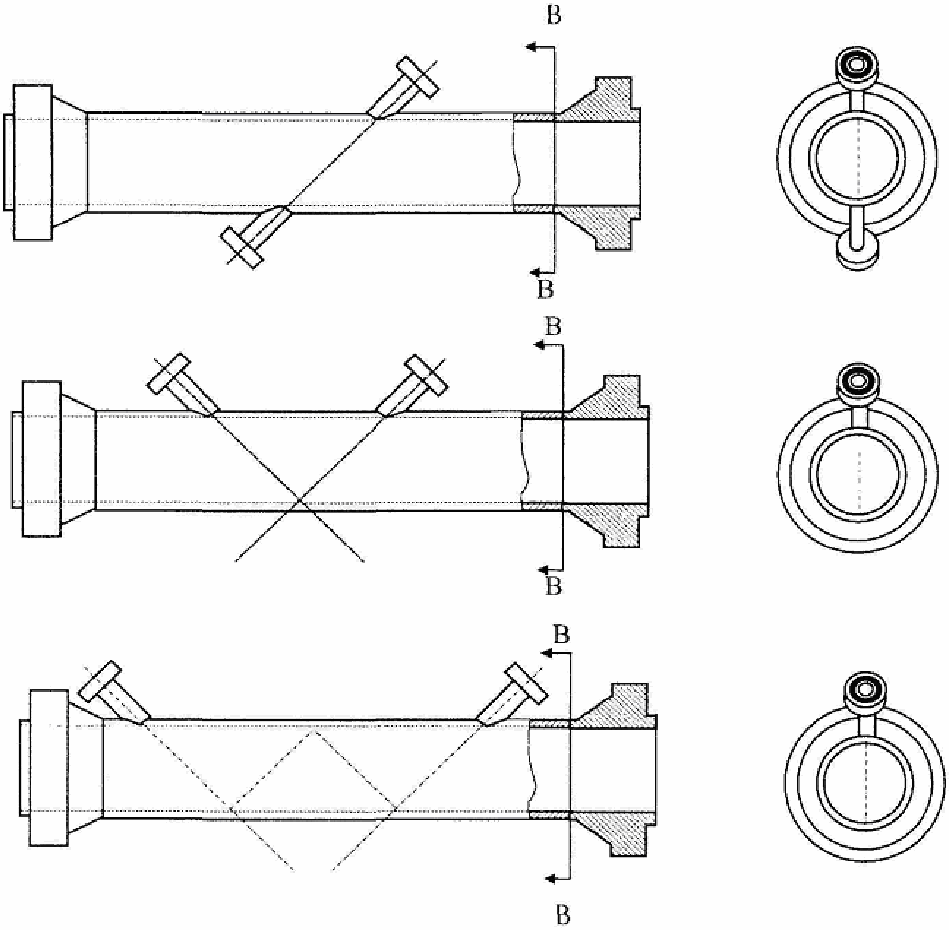


Fig.3.65. Acoustic path locations in one-channel ultrasonic flowmeters

Electric-acoustic transducer installation and configuration- Fig. 3.67, 3.68, 3.69 [36].

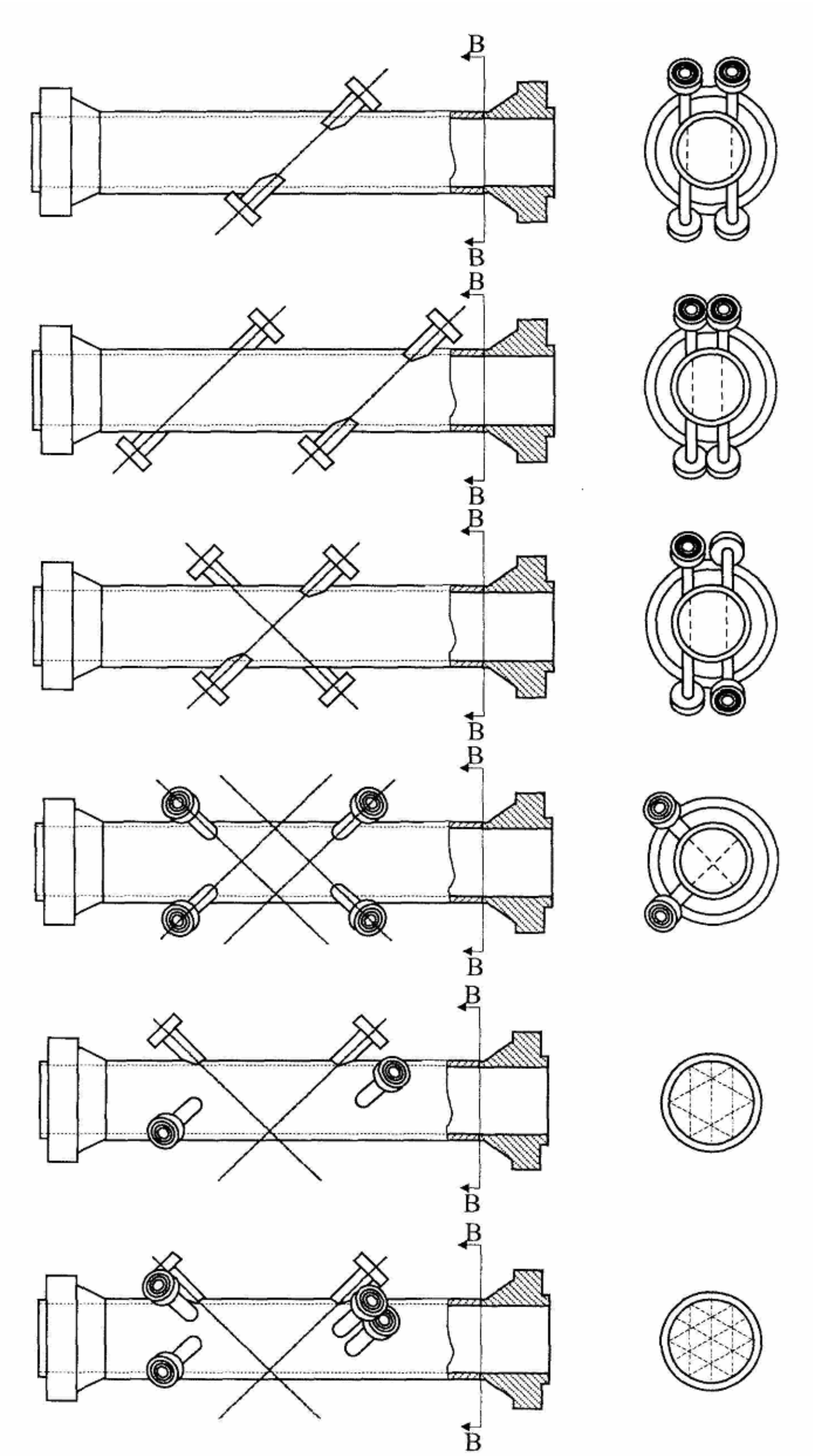


Fig. 3.66. Acoustic path locations in multi -channel ultrasonic flowmeters

Doppler ultrasonic flowmeters operate on the Doppler effect, whereby the transmitted frequency is altered linearly by being reflected from particles and bubbles in the fluid. The net result is a frequency shift between transmitter and receiver frequencies that can be directly related to the flow rate. To use the Doppler effect to measure flow in a pipe, one transducer transmits an ultrasonic beam of = 0.5 MHz into the flow stream. Liquid flowing through the pipe must contain sonically reflective materials (solid particles, entrained bubbles). The movement of these alters the frequency of the beam reflected onto a second receiving transducer. The frequency shift is linearly proportional to the rate of flow of materials in the pipe and therefore, can be used to develop an analog or digital proportional to flow rate.

Ultrasonic flowmeter inaccuracies range from 0.1 to 2.5%, average inaccuracies – 0.5....1%. Above-mentioned flowmeters are extensively used in liquid rather than in gas, as the latter has low acoustic resistance and poor sonic conductivity. Typically ultrasonic flowmeters operate on any pipe diameters, from 10mm and more.

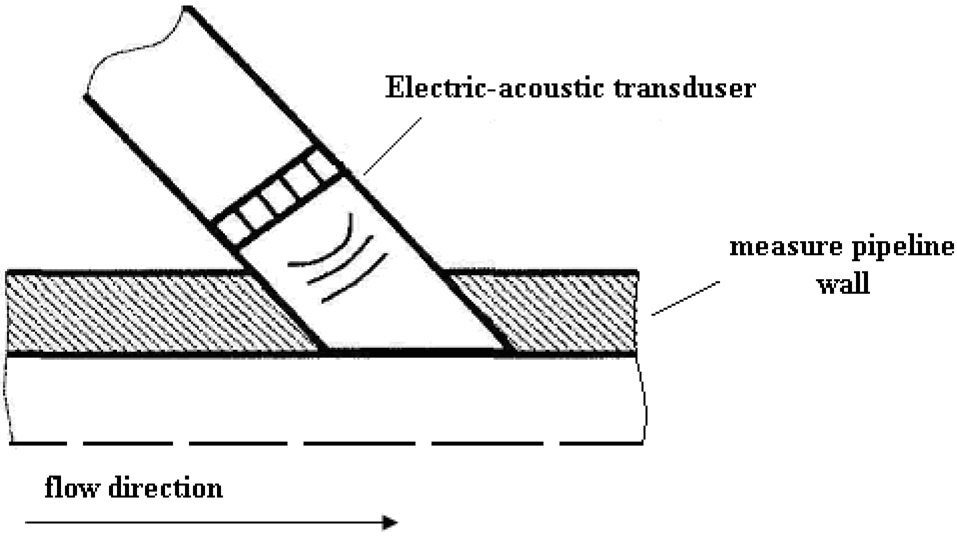


Fig. 3.67. Installation of electric-acoustic transducer outside (above) the measured pipeline

Contemporary flowmeters are various in primary transducer configurations, as well as, applied measurement units. High frequency from 0,1 to 10MHz are used in clean fluid application. In contaminated fluids low frequency (up to several MHz) is used to avoid dispersion and absorption of acoustic waves. The wave length is significantly more than the solid particle diameter or entrailed bubbles. Low frequency is applied in gas flow measurement.

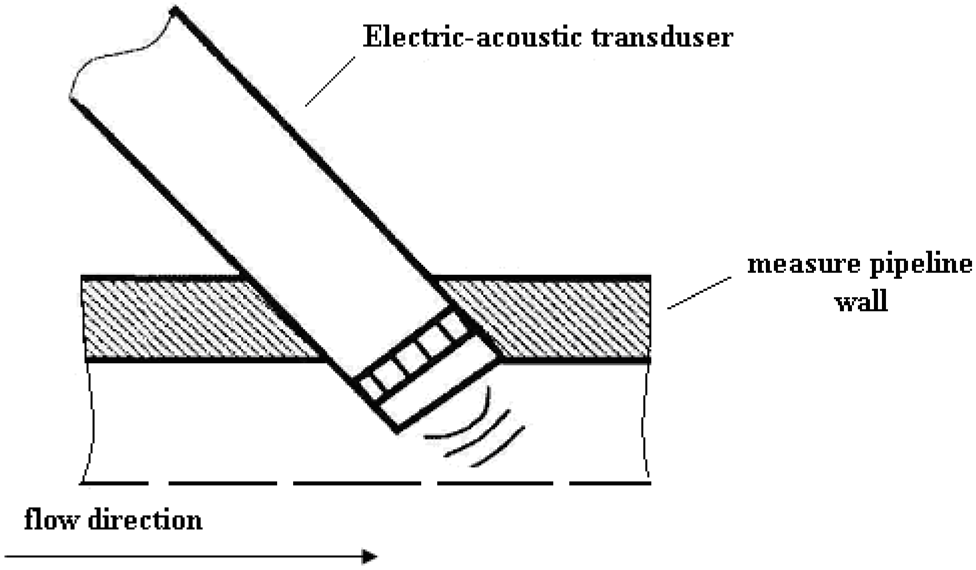


Fig. 3.68. Installation of electric-acoustic transducer at the measured pipeline internal wall

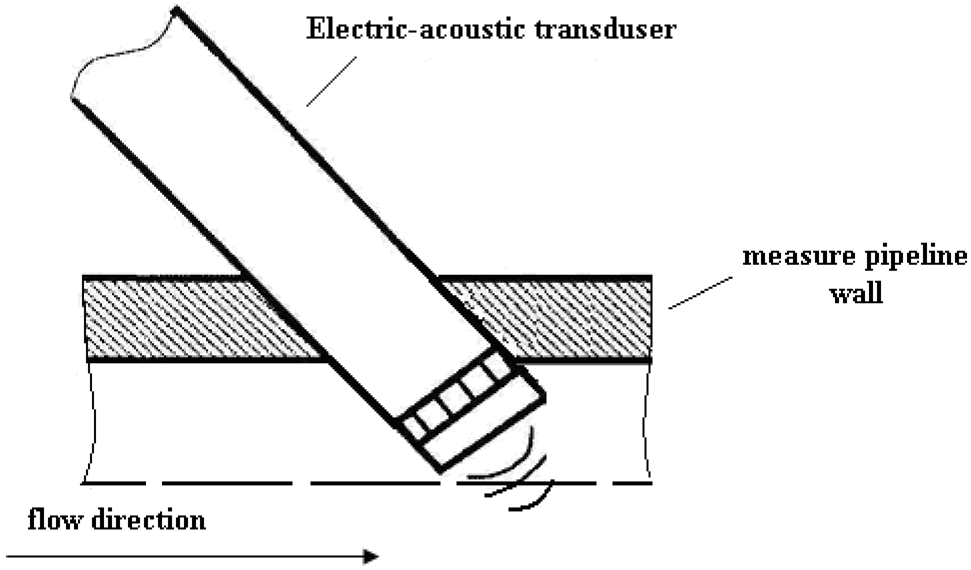


Fig. 3.69. Installation of electric-acoustic transducer in the measured pipeline internal wall

Advantages. Ultrasonic meters have profited from technological advances. There are no moving parts in this meter. Thus, induce no pressure drop and offer high reliability. It has wide fluid flow measurement rangeability, independent power supply and microprocessor units.

Disadvantages: sensitivity to solid particles and gaseous inclusions; to exclude gas flow distortion impact on measurement accuracies multi-beam ultrasonic flowmeters are applied (from two to three beams); sensitivity to composition, density, temperature and transporting fluid, as well as, to environment factors (temperature, ambient pressure).

Example.

Daniel SeniorSonic gas flow meter

Daniel SeniorSonic gas flow meter (Fig. 3.70) is a new industry standard for realtime ultrasonic flowmeters in pipelines with diameter from Dy 80 mm to Dy 600 mm, at pressure up to 10mPascals (100 kgauss\ cm^3). It is a practical solution for the accurate measurement of gas flow applications.

Fig.3.70. Daniel SeniorSonic meter

System overview.

The meter consists primarily of an accurately machined meter body into which eight transducers are fixed. The meter body is purely a piece of steel with no moving parts. The ultrasonic transducers are located in pairs at strategic points across the meter body to provide a velocity profile for the flowing gas.

The Daniel SeniorSonic multipath meter is comprised of the following:

- a high precision flanged meter spool piece
- eight intrinsically safe piezoelectric transducers
- fully digital electrounits (MKII DFI)

The Daniel SeniorSonic gas flow meter (Fig. 3.71) measures the transit times of ultrasonic waves passing through the gas on four parallel planes to accurately determine the mean velocity of the gas flows through the meter. These four planes have been chosen to optimize the accuracy of the measurement regardless of the flow profile. The measurement paths are angled with respect to the pipe axis at 45°. The transit time measurement technique is intrinsically bi-directional with the transit time difference changing sign when the flow direction reverses. This results in the meter having the same calibration in both direction.

Measurement principle.

$$t_1 = \frac{L}{c + u\frac{d}{L}} \text{ and } t_1 = \frac{L}{c - u\frac{d}{L}}, \qquad (3.28, 3.29)$$

$$u = \frac{L^2}{2d} \times \frac{t_1 - t_2}{t_1 t_2}, \qquad (3.30)$$

$$Q = u\frac{\pi D^2}{4} = \frac{\pi D^2}{4} \times \frac{L^2}{2d} \times \frac{t_1 - t_2}{t_1 t_2}. \qquad (3.31)$$

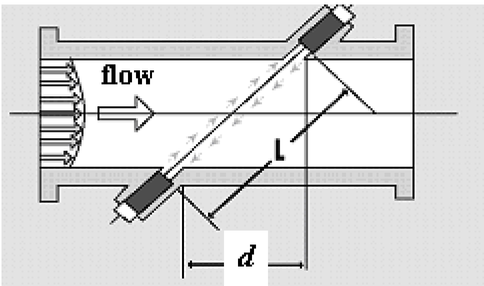


Fig. 3.72.Gas flow measurement by Daniel SeniorSonic gas flow meter: Q – gas flow; t1 and t2 – transit time for signals and data; D –flowmeter diameter

Each pair of ultrasonic transducers measures the velocity along the individual acoustic paths. The velocity on all four chords is then integrated to give the mean velocity of the gas and hence the actual volume flow. The transducers are mounted on the meter body at defined locations. The dimensions ***d*** and ***L*** are precisely determined during the meter fabrication. These measurements together with the electronic characteristics of each transducer pair characterize the ultrasonic flowmeter without the need for a flow calibration. The transit time for a signal traveling with the flow is less than that for a signal traveling against the flow. The difference in these times determines flow velocity.This above-mentioned simple theory demonstrates that flow rate is a function of the physical dimensions of the meter body and the measured transient times. It does not include the local acoustic velocity and consequently does not rely on any other measurements such as pressure, temperature, density or gas composition.

Fey features \ benefits:

-four-path chordal design allows accuracy, stability, redundancy and operational cost savings;

-excellent long-term performance

- provides a direct input of pressure, temperature and gas composition into the meter to act as a redundant flow computer;

-provides faster sampling and output, expandable electronics platform and an optional archive data log (log information).

Daniel SeniorSonic gas flowmeter specifications and flow rate ranges are depicted in the following tables 3.22 and 3.23 [38].

Table 3.22

Specification of Daniel SeniorSonic gas flow meter

Meter Specification	
Flowmeter	Electronic Unit
Application: pipelines for natural gas Dimensions: from 6 to 36 dm (150 – 900 mm). Gas temperature: from -20°C to 60°C , or up to 120°C. Operating pressure range: up to #2500 according to ANSI Meter protection class: according to IP65 by DIN 40050	Input/output serial communication link: RS232/485 direct frequency output (0-5000Hz); indirect frequency output (0-5000Hz); analogue output – 4-20 milliamperes ; received signal data – digital output; inputs for pressure and temperature – digital. Power supply: AC: 115/230 watt ±10%; 47 …63 Hz, 15watt max. DC:: 20 – 28 watt, 15watt max. Performance and storage requirements: working temperature from -40°C to 60°C

Table 3.23

Flow rate measurements of Daniel SeniorSonic meter

Pressure (100 kgs/cm2, excess)	Measurement range						
	Flowmeter sizes, mm /velocity, m/sec.						
	150/35	200/30	250/27	300/27	400/25	500/25	600/23
1	2	3	4	5	6	7	8
Maximum flow rate (thous. m3/hr)							
10	26,04	38,66	54,82	77,83	113,78	178,96	238,13
20	50,75	75,34	106,84	151,67	221,74	348,76	464,07
30	77,25	114,68	162,63	230,86	337,53	530,87	706,39
40	104,46	155,08	219,91	312,18	456,41	717,85	955,18
50	131,33	194,97	276,49	392,49	573,83	902,54	1,200,93
60	162,55	241,31	342,20	485,77	710,21	1,117,04	1,486,35
70	191,38	284,11	402,89	571,93	836,17	1,315,16	1,749,96
80	223,54	331,86	470,61	668,06	976,72	1,536,21	2,044,10
90	257,25	381,91	541,57	768,80	1,124,00	1,767,86	2,352,33
100	289,04	429,10	608,50	863,81	1,262,91	1,986,34	2,643,04
*Minimum flow rate							
10	0,74	1,29	2,03	2,88	4,55	7,16	10,35
20	1,45	2,51	3,96	5,62	8,87	13,95	20,18
30	2,21	3,82	6,02	8,55	13,50	21,23	30,71
40	2,98	5,17	8,14	11,56	18,26	28,71	41,53
50	3,75	6,50	10,24	14,54	22,95	36,10	52,21
60	4,64	8,04	12,67	17,99	28,41	44,68	64,62
70	5,47	9,47	14,92	21,18	33,45	52,61	76,09
80	6,39	11,06	17,43	24,74	39,07	61,45	88,87
90	7,35	12,73	20,06	28,47	44,96	70,71	102,28
100	8,26	14,30	22,54	31,99	50,52	79,45	114,91
**Minimum flow rate							
10	0,30	0,52	0,81	1,15	1,82	2,86	4,14
20	0,58	1,00	1,58	2,25	3,55	5,58	8,07

30	0,88	1,53	2,41	3,42	5,40	8,49	12,28
40	1,19	2,07	3,26	4,62	7,30	11,49	16,61
50	1,50	2,60	4,10	5,81	9,18	14,44	20,89
60	1,86	3,22	5,07	7,20	11,36	17,87	25,85
70	2,19	3,79	5,97	8,47	13,38	21,04	30,43
80	2,55	4,42	6,97	9,90	15,63	24,58	35,55
90	2,94	5,09	8,02	11,39	17,98	28,29	40,91
100	3,30	5,72	9,01	12,80	20,21	31,78	45,97

**Minimum flow rate (thous.m^3/hr), calculated for flow velocity 0,4 m/sec.*
*** Minimum flow rate (thous.m^3/hr), calculated for flow velocity 1,0 m/sec.*

3.2.6. Turbine flowmeters and meters

Tachometer is an instrument that measures the speed of rotation. A turbine meter is a dependable volumetric transducer which provides a direct physical measurement of flow that can be converted into digital pulse digital. All turbine meters include axially-mounted rotors, tangentially mounted «paddle-wheel» and insertion-type probes. It includes a freely suspended rotor blade, generating a frequency output. The frequency is directly proportional to the velocity of fluid, and because the flow passage is fixed, the turbine's rotational speed is a true representation of the volumetric rate flowing through the flow meter.

Flowmeter – a device that measures the amount of fluid moving through a pipe: output signals are proportional to rotation velocity; a meter – a device to measure and often record volumes, quantities, or flow rates of gases, liquids or electric currents, where total runnings of transducer is proportional to the amount of gas (volume or mass).

A turbine flow meter comprises a multi-bladed rotor which runs between bearings and is situated in a flow conduit. The transducer which is located in a wall of the flow conduit senses passage of the blades on the rotor. Fluid passing through the turbine causes it to rotate about its axis. Flow rate totaled for a given time is proportional to flow volume. The rotor has a speed of rotation which is to some extent proportional to the flow rate of fluid passing through the conduit. The rotational velocity is converted into a train of pulses by a transducer.

In turbine propeller flowmeters and meters, the axis is along the flow, in «paddle-wheel» - perpendicular to the flow and in ball-bearing rotor turbine – ball-bearing unit or other body rotates around its axis under the flow impact. Another term is a flowmeter with hydrodynamic bearing rotor. These turbine meters use the mechanical energy of the fluid to rotate a «pinwheel» (rotor) in the flow stream. Blades on the rotor transform energy from the flow stream into rotational energy. The rotor shaft spins on bearings. When the fluid moves faster, the rotor spins proportionally faster. Rotor rotation velocity is proportional to flow velocity, i.e $\boldsymbol{Q}$ – flow rate. A non- magnetic or modulated carrier pickoff can be used to sense the rotation of the turbine rotor. A differential – transform transducer is installed on the housing; there is an annular slot of ferrum-magnetic material in one of the blades. The inductive resistance changes and thus, frequent proportional flow rate $\boldsymbol{Q}$ changes the strain in the secondary winding $\boldsymbol{U}$**.**

Measurement flowmeter device is a frequency meter to measure strain rate frequency. Measurement ranges of such meters are 1: 10, 1:20.

According to sophisticated digital devices and microprocessors, turbine meters are divided into the following classes*:*

- *separate (selective \ component) measurement of operated parameters by choosing arbitrarily processing methods for measurement results (manual calculating devices, microcalculators, etc.);*
- *semi-automatic measurement of operated parameters by computerizing measurement results and manual devices for conditional-constant parameters or manual correction of measurement results and calculations;*
- *automatic measurement for all parameters by computers.*

Advantages. Lightweight package and compact size, cost advantages, design simplicity, ability to withstand high forces, operate across the entire usage range (up to 1:30), in comparison to orifice plates and other traditional flow sensing devices. The turbine meter's speed of response is one of the most significant advantages when compared with other leading meter designs. However, the main advantage is constant transformation coefficient in a wide *Re* flow range. This is based on the fact that these meters are air-calibrated and at zero excess pressure. Accuracy is only in that case if there is an initial constant transformation coefficient, i.e. constant natural output signal ratio to passing air or gas flow. For example, gas for above-mentioned transformation coefficient is determined as the number of rotor rotations, respectively to one unit of passing gas volume (in turbine or rotor meters) [39].

Disadvantages. Sensitivity to flow stress at the flowmeter output and output (requirements to straight run of pipe before and after the device is minimum and is respectively, 1-2dm of given flowmeter passage). Measured fluid pulse flows can degrade accuracy. Turbine flowmeters are less accurate at low flow rates (less than 8…10 m^3/hr) due to rotor \ bearing drag that slows the rotor.

Example:

«TRZ» Meter

Gas turbine flowmeter TRZ (Fig. 3.72) is manufactured at «GasElektronika» (Arzamas, RF), series G2500 (Q_{max} = 4000 m^3/hr) and G4000 (Qmax = 6500 m^3/hr) at working (operating) pressure 1,6 mPascals and 6,3 mPascals.

Fig. 3.72. Meter TRZ: «GasElektronika»(Arzamas, RF)

Measuring sockets (cartridges) in these meters are manufactured by «Elster», while the meters - «GasElektronika» are analogous to the manufactured ones by «Elster» in specifications; at the same time, they are cheaper [40].

Electronic compensators are used for reduction of measured gas volume to standard conditions. For example, compensator EK not only calculates the gas volume at standard conditions, but also determines spontaneous gas flow mean.

Basic performance principles of *TRZ 03-L* (Fig. 3.73). The gas enters the turbine meter through a special designed flow straightener which imposes an evenly distributed pattern on the flow, impinging on the turbine wheel. The contraction of the flow in the annular slot increases gas velocity in order to exert a higher torque on the turbine wheel. The gas flow drives the turbine wheel with a speed proportional to the velocity of the gas. The total volume of the gas passing through the meter per unit of time is equal to the velocity of the gas multiplied by the area of the annular slot, and every revolution of the turbine is equivalent to a certain fixed volume passing through. The turbine wheel in turn drives the counter. The counter is geared to indicate the volume passed through the meter in the appropriate units. Proximity sensors provide electrical outputs. In this way a frequency signal is generated that is proportional to flow rate.

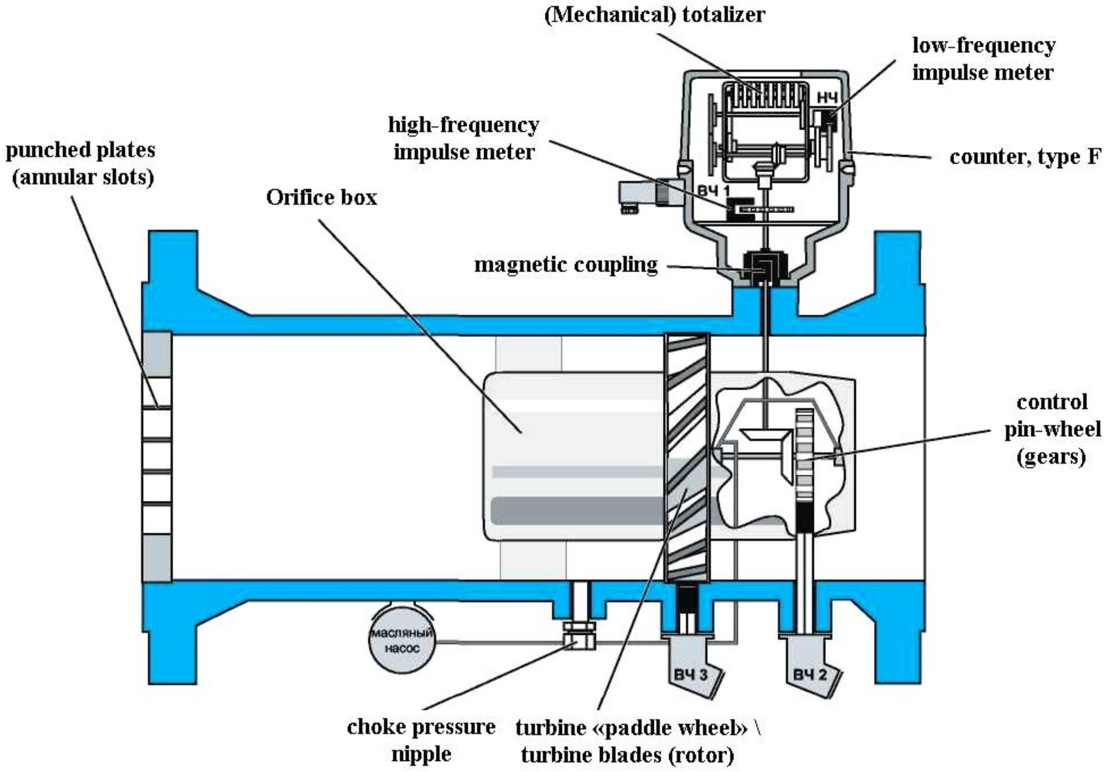


Fig .3.73. Schematic diagram of meter TRZ 03-L

Turbine flow meters are placed in line with the flow. The flow passes first through a **flow straightener** (**flow conditioning plate**) to remove swirl and create a uniform flow. Subsequently, the flow is forced through an **annular channel** and through the **rotor** (flat plates, helical shape). The **shaft and bearings** are placed inside the sealed housing, which is usually suspended downstream of the rotor. The rotor speed is measured by transferring the rotor speed through the rotor axis and via **gears** to a **mechanical counter**.

Specifications: *The meter includes two main units:*

- *sealed housing;*
- *measurement transducer*

Measurement transducer is installed in a sealed housing. Measurement transducer determines metrological meter performance. Measurement transducers are manufactured by ELSTER (Germany). Midcheck-in interval is 10 years. The measurement transducer can be substituted in-place performance for periodic repair or monitoring. There is a maximum short-term loading in gas flow up to 160% of Q_{max}. High-frequency impulse meter A1R and A1S provide measurement of spontaneous gas flow and continuous control of turbine wheel blade integrity.

Main features: (Fig. 3.74…3.78, Table. 3.24): *measured flow mean***:** from 13 m^3/hr to 25 000 m^3/hr. *Measurement error :*< 1% in a range from 0,2Q_{min} to Q_{max}; <2% in a range from Q_{min} to 0,2Q_{max}. *Measurement range*: Q_{min}:Q_{max} = 1:20; (1:30 special specification). *Maximum working temperature*: 1,6 mPascals or 6,3 mPascals (depending on design). *Temperature range:*ambient - from -20 to +70 °C; measured fluid - from -20 to +60 °C. *Midcheck-in interval*: 10 years. *Перепад Differential pressure in the meter at max. flow*: not more than 600 Pascals (60 mm).

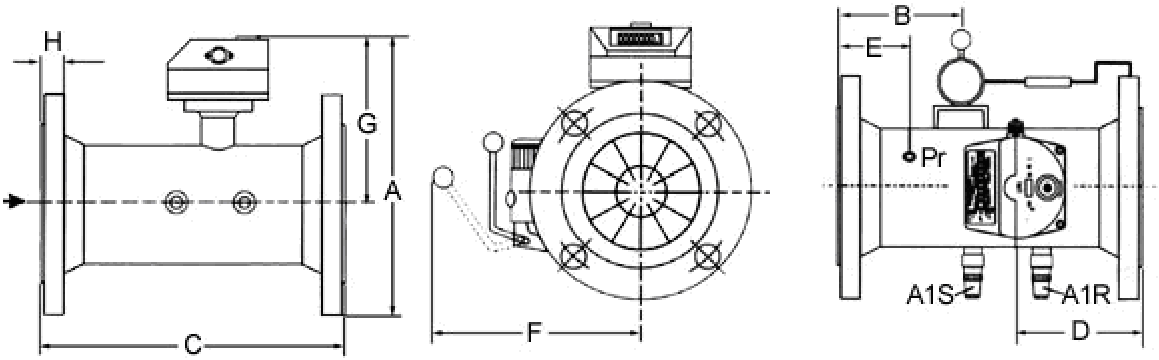


Fig. 3.74.Geometric sizes (dimensions) of TRZ meter

Fig . 3.75.Measurement transducer of gas turbine TRZ meter

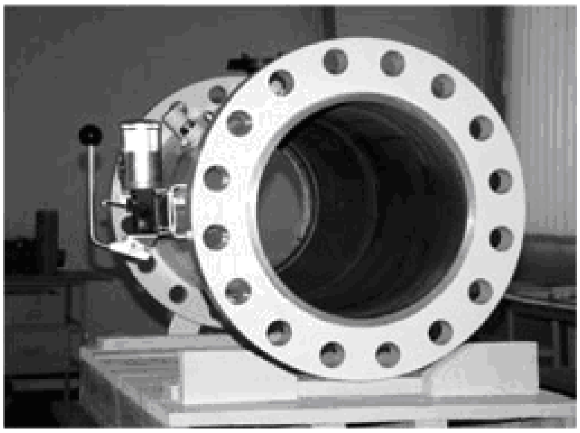


Fig. 3.76. Housing of gas turbine TRZ meter

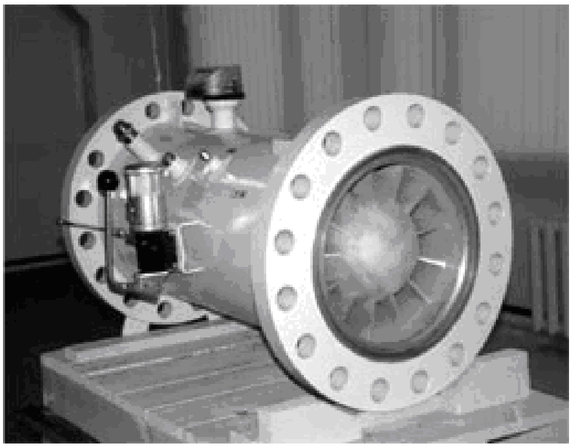


Fig. 3.77. Substituting measurement transducer

Fig.3.78. Gas turbine TRZ meter

Reciprocal collar with a socket is used to install TRZ meter on the pipeline. The straight run of pipeline length: 5Dy to meter and 3Dy after the meter (Fig. 3.79).

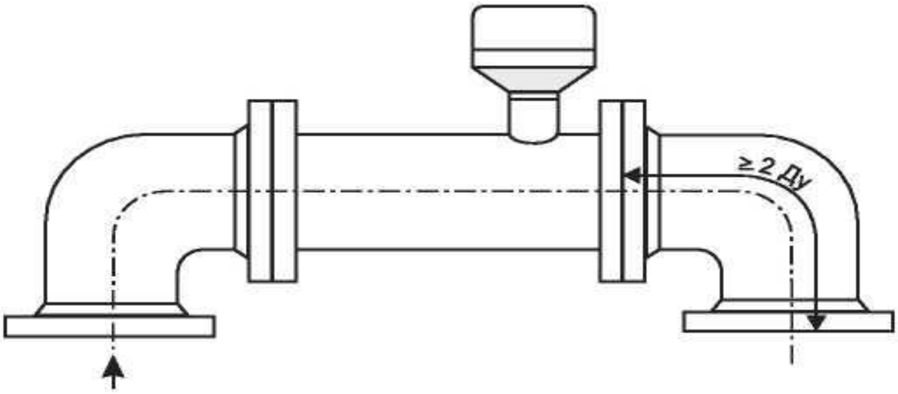


Fig. 3.79. Schematic illustration of TRZ 03-L installation on the pipe

Turbine gas meters TRZ up to Dy 200 operate in any working position; from D_y 250 only in horizontal position. Filling the pipe or other units through the turbine gas meter is prohibited. This results in high flow velocity, and further damage of the flowmeter.. Meter loading is 1,2 Q_{max}. There should be no pulsation or drag in the flow, no solid particles, extraneous dust or liquids. Otherwise, it is recommended to install a filter or separator.

SG meter

Gas meter SG (Fig. 3.80) measures continuously changing flow volume of clean non-aggressive one- or multi-component gases (natural gas, air, nitrogen, argon with density at standard conditions not more than 0,67 kg/m^3) . Applications for gas meters are found in industries and public and commercial services. These meters can not be used for oxygen.

The following meters are manufactured SG-16M, SG-75M-1 and adapted to electronic counter unit EK/88 («ELSTER»).

The following units are used in gas meter installation: 09G2S-Sv-4 steel flanges (***GOST 19281-89***), SG16(M) steel flanges (***GOST 12820-80***), SG75(M)-1 steel flanges (***GOST 12821-80***). To seal flange connections: SG16(M) - paronite PMB spacer from (**GOST** 481-80),SG75(M)-1 – aluminium spacer (***GOST 21631-76***); 35X steel pins(***GOST 10494-80***); 35X steel screws (***GOST 10495-80***) are used.

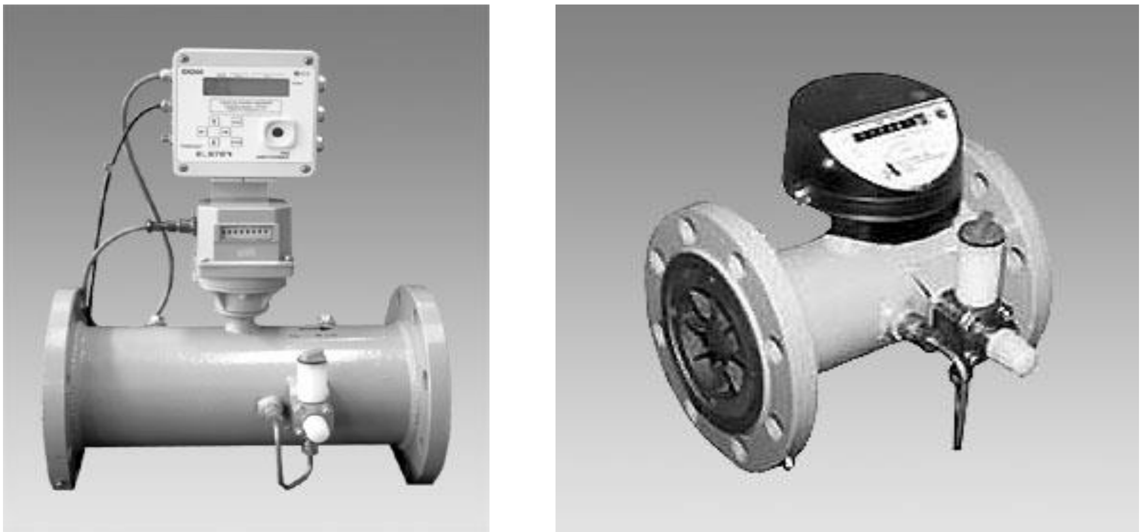


Fig. 3.80. SG gas meter

Technical Specification: measured gas temperature, °C: -20 ... +50; ambient temperature, °C: -30 ... +50 (- 40 ... +50); working pressure, mPascals 1,2 (SG16) and 6,3 (SG75); allowable pressure, mPascals, not more than 1,6 (SG16) and - 7,5 (SG75); differential pressure, not more than Pascals (mm): 800 (80); relative meter error in the flow range from 20 to 100% Q_{max}: ±1%, in flow range from 10 to 20% Q_{max}: ±2%, in flow range 5 to 10% Q_{max}: ±4%; straight pipe run length: not more than 5 Dy before the meter and not more than 3 Dy after the meter, sensitivity threshold not more than 0,033 Q_{max} SG16(M)100 and not more than 0,02 Q_{max} for the remaining ones.

Таблица 3.24

Габаритные и присоединительные размеры счетчиков СГ16М

Meter class	Sizes (Dimensions), mm							
	Dy	D	D_1	D_2	d/n	L	H	B
SG16M-160 SG16M-200 SG16M-250	80	195	160	133	18/8	240	320	245
SG16M-400	100	215	180	158	18/8	300	330	265
SG16M-650 SG16M-800 SG16M-1000	150	280	240	212	22/8	450	400	325
SG16M-1600	200	335	295	268	22/12	450	420	395

The following requirements PR50.2.019 is necessary in the meter installation: minimum pipe section distance before and after the meter (Fig. 3.81); straight run of pipe diameter equals Dy ±2%; a conical filter (*Dy 50 … Dy 200*) to protect gas meter during precommissioning; installation in vertical pipe sections for downstream flow (additional mounting units).

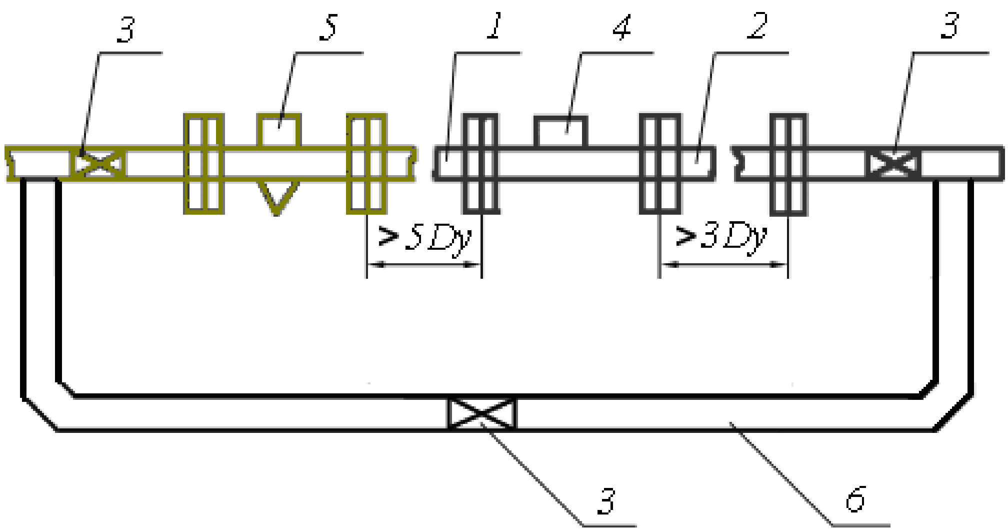


Fig. 3.81. Schematic illustration of gas meter СГ: 1, 2 – nipples; 3 - valve; 4 – meter СГ; 5 - filter (according to GOST 5542); 6 – hypass (non obligatory, only in certain technical processes)

Table 3.25

Technical specification for different SG meter models

Model	Dy, mm	Flow rate at pressure 0,005 mPas, m3/hr.		Max. flow rate at excess pressure to standard conditions, m3/hr		Dimensions \ sizes, mm	Connection sizes, mm	Mass, kg.
		Max.	Min.	0,4 mPas.	1,6 mPas.			
SG16(M)-100	50	100	10	500	1700	150×275×223	No flanges	11
SG16(M)-200	80	200	10	1000	3400	243×320×245	External Ø195	15
SG16(M)-250		250	12,5	1250	4250		8 openings Ø18	
							midcentral Ø160	15
SG75M-200-1		200	10	1000	3400	243×320×245	No flanges	17
	100	400	20	2000	6800	303×330×265	External Ø215 midcentral Ø180 8 openings Ø18	20
SG16(M)-400						303×330×265	No flanges	20
SG16(M)-650	150	650	32,5	3250	11050	453×400×325	External Ø280 midcentral Ø240 12 openings Ø22	35
SG16(M)-800		800	40	4000	13600			35
SG16(M)-1000		1000	50	5 000	17000			35
SG75(M)-1000-1 SG75(M)-800-1		800	40	4000	13600	453×400×325	No flanges	45
		1000	50	5000	17000			45
SG16(M)-1600	200	1600	80	8000	27200	450×420×395	External Ø335 midcentral Ø295 12 openings Ø22	46
SG75(M)-1600-1						450×420×395	–	–
SG16(M)-2500	200	2500	125	12500	42500	450×454×510	–	–
						450×454×510	–	–

3.2.7. Description of flowmeters and meters (advantages and disadvantages)

Table 3.26 ***Description of flowmeters and meters***

3.2.8. Flowmeter technology systems (in determining gas flow)

Basic principles: The main requirements in oil and gas flow measurement are based on the application of hydrocarbon quantity and quality measurement and calculation results for mutual agreement between consumer and supplier (consigner and consignee). Gas parameter measurement and flow calculations, according to the document «Major requirements in automation of gas distribution stations », 2001, should be fulfilled for each separate consumer, which in its turn, requires corresponding number of measurement units.

Gas flow is measured by different methods depending on the applied measuring systems. Methods and the devices (units) to measure gas flow is part of the technical specification in designing FTS (flowmeter technology systems). Gas flow measurement methods function in an independent regime and provide information transmission to automatic FTS control and further. FTS provide data transmission to computers and automatic parameter intake of gas quality from the computer:

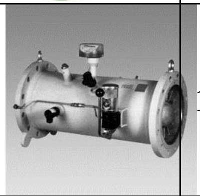
- *$C0_2$ content;*
- *N_2 content;*
- *gas density ;*
- *lower gas heating value.*

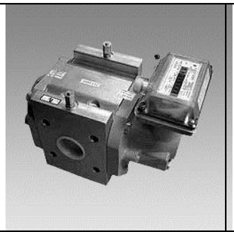
FTS provides manual input of major parameters to computer or VDU, such as:

- *gas density under standard conditions;*
- *nitrogen content in gas;*
- *carbon-dioxide gas content;*
- *barometric pressure.*

Table 3.26

Description of flowmeters and meters

Meter	Type	Ppmax, mPascals	Efficiency, Q, thous. m3/hr		Dy, mm	Measurement erroe, %	Application	
			min, при P=0,4 МПа	max, при P=0,98 МПа			Advantages	Disadvantages
1	2	3	4	5	6	7	8	9
Daniel SeniorSonic		10,0	2,85*	113,78	400	0,5% of standard without flow calibration	high accuracy measurement at constant gas flow velocity; wide measurement range, computer unit	high cost, no diagnostic test *
TRZ G6500		1,6	0,150	6,350	400	< 1 % in the range $0{,}2Q_{min}$ to Q_{max}.; < 2 % in the range Q_{min} to $0{,}2Q_{max}$	high accuracy measurement at constant gas flow velocity	high cost, no diagnostic tests upper range does not correspond to requirements
СГ16(М)-1600		1,6	0,400	17,280	200	-in the range from 20 to 100% Qmax:±1% -in the range from 10 to 20% Qmax:±2% -in the range from 5 to 10% Qmax:±4%	high accuracy measurement at constant gas flow velocity	no diagnostic tests

RVG G250		1,6	0,1	4,320	100	from 0,1Q to Q: ± 1 %	high accuracy measurement at constant gas flow velocity	high cost, no diagnostic tests, upper range does not correspond to requirements
УСБ 400-10,0		7,5	calculation	160,0	400	1…1,5 %	diaphragm is used (simple design, corresponding range), simple substituting procedure (not more than 20 min.)	limitation in measurement range, jamming up of mechanism and further damage
БСУ 400/7,5		7,5	calculation	160,0	400	1…1,5 %	orifice is a diaphragm (together with calibration units); simple substituting procedure	limitation in measurement range, due to inexperience

*Regions: Tomsk, Kemerovo, Novosibirsk, Omsk, Altay

FTS includes database maintenance, archived files and storage, containing measurement and calculated data for 35 days.

Flowmeter technology systems to determine natural gas flowrate and quantity are widely used in Russia and abroad. These systems provide automatic reduction of gas flow to normal conditions, integration to time for determining passing volume in gas pipeline, transformation of received information into signals for automatic control system through remote control [31].

FTS is a versatile system of different measurement units and devices, which include the following characteristics: total of measuring, connecting and calculating components. FST comprises a single measurement unit:

- *receiving information about the object;*
- *automatic processing of measurement results;*
- *registration and indication of measurement results and their processing;*
- *data transformation.*

Flowmeter technology systems (FST) for gas flow measurement include:

- *primary transducer;*
- *units for measuring differential pressure, absolute static pressure, temperature and fluid composition;*
- *planimeters (manual) or electronic planimeters or scanners (automatic)in determining average measured parameter values;*
- *micro-controllers \ computers for automatic flow and quantity calculations;*
- *additional units installed in the pipeline (filters, resistivity indicators, convergent tubes and diffusers, mud traps and others);*
- *additional units installed in the measurement channel (impulse pipelines, valves, condensation, pressure-control, segregating and settling vessels, diaphragm segregators and others).*

Measurement system with an orifice **–** variable differential pressure flowmeter with an orifice.

Измерительный комплекс со счетчиком газа – синоним расходомера на основе счетчика газа, независимо от его типа.

Принципиальная схема измерительного комплекса с сужающим устройством, для учета природного газа, представлена на рис. 3.82.

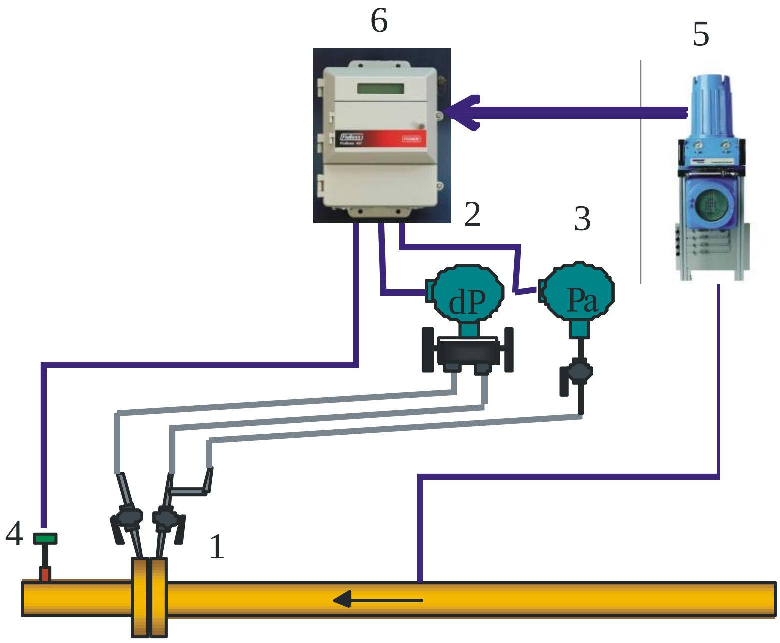


Fig. 3.83. Schematic illustration of measurement system with orifice: 1) primary measurement transducer orifice (diaphragm); 2) differential pressure meter on the orifice; 3) absolute pressure meter; 4) temperature meter; 5) gas chromatograph (streaming); 6) compensator (flow calculator)

The primary measurement transducer includes total section up to the orifice, 100D, the orifice, and section from the orifice, 10D where «flow→differential pressure» transition occurs (where D internal measured pipeline diameter).

Flow meter (turbine, rotor, vortex-acoustic, ultrasonic type etc.) can be primary measurement transducer in the above-mentioned schematic illustration (Fig. 3.83).

The technical unit system in the pipeline provides automatic continuous flow measurement and transporting natural gas volume (quantity) by two independent operating and measuring systems- main and doubling (back-up).

Flowmeters (meters) of orifices are applied in flow measurement and natural gas volume (quantity). The following methods are used in determining transporting natural gas flow and volume (quantity): ***variable differential pressure method in standard orifices,*** according to ***GOST 8.586.1-5-2005*** and ***turbine meters or rotor meters*** according to [PR 50.2.019-96], where FTS provides automatic, continuous measurement of the following parameters (Tables 3.28, 3.29).

Measurement system with gas meter – gas flowmeter

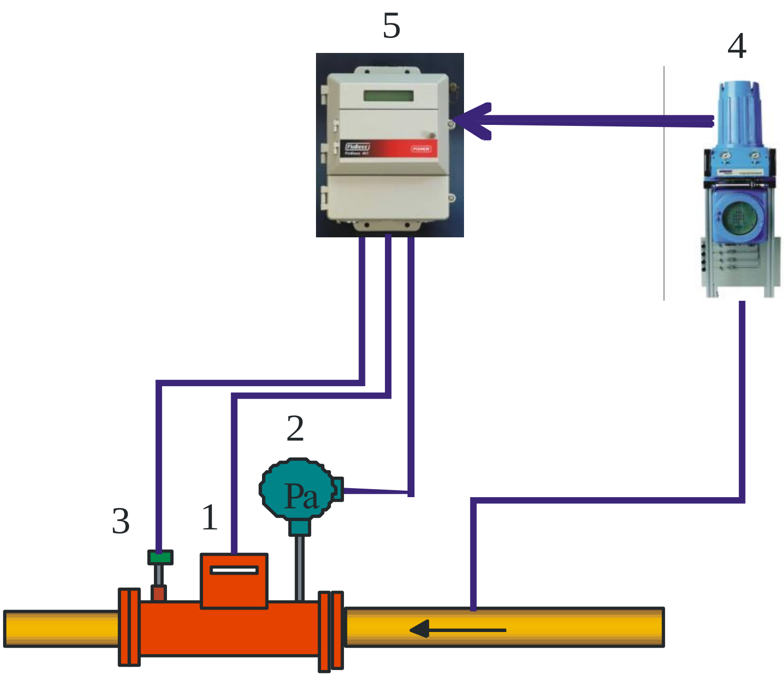


Fig. 3.83. Schematic illustration of measurement system with gas meter: 1) meter (turbine, rotor, ultrasonic, etc); 2) absolute pressure meter; 3) temperature meter; 4) gas chromatograph (streaming); 5) compensator (flow calculator)

Normal conditions for FTS [20] are:

- *ambient temperature - 20 ± 5°C;*
- *relative ambient air moisture - from 30 to 80%;*
- *atmosphere pressure - from 84 to 107 кPascals;*
- *no magnetic field (besides Earth) or within those limits that do not affect the system operation;*
- *differential pressure in diaphragm, ranging from 9 to 100% to upper measurement range;*
- *pressure in the pipeline ranging from 20 to 100% to upper measurement range;*
- *gas temperature ranging from -20 to + 50°C.*

Table 3.27

Characteristic natural gas flow parameters in FST with an orifice

Measured parameters	Units	Features
Pressure in pipeline	One meter: measurement range from 0 to 10 mPascals	Measurement error (including hysteresis and nonlinearity) not more than + 0,1%; non-stable statistic index for one year not more than 0,1%
Gas flow temperature	One meter: measurement range from -20 to +60°C	Absolute measurement error , not more than± 0,3°C
Orifice		
Differential pressure in diaphragm	Two meters of differential pressure: • *meter- measurement range from 0 to 6,3 кPascals;* • *meter- measurement range from 0 to 63кPascals.*	Measurement error, not more than ± 0,1%; additional relative meter reading alteration error affected by static pressure alteration of 5 mPascals- not more than ± 0,2%; non-stable statistic index for one year not more than 0,1%;excess static pressure impact, up to 10 mPascals.

When main relative measurement flow error and natural gas volume is calculated by variable differential pressure method to standard orifices according to GOST 8.563.1-3-97, the main or doubling (back-up) FST in each measured pipeline under normal conditions is not more than + 0,5.

Table 3.28

Characteristic natural gas flow parameters in FST
with turbine or rotor meters

Измеряемые параметры	Оборудование	Характеристика
Pressure in pipeline	One meter: measurement range from 0 to 10 mPascals	Measurement error (including hysteresis and nonlinearity) not more than + 0,1%; non-stable statistic index for one year not more than 0,1%.
Gas flow temperature	One meter: measurement range from -20 to +60°C	Absolute measurement error , not more than± 0,3°C

Turbine or rotor meters		
Impulses	meters	Frequency range from 0 to 5000 Hz; Signal level in open tank, TTL; "dry" contact.

When additional measurement flow error and natural gas volume is calculated by FST, evoked ambient air temperature alteration (20+5)° within operating area is not more than 0,5 relative to error for every 10°C.

Task and Discussion Questions

1. What are the quality characteristics of orifices?
2. Explain gas flow rate measurement by quick-change orifice (QCO).
3. What is the impact of density, temperature and viscosity of transported fluid on its flow rate?
4. Give the examples of differential gauge installations in the pipeline.
5. Provide the main methods to decrease local resistance unit impact on gas flow rate measurement.
6. What is the application of orifice box and flow conditioners?
7. What is the operation mode of volumetric turbine and vortex flow meters?
8. Provide the classification of ultrasonic flow meters, defining their advantages and disadvantages.

4. OIL AND GAS QUANTITY MEASUREMENT IN CRUDE TRUNKLINES

Oil and gas flow control performed in distribution, compressor and measuring stations as well as in tank farms and in underground storing systems is one of the main measurable parameters which determines many industrial, economic and performance characteristics of trunk pipeline system units. [31, 32, 41, 42].

Oil and gas flow control is applied for:

- *further supplier-consumer financial settlement;*
- *oil and gas gathering and delivering balancing;*
- *pipeline operation mode and operation condition monitoring;*
- *gas system flow rate and hydrolic regime monitoring, as well as, gas conservation and efficient use.*

Due to high responsibility assumed by the Supplier for oil and gas transportation from the oilfield to the pipeline terminal (Consumer) and with a view to cost reduction and maximum profit earning, oil and gas flow control technology, as well as, its quality should be seriously regarded. ***Thus, accurate oil and gas flow measurement is important for the whole system of product registration and supply scheduling.***

To choose an appropriate gage the following rules should be considered.

- *operation conditions should be controlled by indicating gauges;*
- *parameters which changes can lead to equipment accident conditions should be controlled by recording gages;*
- *parameters which are important for equipment performance analysis and economic accounting should be controlled by recording and integrating gauges.*

4.1. Tank Gas Flow Control Unit

Flow control unit *– is a set of measuring gauges and devices intended for gas flow control including its parameter reading*.

Flow control units are constituents of the manufacturing equipment applied in the gas-distributing, gas-measuring and compressor stations.

4.1.1. Flow Control Unit Installation Design

There are two installation designs. Flow control unit can be installed as a factory-assembled device approved by the manufacturer. At the same time it can be assembled at the immediate place of installation, i.e. commercial flow control unit. The main components of a flow control unit are: primary flow transducer, computer, pressure and temperature sensors and peripheral devices. As a rule, such units are not state certified as a single whole equipment. Pressure and temperature sensors, computer and gas meter have state certificates.

Any installation pattern should meet the following normative document requirements.

- *according to Measurement Assurance Law of Russian Federation commercial flow control unit must be certified and registered in state measuring system;*
- *according to GOST 8.143-75 State Primary Standard and All-Union accuracy chart for volumetric gas discharge measurement ranging from* $1 \cdot 10^{-6}$ *-* $1 \cdot 10^{6}$ m^3/sec*, permissible relative error limits are from 1to 5%., while according to Building Norms and Acts 2.04.08 – 87 «Gas Supply», gas flow control units must meet the requirements regulating total unit relative error not more than 2,5%;*
- *according to the rules "Technical device application in dangerous manufacturing entities" which were approved by Russian Federation of 25.12.98 г. № 1540, it is strictly forbidden to install a flow control unit equipped with electric proofreader in gas facilities of Russian Federation without application permission and licence issued by state municipal engineering supervision of Russia (permission and licence are issued under permissibility certificate).*

Measuring systems manufactured according to the first pattern entirely correspond to the requirements listed in the normative documents. They were tested as a single unit to determine measuring instrument type. During distribution tests each unit is calibrated and its total accuracy is issued:

$$\delta = \pm 1{,}1\left(\delta_c^{\,2} + \delta_{\hat{e}}^{\,2}\right)^{0{,}5}, \tag{4.1}$$

$\boldsymbol{\delta}$ *– basic relative error of measuring system standard volume definition;*

$\boldsymbol{\delta_c}$ *– gas meter relative error (primary measuring trunsducer);*

$\boldsymbol{\delta_к}$ *– computer relative error, including pressure, temperature and compressibility coefficient errors;*

1,1 – coverage coefficient.

Electrical proofreader is also tested before unit installation. Pressure and temperature channel errors, as well as, standard volume coefficient calculation error are defined and certificated for each proofreader. Thus, proofreader and the whole unit accuracy compliance is approved by corresponding certificates with special state standard mark. The copies of all compulsory certificates and safety operation permits issued by Russian engineering supervision are enclosed with flow control unit accompanying documents.

As a rule gas-transport companies possessing high efficient gas-distribution stations and GIS for the individual designs are the followers of the second flow control unit installation pattern. They prefer applying a computer as a unit of different primary flow transducers, pressure and temperature sensors, power supplies and spark protection barriers. In this case each control flow unit set should have the state standard certificates confirming measuring instrument types.

When the unit is installed it should be tested according to the technology approved by the representatives of State Committee for Standardization. Control flow unit should have state standardization committee certificate to certify its requirements compliance issued by Building Norms and Acts 2.04.08 – 87 "Gas Supply"

Basic relative error in determining control flow unit standard volume is derived from the following components:

$$\delta = \delta_c + \delta_{\partial\partial} + \delta_{\partial m} + \delta_{в}, \qquad (4.2)$$

δ_c *– gas meter relative error (including error due to shortening or non-standard length of straight pipeline sections);*

$\delta_{\partial\partial}$ *– pressure gage relative error (absolute);*

$\delta_{\partial m}$ *– temperature gauge relative error;*

$\delta_{в}$ *– computer relative error, including pressure and temperature measurement, as well as, compressibility factor calculation error.*

Due to the application of high-precision primary sensors as primary transducers of a standard orifice plate (a factory-made calibrated device with straight pipe sections before and after it –table 1) high accuracy of such measuring system can be achieved.

Real error can be defined by well-qualified staff and only if high-precision and high automated comparison equipment, as well as, high-precision standard instruments for pressure and temperature monitoring are available.

4.1.2. Gas-distribution and gas-measuring stations

According to ***RRD 39-1.10-005-2000*** and ***RRD 39-1.10-006-2000*** [43,44], gas-distribution station GRS (Fig. 4.1) is constructed in the gas pipeline and is intended for gas supply/transmission to the factories and built-up areas in accordance to the following parameters: volume, pressure, purification efficiency, odorization and volumetric gas discharge and qualitative variables if required.

Gas distribution station are intended for operating in the areas characterized by different climatic and seismic conditions. Based on the maintenance type, gas-distribution stations are divided into 5 groups (Table. 4.1).

Fig. 4.1. Gas-distribution station

Table 4.1

Gas-distribution station

Maintenance	Capacity thous. m^3/h	Characteristics
1	2	3
Centralized	not more than 25.	Planned control and repair work are carried out without maintenance staff once a week.
Periodical	not more than 50	GDS is maintained by an operator according to approved schedule

1	2	3
Outwork	not more than 150	GDS is maintained by two operators according to approved schedule (one operator is a senior one)
Shift work	more than 150 thousand m^3/h with two or more output reservoirs	Around-the-clock service according to approved schedule
Automatic	up to 100	Technological operations are completely automated to make gas reduction and supply pocesses out of running. Such kind of maintenance is approved by Transmission Facility Department

According to GDS nomenclature, listed in ***RRD 39-1.8-022-2001*** [45], GDS classification including the structural arrangements can be represented as the following (fig. 4.2).

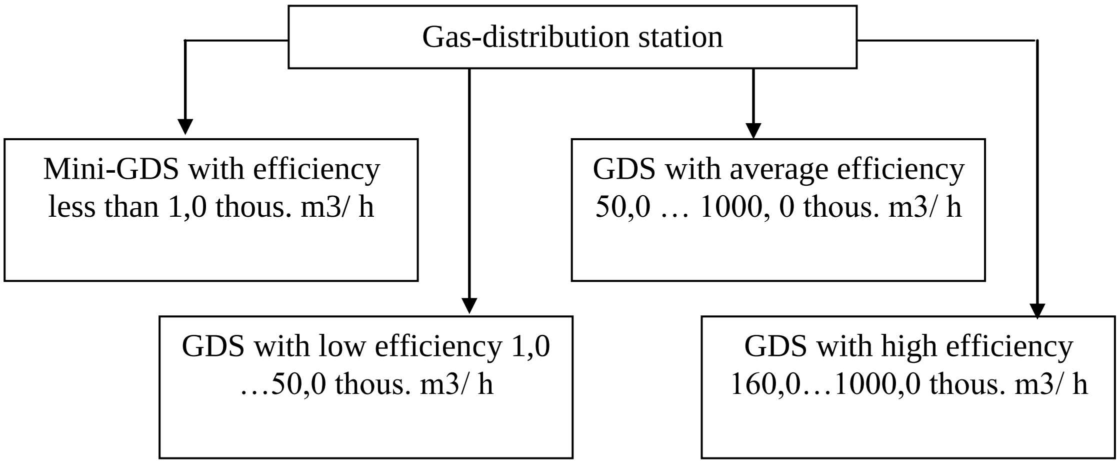


Fig. 4.2. Gas-distribution station classification according to RRD 39-1.8-022-2001

According to ***Construction Standards «Trunk pipelines»*** [46], ***Controlling Documents 39-1.10-005-2000*** [43], ***RRD 39-1.8-022-2001*** [45] the following units and blocks in the GDS are distinguished (Fig. 4.3, 4.4 Table. 4.2).

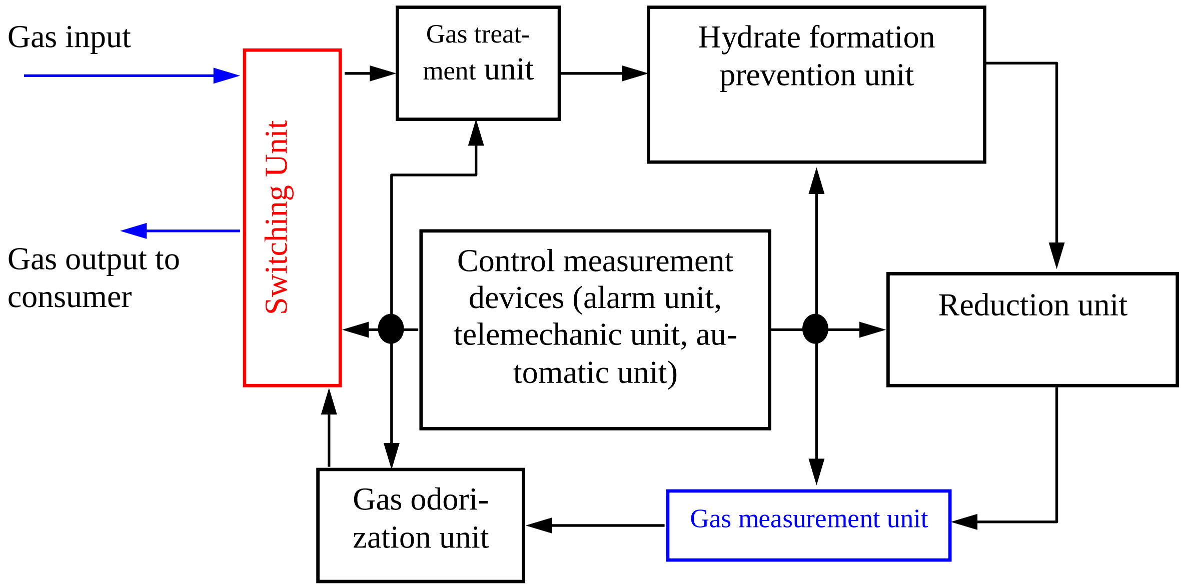


Fig. 4.3. Gas-distribution station structure with one consumer

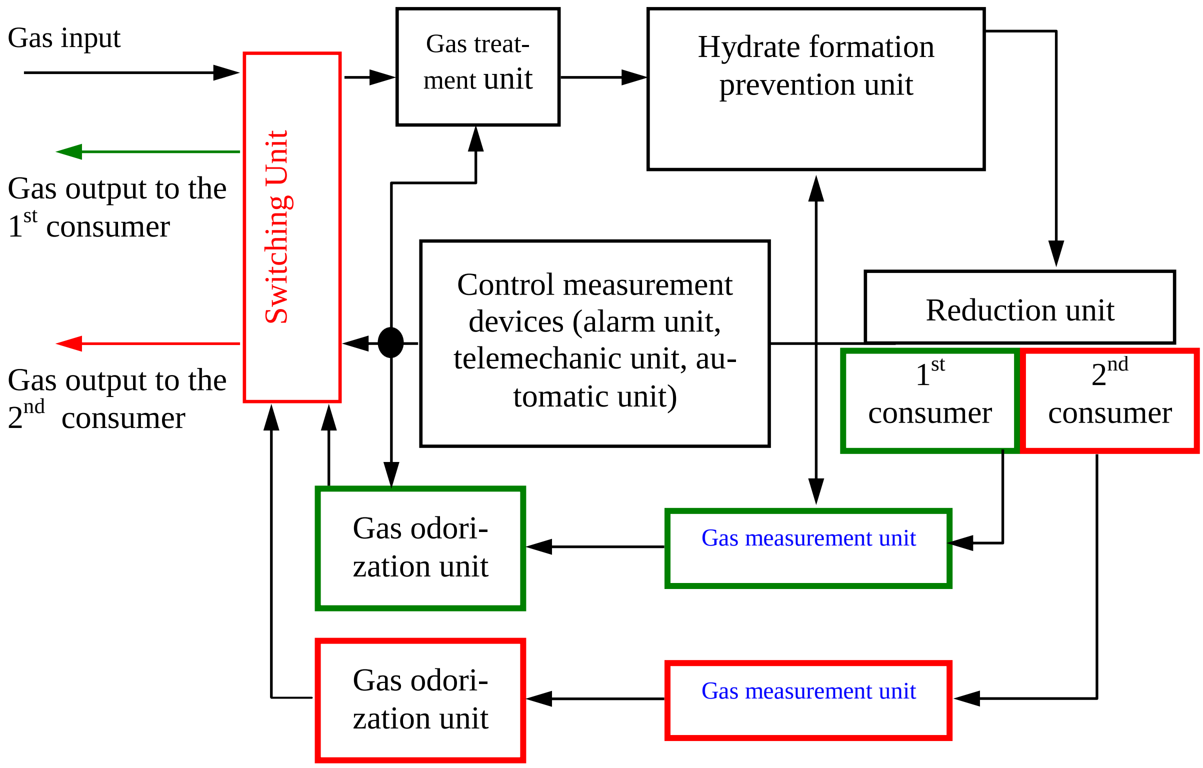


Fig. 4.4.Gas-distribution station structure with two consumers

Таблица 4.2

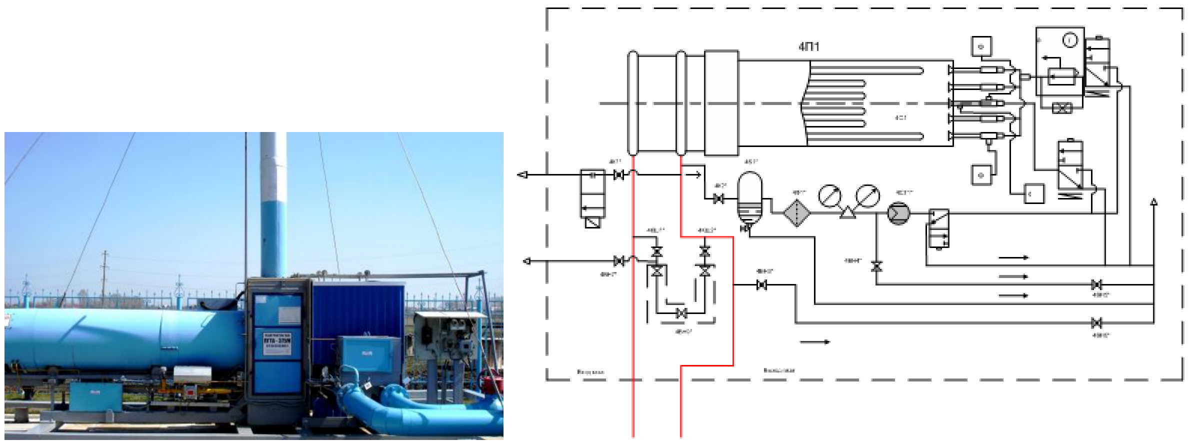
Main gas-distribution station units		
Unit	Characteristics	Functions
1	2	3
Switching unit	Switching high pressurized gas flow from automatic into manual control regime through the loop fitted with local gas pressure and temperature monitoring instruments; intended for short-term gas supply omitting gas-distribution station in a case of emergency and repair work.	• Pressure and temperature measurement in inlet and outlet of a gas-distribution station, reading analysis considering set technological parameters, alarm signaling; • Valve, guard valve position signaling; • Valve and quard valve remote control, automatic stop in case of emergency.
Gas treatment unit	Gas treating from mechanical impurities and condensate and includes: • *Dust and moisture traps used for gas treatment providing stable gas-distribution equipment performance;* • *Devices intended for cuttings removal into gathering units equipped with level gages and mechanized removal system*	• Drop pressure measurement in separator; • Minimum and maximum permissible fluid level signaling in separator; • Valve position signaling in the gas blow-off line; • Distant and automatic valve control in the fluid blow-off line according to liquid level in the filter-separator; • Maximum liquid level warning alarm in gathering units.

1	2	3
Hydrate formation prevention unit	Armature frosting and crystalline hydrate formation prevention in gas pipeline system. The following measures to prevent hydrate formation are applied: • *Total or partial gas heating;* • *Pressure control body heating;* • *Methanol in-feed in the gas pipeline systems*. Gas heating unit, hot-water and steam boilers are operated under the pressure not more than 0,07 MPa depending on the heating unit. Heating unit is operated by its own automatic system.	• Gas pressure and temperature measurement in the outlet of the heating unit; • Valve position signaling in the inlet and outlet of the heating unit, as well as valve position signaling in the feed loop line; • Valve automatic and remote control; • Alarm signaling
Reduction unit	Gas pressure reduction and its maintance at a set value. Reduction unit consists of not less than two reduction lines (main and reserve lines). Gas low flow line can be implemented at the start-up operation period of the reduction unit.	• Valve position control in reduction lines; • Automatic and remote switching on/ switching off of reduction lines including reserve and subsidiary ones; • Gas pressure signaling in the reduction lines between sequentially installed controllers; • Gas automatic regulation

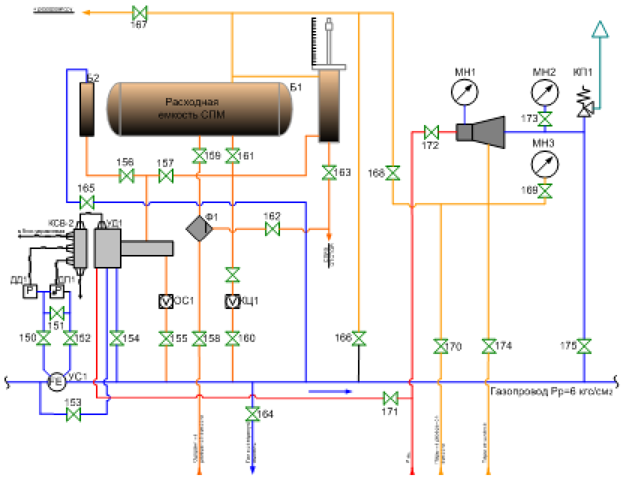
1	2	3
Gas measurement unit	Commercial gas accounting and it includes temperature, pressure and gas flow measuring systems	• General parameter measurement and necessary constant introduction; • Gas pressure measurement; • Gas temperature measurement; • Gas flow measurement (by variable pressure drop technique or by impulse output gas meter application); • Gas flow analysis.
Gas odorization unit	Gas odorization before its transportation to the consumer to find timely possible gas leak. Gas odorization is automatically monitored. The unit should include odorant storage tanks, meter devices at the place of odorant input and control device for defining the quantity of odorant input depending on the gas flow.	• Minimum level alarm in the odorant storage tank; • Meter odorant input; • Odorant flow signal; • Input odorant amount control
Control unit and A unit of control measurement devices and A and stop valve	Transported gas parameter measurement and monitoring, as well as, for efficient technological process control. Stop valve is intended for trunk pipeline, mechanism and tank shut-down.	• Temperature measurement in the control unit; • Alarm signal of explosive natural gas concentration in technological and control unit.

a)

b)



c)



d)

Fig. 4.5. GDS units a) gas reduction unit; b) treatment and switching units; c) hydrate formation prevention unit; d) odorization unit

Gas measurement unit can be installed in the inlet and outlet of a gas-distribution station depending on the measured parameter changing range, GDS operation regime and cost efficiency. When the unit is located in the outlet of the gas-distribution station, gas is measured in each output pipe. When there are low gas flow pipes, measuring unit should be provided with measuring pipe low flow.

Measuring unit should indicate:

- *operation time;*
- *gas flow in working and standard conditions;*
- *hourly and daily average gas temperature;*
- *hourly and daily average gas pressure.*

Gas is measured in both supplier and consumer units according to the measurement techniques established in a definite order. Gas should be measured under normal conditions. Based on the agreement between a supplier and a consumer, gas can be measured by the devices with regard to temperature or temperature and pressure. Measuring unit should provide measurement data printing. Measuring unit range should correspond to the gas flow range where the minimum flow range limit is defined with regard to ultimate permissible flow measurement error.

Measuring unit readings are applied in calculations carried out both by supplier and consumer. Measuring gas unit should always be installed as a separate system including flow measurement devices. Measurement unit range should be from zero up to potential output. When gas measuring unit is operating, all control-measurement devices should have been tested by the State Standard Committee. Gas flow measuring devices should be calibrated not rarely than once in three months, including test record sheet.

Gas flow data should be transmitted to the gas-distribution station automatic control system for further application in gas ordonization, gas flow rate regulation in the outlet from the GDS, and data transmission trunk o the pipeline dispatch control.

In a case of rough gas consuming measurement should be conducted when gas flow is not lower than 30% (with orifice flow meter application) and 20% (with turbine and rotary meters application), as well as when gas flow is higher than 95%.

Orifice plates and other devices should be installed after gas treating unit, before or after gas reduction unit. Control-measuring and telecontrol devices should be installed in heated space or units where the ambient temperature is lower than 5 °C.

If necessary, additional measuring instruments can be applied during the start-up period of the gas-distribution station when gas flow is 30%.

Working gas flow measurement 30-95 and 20-95% range should be provided by connecting an appropriate device to the orifice plate and switching over the measuring unit lines manually or automatically.

Gas-measuring station included the trunk pipeline production facilities and provide gas transportation to the consumers. Gas-measuring station is mantled in the linear pipeline section (loop) as far as possible from the compressor stations in order to decrease the effect of pulsation and disturbance caused by compressor station operation.

To meet the requirements of the profit-and-loss gas flow account in the gas-measuring station, the following natural gas quantative parameters should be measured:

- *gas composition;*
- *dew-point temperature for water;*
- *dew-point temperature for hydrocarbons;*
- *hydrogen sulphide content, sour sulfur and total sulfur*.

Based on the function and equipping level, gas-measuring stations are divided into [45-47]:

- *I - GMS at the Russian borders;*
- *II – GMS as a unit of GDS, transporting gas to the consumer in great amounts;*
- *III - GMS at the borders of "Gasprom"*.

When control-measuring system intended for commercial gas flow account is applied, the following rules for I and II GMS categories are regarded:

- *automatic gathering, processing, registration and storage of the qualitative and quantitative gas characteristics by main and redundant instrument set;*
- *automatic gas flow calculation and reading registration*.

Depending on the supply conditions, gas qualitative characteristics in the GMS of the third type can be defined in laboratory.

Gas quantitative and qualitative characteristics should be defined according to GOST ***8.586.1-5-2005*** and metrological regulations ***MR 50.2.019-96*** "Measurement procedure by turbine and rotary meters", as well as to other methodic and technological normative documents issued by State Standard Committee and “Gasprom”.

Natural gas quantitative and qualitative characteristic readings are applied in supplier-consumer calculations.

4.2. Oil Measurement

Oil-production control in Russia is an integral part in the commodity-commercial operation in the following oil industry sectors- transportation, refinery and production. The commodity-commercial operation during oil transportation is depicted in Fig. 4.5. Oil processing and distributing include the following processes: determination of oil quantity and quality, delivery-acceptance documents in compliance with technical-specifications [30, 47].

Commodity-commercial operation is between *consignee and consignor*.

Consignor (Seller) in petroleum - *to deliver (transport) petroleum for custody or sale.*

Consignee (Customer) in petroleum – *the one to whom petroleum is consigned to destination, and delivery-acceptance documents are complied*.

The classification of petroleum according to destination (Fig 4.6).

Delivery- distribution station (DDS) (Fig. 4.7) – *where oil is distributed to customers, to lease operations to other points of consumption, i.e. to control the supply of oil (quantity and quality) from the point of local supply to.* [48].

DDS are can be included in pumping station (PS) («Raskino», Tomsk region), pipeline control station (PCS) («Aleksandrovskaya», Strezhevo, Tomsk region), region oil management- administration (ROMA) (Omsk) and management –administration in crude trunkline (MACT) (Nizhevartovsk, Tumen region.)

Objectives- to provide exact and reliable control of oil quality and management- technical requirements to delivery-distribution operations. The following operations are conducted:

- *daily control of intake, pumped, delivered and in stock oil quantity; all necessary information is communicated to commodity-transport and operation-managing services;*
- *samplings from tanks and pipelines, oil quantity measurement and quality factor (indexes) system, testing and storage of arbitrary samples;*
- *delivery-acceptance documentation, quality certificate, reports for commodity-transport services;*
- *control of transported oil according to technological specifications;*
- *control of transported oil parameters;*
- *control of measurement unit and equipment operations according to technical specifications;*
- *control of measurement system metrological characteristics in the mid-check interval during pipeline performance;*

control of necessary alterations in metrological characteristics.

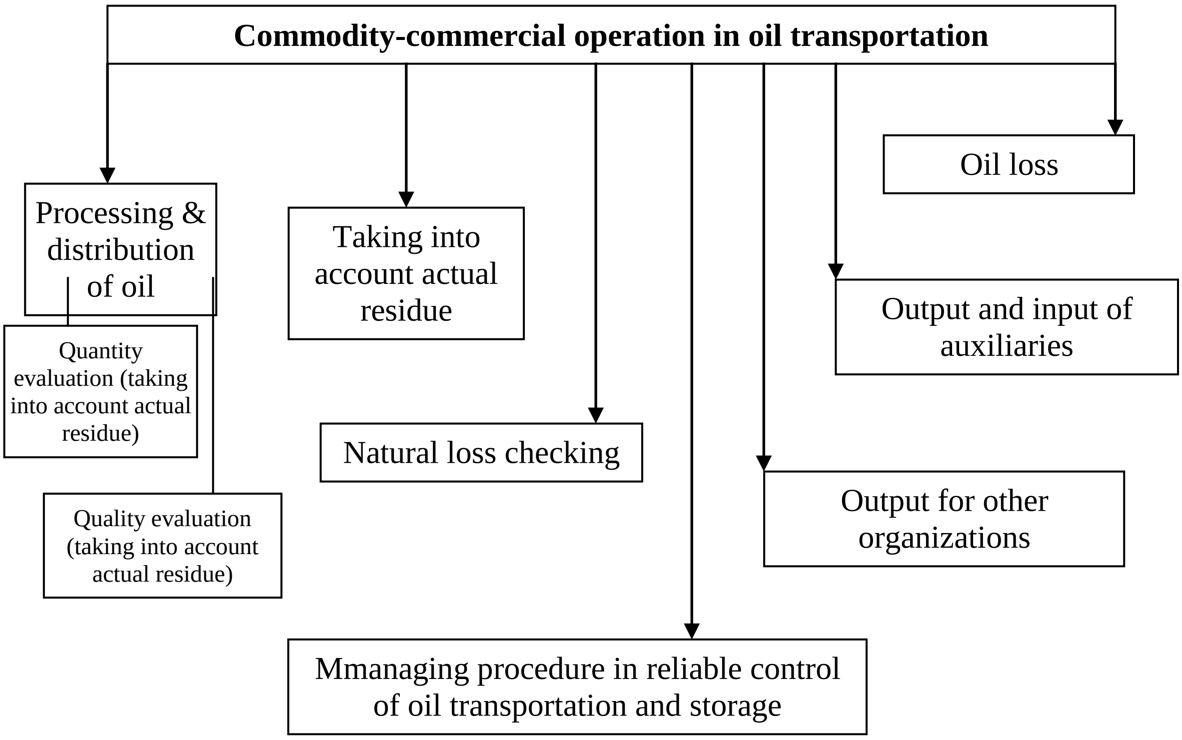


Fig. 4.6. Commodity-commercial operation in oil pipeline transportation JSC «AK «Transneft»

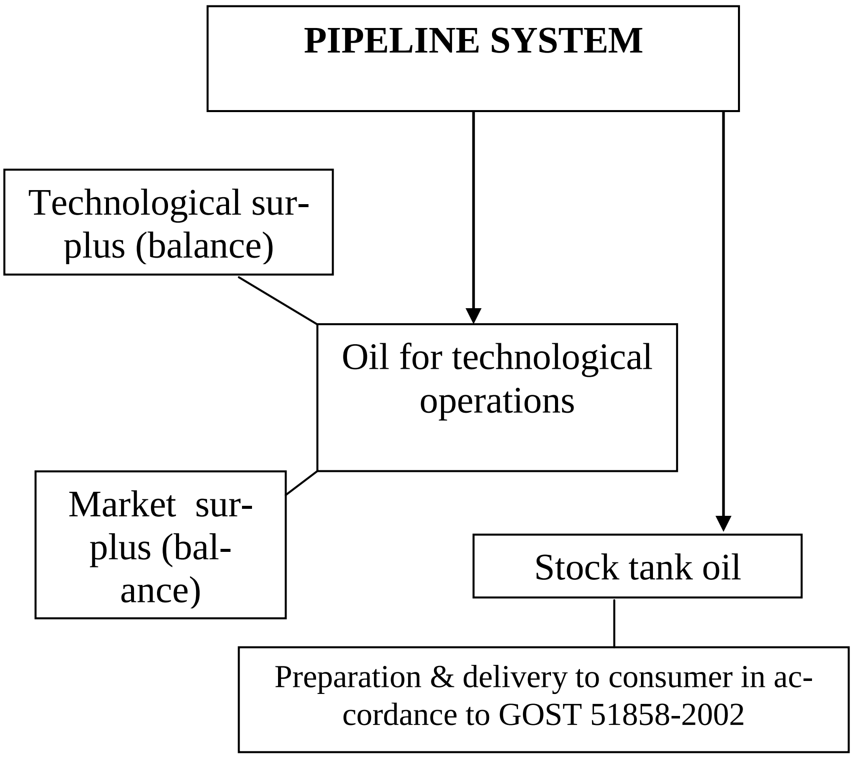


Fig. 4.7. Oil classification to its function

Control scheme is an oil quantity measurement and quality factor (indexes) system.

Oil quantity measurement system (OQMS) [48] includes measurement methods, data processing systems, and technological equipment and pipeline fittings. It is based on the dynamic measurement method for oil gross mass and includes:

- *data information of measured oil parameters;*
- *automatic and manual processing of measurement results;*
- *indexation and registration of measurement results and further processing.*

There can be several oil quantity measurement and quality factor (indexes) systems in the delivery-distribution system. In the DDS there can be only one oil quantity measurement and quality factor (indexes) system which includes several enterprises based on concluded contract. The operation regime of oil quantity measurement and quality factor (indexes) system is constant or periodical.

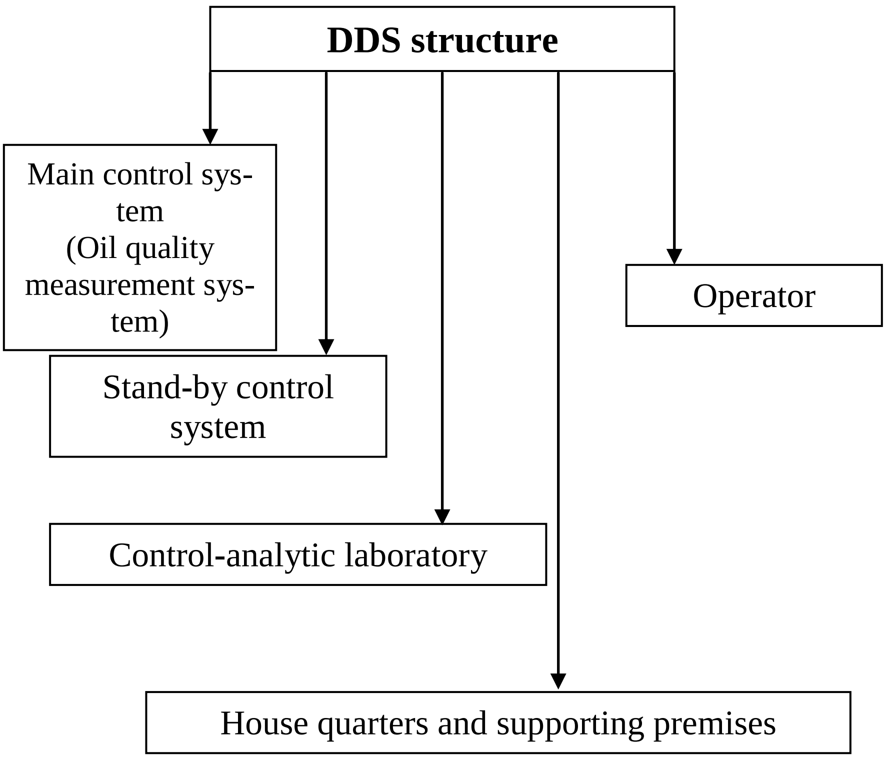


Fig. 4.8. Pipeline delivery-distribution system

Oil quantity measurement and quality factor (indexes) system is divided into commercial and operative in accordance to their functions (Fig.4.9).

Stand-by control system is **oil quantity measurement system, storage capacity (volume) measures** (tanks, ship tanks), **full storage capacity (volume) measures** (railway and trunk tanks).

<u>*Storage tanks in DDS*</u>, used as stand-by control system, include stationary measurement units for oil level and commercial water. Tanks include tank capacity tables (calibration tables). Storage tanks are determined according to ***GOST 8.570***, ***GOST 8.346*** and ***RD 50-156***.

Automatic oil tank control includes:

- *stationary level gauges within absolute allowable error ± 3 mm;*
- *stationary multi-point temperature transducers within absolute allowable error ± 0,5 ºC;*
- *stationary samplers according to **GOST 2517**.*

Stand-by measurement units can be portable measurement level gages, portable temperature transducers within absolute allowable error ± *0,2 °C* or thermometers within absolute allowable error ± *0,2 °C* (temperature is determined in point samples or at given level).

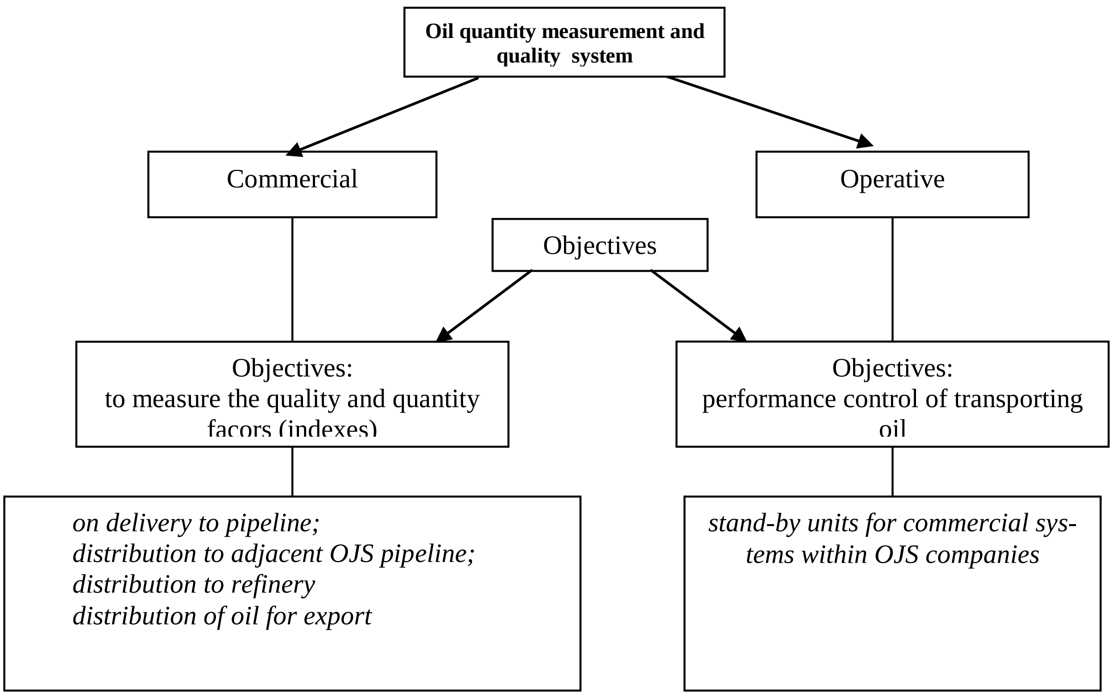


Fig. 4.9. Oil quantity measurement and quality system division to their functions

Oil density in tanks is determined through portable density measurement gages within absolute allowable error ± 0,5 kg/m^3 or in the laboratory according to ***GOST 3900***, **GOST *P 51069*** and ***MI 2153*** in combined samples to ***GOST 2517***. Density determination through line density transducers and automatic sampling in accordance to ***GOST 2517*** is carried out during tank pumping –in and pumping-out.

Storage tank control is carried out through measurement systems to determine oil quality in the tanks:

- *oil level measurement channel through level gauges within absolute allowable error ± 3 mm;*
- *commercial water level measurement channel through level gauges within absolute allowable error ± 10 mm;*
- *density measurement channel through point density transducers within absolute allowable error ± 0,5 kg/m^3;*
- *oil temperature measurement channel through temperature transducers within absolute allowable error ± 0,5 °C;*
- *data processing unit within relative error in determining oil mass ±0,1%.*

Storage capacity (volume) measurement in <u>railway and trunk tanks</u> is determined through the results of:

- *weight measurement ;*
- *measurement at loading station through tanks;*
- *measurement in railway and trunk tanks*.

Railway and trunk tanks are used to measure oil mass as full storage capacity (volume) measurements, which are determined in accordance to ***MP (measurement procedure) 2543*** (railway tanks) and ***GOST P 8.569*** (trunk tanks).

Oil density in tanks is determined through portable density measurement units within absolute allowable error ± 0,5 kg/m^3 or in the laboratory in accordance to ***GOST 3900***, **GOST *P 51069*** and ***MP 2153*** in combined samples, selected to ***GOST 2517***.

Temperature is determined through portable temperature transducers within absolute error ± *0,2 °C* or thermometers within absolute error ± *0,2 °C* in point samples.

<u>River and marine storage tanks</u> are used to measure oil mass and is determined according to:

- *shore tank capacity tables (calibration tables);*
- *measurement results in ship tanks.*

Marine tanks are used to measure oil capacity mass and tank capacity tables (calibration tables). Tank capacity is determined through correction factor, calculated to ***MP 1001***.

Tank oil density is determined in the laboratory in accordance to ***GOST 3900***, ***GOST P 51069*** and ***MP 2153*** in combined samples, selected to ***GOST 2517***. Density determination through in-line densimeters and automatic sampling is carried out in accordance to ***GOST 2517*** during pumping-in.

Temperature in point samples is determined by portable temperature transducers within absolute error ± *0,2°C* or thermometers within absolute error ± *0,2 °C*.

Control-analytical laboratory

The main functions are exact oil testing in accordance to specifications GOST P 51-858-2002, determination of quality physico-chemical oil factors to control the technological regimes and performance of the automatic oil control units.

Research laboratory includes:

- *qualified engineering staff and laboratory assistants;*
- *equipped room in accordance to requirements and regulations;*
- *all equipment for oil sample testing, external conditions control in accordance to metrological and technical specifications;*
- *standard samples, chemical agents and substances for testing in accordance to document requirements;*
- *updating regulations and documents;*
- *registration system for oil sampling;*
- *control system for testing result quality;*
- *oil sampling schedule;*
- *checking schedule for testing units, testing equipment calibration and specification control of supplementary laboratory equipment;*
- *data monitoring system and reports of testing results;*
- *software for processing, registration, documentation and data storage*.

4.2.1. Oil mass measurement method classification

There are *two main methods in measuring oil and oil-product mass* during control-calculation operation:

- *direct measurement method;*
- *indirect measurement method*.

Direct and indirect methods are subdivided into the following classification, depending on place and method (Fig. 4.10).

Direct method of dynamic oil and oil product mass measurement **–** based on direct measurement of oil product mass through weight scale in the pipeline.

Direct method of static oil and oil product mass measurement **–** based on direct measurement of oil product mass through weights and weight dosimeters.

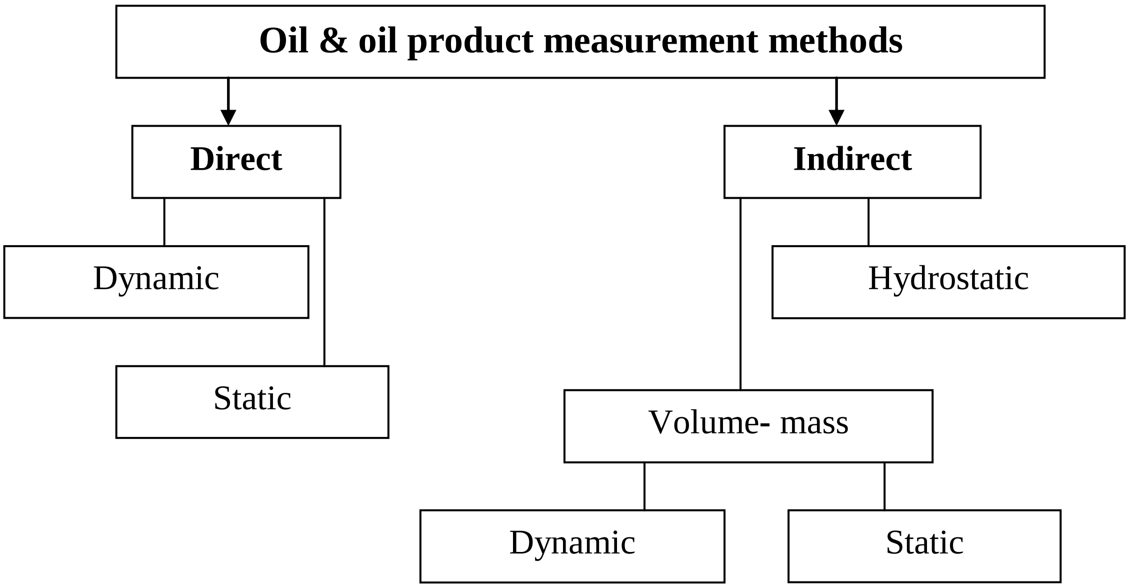


Fig. 4.10. Oil & oil product measurement method classification

Indirect volume-mass method of dynamic oil and oil product mass measurement **–** based on measurement of oil product density and volume in the pipeline.

Indirect volume-mass method of static oil and oil product mass measurement **–** based on density and volume measurement in capacity units (tanks, tankers).

Indirect volume-mass method of oil and oil product mass measurement according to hydrostatic principle **–** based on measurement of hydrostatic pressure and product level in oil capacity unit (Table 4.3).

Table 4.3

Measurement factors and units for different methods in determining oil quantity classification

Oil measurement methods	Measurement site	Measured factors	Units for measurement
1	2	3	4
Direct dynamic	pipeline	mass	weight scale
Indirect dynamic		density	line-in transducers for density, pressure, temperature
Direct static		volume	transducers for flow, pressure, temperature
			fluid meters
Direct static	capacity measures	mass	weights

Indirect static	capacity measures*	level	stationary level gauges
			rod meter
			metal retractable pocket rule (electronic)
		density	portable / stationary density measurement units
			densimeters
		temperature	portable or stationary temperature transducers
			thermometers
		volume	calibration tables for capacity measures
Indirect static	full capacity measures**	density	portable density measurement units
			densimeter
		temperature	portable temperature transducers
			thermometers
		volume	calibration tables for full capacity measures
Hydrostatic	capacity measures	hydrostatic oil pressure	stationary meter for hydrostatic pressure ***
		level	portable or other level measurement units

Примечание:
**** – Capacity measure****: a table that indicates the quantity of liquid contained in a tank at any given level (tanks, railway tanks, tankers).*
***** – Full capacity measure****: units to measure oil volume with control and level indicators (trunk tanks, tank-trailers, tank semi-trailers).*
***** – Hydrostatic method** *– oil mass is the ratio of hydrostatic pressure oil column product value and average area of filled tank part to gravity acceleration:*

$$M = \frac{PF_{cp}}{g}, \tag{4.3}$$

where ***P*** *– hydrostatic oil pressure in tank relative to level indication by measurement device, Pascal;*

F_{cp} – average tank area cross-section, determined by calibration tank table;

g – gravity acceleration.

There are two variants in determining released oil mass in hydrostatic measurement:

- *mass difference is determined at the initial and end of commercial operation (above-mentioned method);*
- *product difference of hydrostatic pressure at initial and end of commercial operation to average tank area cross-section and divided by local gravity.*

Hydrostatic pressure oil column measurement is carried out through manometer devices including saturated oil vapor pressure [31].

Net volume – total volume of liquid in a tank after adjustments have been included for S&W content, temperature and density. Net volume is in ***tonnes***.

Oil net volume – difference between oil gross mass and balance mass*:*

$$\text{Ì}_{\text{í}} = \text{Ì}_{\text{á.ð}} - \text{Ì}_{\text{á}}. \tag{4.4}$$

Mass ballast – total mass of water, hydrochloric salts and mechanical impurities in oil*:*

$$\text{Ì}_{\text{á}} = \frac{\text{Ì}_{\text{á.ð}}\left(W_{\text{ì.ï}} + W_{\text{â}} + W_{x.c}\right)}{100}, \tag{4.5}$$

where $W_{м.п}$ – mass proportion of mechanical impurities in oil,%;

$W_{в}$ – proportion of water in oil, %;

$W_{x.c}$ – mass proportion of hydrochloric salts in oil, *%.*

Oil gross mass – total oil mass, including ballast mass. Thus, oil mass is expressed as:

$$M_{\text{í}} = \text{Ì}_{\text{á.ð}}\left(1 - \frac{\left(W_{\text{ì.ï}} + W_{\text{â}} + W_{x.c}\right)}{100}\right). \tag{4.6}$$

The main methods to measure **gross oil mass** are:

- *volume-mass dynamic method , using flow transducers (including ultrasonic) and line-in density transducers;*
- *mass dynamic method using mass meters.*

Regulations for exact mass measurement are in accordance to ***GOST 26976.***

4.2.2. Oil mass determination through oil quality measurement system (OQMS)

Oil mass in the pipeline is determined [50] during the delivery-distribution operation or oil stock-taking:

- *quantity measurement and quality oil factors;*
- *capacity measurement and full capacity measurement (horizontal, vertical, reinforced concrete tanks, railway and car tanks, tankers);*
- *shipping by tankers;*
- *shipping by railway tanks;*
- *in the pipeline.*

Structure of oil mass determination through OQMS

It includes software and metrological equipment (Fig.4.11), where oil mass is measured in the so-called measuring line unit. Not only are different parameters through measuring line obtained, but also oil density parameters through line-in densimeters which are installed in the measuring line.

***Measuring line** – structural or functional part of the measuring system, in which the process from received measurement value to measurement result is indicated.*

Measuring line system- measuring line includes several operation and control lines (Fig. 4.12, 4.13).

Measuring line system includes the following elements:

- *inlet and outlet valves;*
- *filters with differential pressure meters;*
- *drainage line;*
- *relief (safety) valve;*
- *stream (spout) rectifier;*
- *flowmeters;*
- *pressure and temperature transducer meters;*
- *flow controller.*

Oil quality measurement system (Fig. 4.12, 4.13) Oil enters the quality measurement unit through special samplers in accordance to GOST 2517. Isokinetic flow control is implemented through quality measurement system.

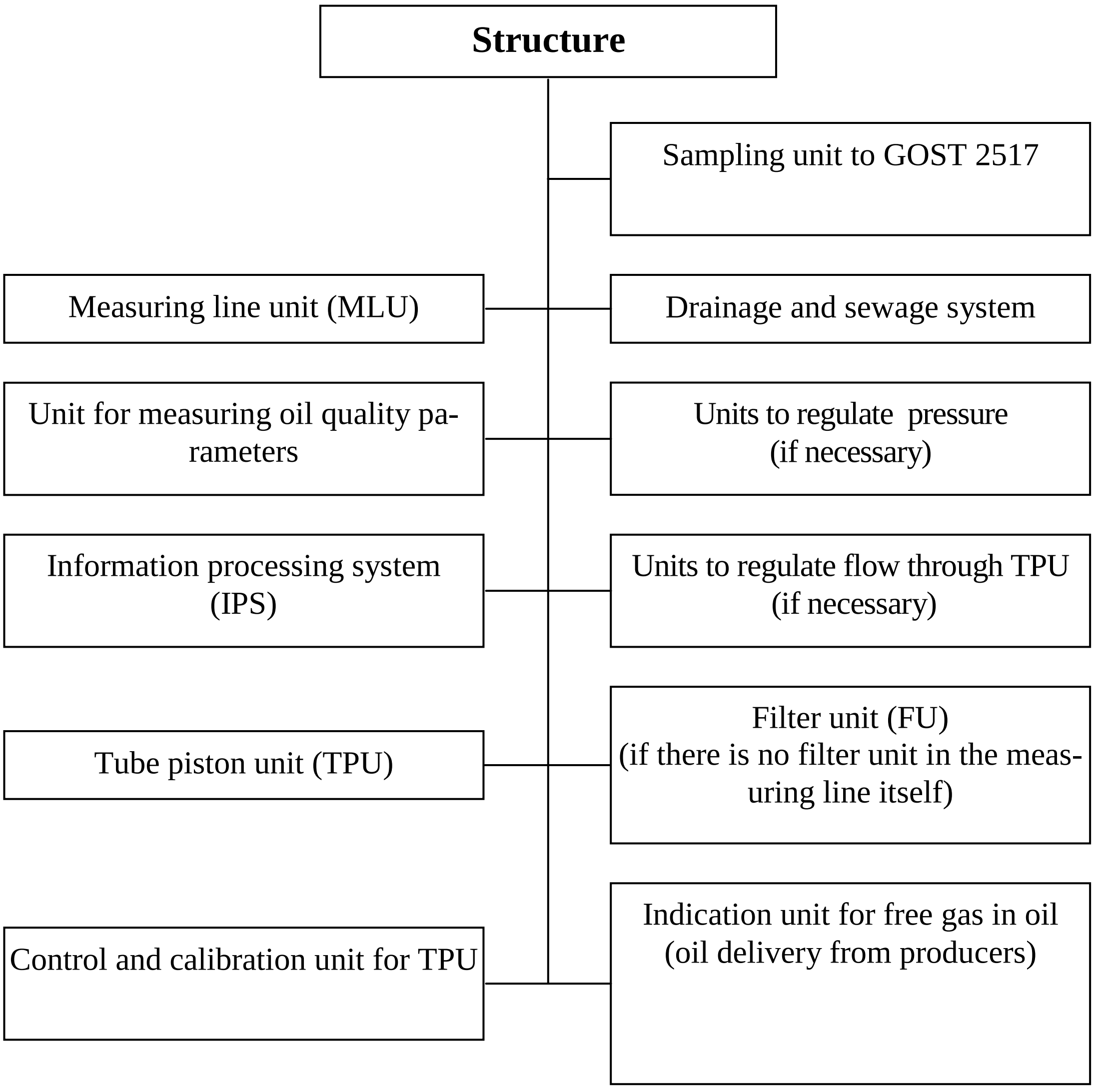


Fig . 4.11. Structure of oil mass determination through OQMS

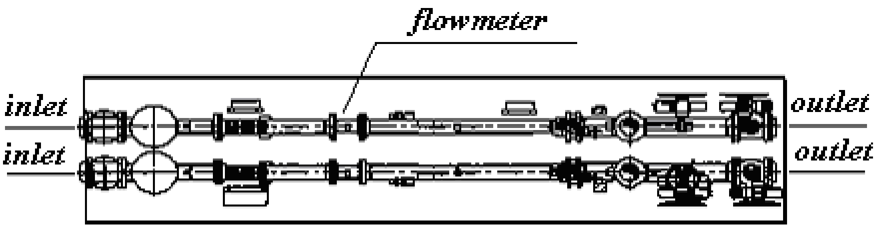


Fig.4.12.Illustration of typical measurement line system: vertical view

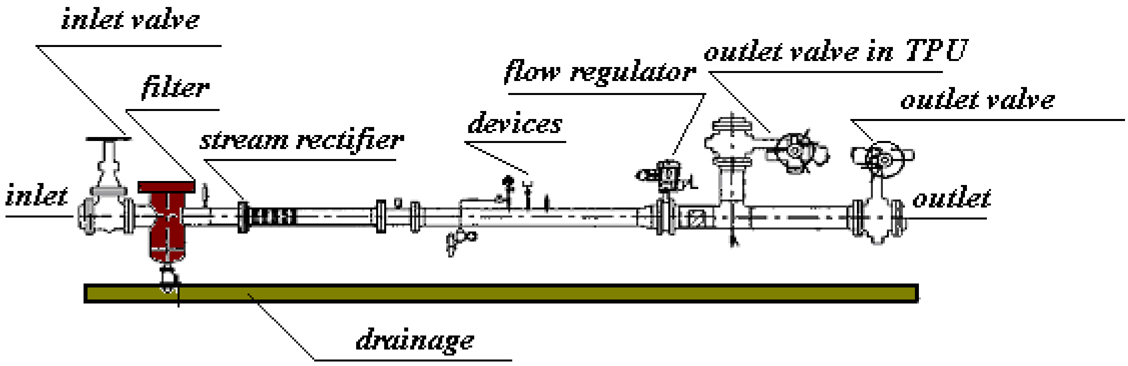


Fig. 4.13.Illustration of typical measurement line system: side (profile) view

Oil quality parameter measurement includes the control of technological equipment operation regime and product pumping regime. Quality document for transported oil (control-analytic laboratory) is necessary in the commodity-transportation operation. Besides the main and secondary measurement units there are the following installations:

- *automatic samplers (main and stand-by) for samples at given program, with sealed 3-liter containers;*
- *unit for manual point samples (for control-analytic laboratory).*

The quality measurement system includes unit for connection of densimeter installation next to the density transducers and a place to measure oil density by densimeter.

Information processing system *– computer to process measurement information (data) of quantity-quality oil parameters in the measurement system include indication units, registration and archiving measurement results.*

Information processing system includes the following operations:

- *calculation of total oil flow according to oil mass determination through oil quantity measurement and quality factor (indexes) system;*
- *oil flow calculation through quality measurement unit;*
- *oil density calculation;*
- *oil mass calculation;*
- *calculation of weight- mean temperature and pressure for each measurement system and oil mass determination through oil quantity measurement and quality factor (indexes) system;*
- *differential pressure measurement in the filters;*
- *determination of moisture-content in oil;*
- *monitoring of automatic samplers and their operation control;*
- *automatic control, indication, signaling and registration of limit oil parameter values;*

- *automatic control of operating flow transducers without troubleshooting of oil quantity and quality factor measurement process;*
- *monitoring TPU performance;*
- *free gas in oil;*
- *signaling of drainage leakages;*
- *fire protection and gas contamination control in premises*.

Tube piston unit to monitor and control meteorological flow transducer characteristics, installed in oil measurement control system (Table 4.4).

Control unit to monitor TPU by volume-mass method, based on meters and weights once in two years (Table 4.5.).

Table 4.4

Measurement units and equipment included in tube piston unit

Measurement unit/ equipment	Allowable error
Tube piston unit	$\Delta = \pm$ 0,09 %
Excess pressure transducer	$\Delta = \pm$ 0,6 %
Temperature transducer in the thermopocket	$\Delta = \pm$ 0,2˚C
Manometer	Class 0,6
Thermometer (mercurial, glass)	$\Delta = \pm$ 0,2˚C

Table 4.5

Measurement units and equipment in the control system

Measurement unit/ equipment	Allowable error
Static scales (floor)	2 class
Standard measuring tank	Once
Turbine flow transducer (to determine flow during control as indicator)	–
Manometer	Class 0,6
Thermometer (mercurial, glass) at the TPU outlet	$\Delta = \pm$0,2˚C
Solenoid-operated valve «usually open»	–
Solenoid-operated valve «usually closed»	–
Locking and regulating valve	–
Globe valve	–
Valve	–
Pump	–
Filter (mechanical net) before the pump	–
Check valve	–
Storage capacity	–

Oil mass measurement through direct and indirect dynamic measurement method

Gross mass of received and delivered oil through oil quantity measurement and quality factor (indexes) system is determined in accordance to "***Recommendations in determining net mass in calculations through oil quantity measurement and quality factor (indexes) system (Promenergo Ministry, March 31, 2005, № 69)"***:

- *indirect method of dynamic measurement* through volume flow transducers, including ultrasonic and in-line density transducers*;*
- *direct method of dynamic measurement* through mass meters.

In oil gross mass measurement through indirect dynamic measurement method, the following measurement results are indicated:

- *oil volume(m^3), measured by every flow transducer under standard operating conditions;*
- *oil volume (m^3), to standard conditions , measured through oil quantity measurement and quality factor (indexes) system;*
- *oil density(kg/m^3), measured by in-line densimeter at standard measured volume conditions;*
- *oil gross mass (m), measured in every operating pipeline and throughout oil quantity measurement and quality factor (indexes) system (oil gross mass is volume to density at measured volume conditions; volume and density under conditions to* ***GOST P 8.595-2004****).*

Flow meters (turbine, rotor, ultrasonic and blade), temperature and pressure transducers, data processing system are used to determine oil *volume*. In-line density transducers, pressure and temperature transducers data processing system are used to determine oil *density.*

Pressure transducer and manometer, temperature transducer and glass thermometer are installed at the outlet of every measurement system and at the inlet and outlet of control unit, while pressure transducer and manometer at the outlet of oil quantity measurement and quality factor (indexes) system manifold.

Through direct dynamic measurement method , oil gross mass is measured by mass meters and the measured oil mass results are automatically recorded (t), including every measured operating mass meter and oil quantity measurement and quality factor (indexes) system (Fig. 4.14).

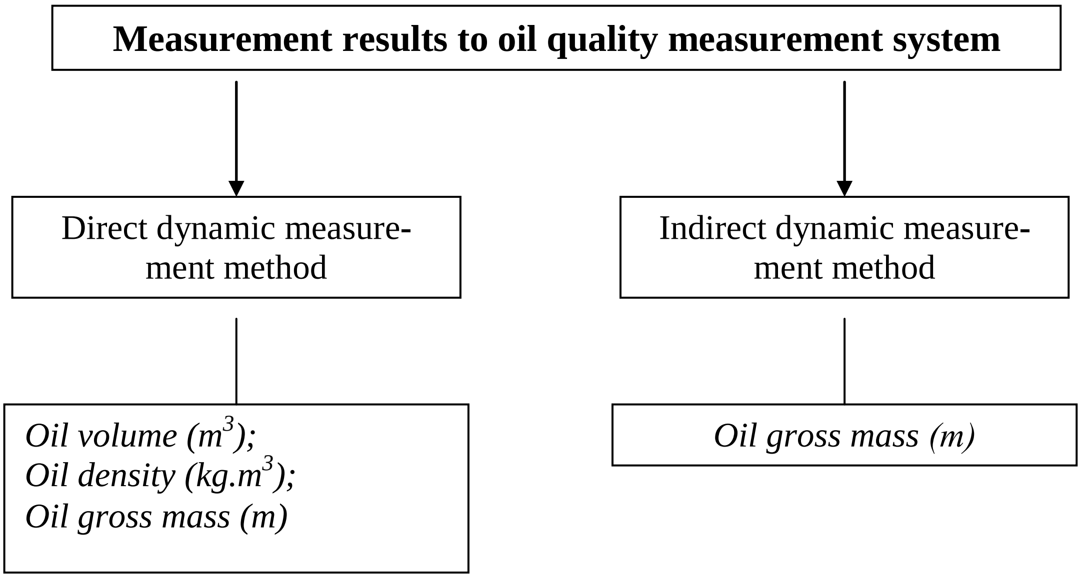


Fig. 4.14. Measurement results through oil quality measurement system to calculate oil quantity

Measurement results are recorded in special record-books every 2 hours or definite time intervals, regardless of applied method.

Measurement results and determination of oil quality factors are recorded in the so-called «Quality Record» as:

- *weighted average temperature, density and pressure values (for one shift);*
- *weighted average density at 20 ºC and 15 ºC (for one shift);*
- *laboratory measurement results in accordance to* ***GOST 51. 858-2002*** *[48, 50]*.

The following tables 4.6, 4.7, 4.8 show recommended oil quantity measurement and quality factor (indexes) system structure through direct and indirect methods to measure oil mass.

Table 4.6

Major measurement methods, based on oil quality measurement system

Measurement units and equipment in oil quality measurement system		Allowable error range for measurement units		Notes
Indirect dynamic measurement method	Direct dynamic measurement method	Indirect dynamic measurement method	Direct dynamic measurement method	
Measurement line unit				
Operating flow transducers, stand-by	Mass-metric, major & stand-by	± 0,15 %*	± 0,25 %*	
Flow transducer, control	Mass-metric-control	± 0,1 %**	± 0,20 %**	according to project-design
Pressure transducer				
Differential pressure transducer (diaphragm gauge) and gages in filters				to control filter contamination
Manometers				
Temperature transducers with sensors (thermoresistivity), group A				
Thermometers (glass)				scale division 0,1 ºC
Filters				If in oil quantity measurement and quality factor (indexes) system, then no installed filters in measurement system

Valves or globe valves (shutoff valves), electric drive, including current shut-off and equipped with sealed control units (*)		–	only in shut-off valves, unsealed, which affects the measurement results during monitoring and control of meterological flow transducer characteristics
Orifice box	None	–	according to project-design
Flow regulators		–	
Samplers (installed in oil quantity measurement and quality factor (indexes) system)		–	according to GOST 2517
Pressure regulator at the oil quantity measurement and quality factor (indexes) system outlet		–	according to project-design
Quality measurement unit			
In-line density transducer – major and stand-by		± 0,36 кг/м^3 ****	–
Pressure transducers		± 0,5 % ***	–
Manometers		± 0,6 % ***	–
Thermometers (glass)		± 0,2 ºC ****	scale division 0,1 ºC
Temperature transducers with senors(thermoresistivity), group A		± 0,2 ºC ****	–
Flowmeter		± 5,0 %*	–
Automatic samplers (major and stand-by) with dispersant		–	according to GOST 2517
Samplers for manual sampling		–	
Flow regulator (**)		–	
Circulation pump			possible application of no-pump operation scheme in necessary flow in Quality measurement unit

Table 4.7

Major measurement methods, without the technological oil quality measurement system

Measurement units and equipment in oil quality measurement system	Allowable error range for measurement units	Notes
Data processing system	±0,05%	where there is no possibility in applying flow transducer without secondary device
Secondary flow transducer	±0,05%	-
Automation of production unit (operator)	-	in new and re-constructed oil quantity measurement and quality factor (indexes) system and according to project-design
Stationary monitoring unit (control and calibration unit for TPU)	I or II category	at one and the same area as oil quantity measurement and quality factor (indexes) system

Table 4.8

Supplementary measurement units and equipment for oil quality measurement system

Measurement units and equipment in oil quality measurement system		Allowable error range for measurement units		Notes
Indirect dynamic measurement method	Direct dynamic measurement method	Indirect dynamic measurement method	Direct dynamic measurement method	
1		2		3
Density transducer, stationary and standard in quality measurement unit	no	± 0,1 кг/м^3 ****	–	according to project-design

Viscosity transducer in quality measurement unit	no	± 1,0 % ***	–	according to project-design
Moisture-content in-line transducer (major and stand-by) quality measurement unit				
Sulphur-content in-line transducer quality measurement unit with measurement ranges: 0…0,6 % 0,1…1,8 % 1,8…5,0 %		± 0,02 % ± 0,06 % ± 0,18 %		
Units for conversion coefficient adjustment	no	±0,05%	-	according to project-design; transformation coefficient correction of flow transducer at operating scale division 2 or more; no totalizer installed in data processing unit.
Totalizer(device)	–	± 0,05 %	–	In a case of 2 or more working meter runs and absence of in-built function in information system.
Control indicator for free gas		–		according to project-design
Thermo-static cylinder in quality measurement unit		–		
Circulation pump in quality measurement unit		–		
Gas- indicator in quality measurement unit		–		–

1	2	3
Fire protection indicator in quality measurement unit	–	–
Air-exhauster (vacuum fan) in quality measurement unit	–	–
Electric heater with thermo-regulator in quality measurement unit	–	–

** – allowable relative error range in flow range;*
*** – allowable relative error range in flow point;*
**** – allowable conditioned error range;*
***** – allowable absolute error range.*

The following main and additional parameters are controlled in the operation process of oil quality measurement system (Table 4.9, 4.10, 4.11).

Table 4.9

Main monitoring (controlling) parameters in oil quality measurement system operation through direct and indirect dynamic measurement

Parameters	Notes
Oil flow through measurement system	flow mean is within operating flow range, according to volume or mass flow transducer control certificate
Excess oil pressure after flow transducer	provide non-cavitation work (operation) regime of flow transducer, where excess pressure is determined and has the following value: $$P = 2{,}06P_н + 2\Delta P, \quad (4.7)$$ where P – minimum excess pressure value after flow transducer; $P_н$ – saturated vapor pressure, determined in accordance to GOST 1756 at maximum oil temperature in oil quantity measurement and quality factor (indexes) system, mPascals; ΔP – differential pressure at flow transducer, given in specification Report for this type, mPascals *
Differential pressure in filters	Not more than given value in Report for this filter type or not more than $2\Delta P_ф$, where $\Delta P_ф$ – differential pressure in filter at maximum flow, determined for specific oil quantity measurement and quality factor (indexes) system after the cleaning-out filter
Oil flow through quality measurement unit	• excludes meteorological failure of in-line transducers, installed in QMU (deviation exception of meteorological characteristics from normal values); • reliability and descriptive features of samples

** Example- Problem : $P_н$ – 500 mm mercury column = 0,067 mPascals; ΔP= 0,05 mPascals.*

Solution: $P = 2{,}06P_н + 2\Delta P = 2{,}06 \times 0{,}067 + 2 \times 0{,}05 = 0{,}24\,mPascals$. *Thus, minimum excess pressure value after flow transducer is not more than 0,24 mPascals.*

Table 4.10

Additional monitoring (controlling) parameters in oil quality measurement system operation through direct dynamic measurement

Parameters	Notes
Zero offset of mass meter	control of zero offset in accordance to specifications for specific mass meter type

Table 4.11

Additional monitoring (controlling) parameters in oil quality measurement system operation through indirect dynamic measurement

Parameters	Notes
Value f/ν	where f – current outlet frequency flow transducer; ν – oil viscosity if values f/ν are controlled, then flow value is not controlled
Oil viscosity	if there is no unit or algorithm in transducer coefficient correction for flow transducer to change viscosity, then oil viscosity is not different from the value for turbine meter control, i.e not more than: • $\pm 2\times10^{-6}$ m^2/sec – for turbine flow transducers, «Turbokvant», «Nort-M»type (Dy from 40 to 200); • $\pm 5\times10^{-6}$ m^2/sec – for turbine flow transducers «Rotokvant» type(Dy from 150 to 400), «Mig» type(Dy up to 150); «Smith»type (Dy up to 200); • $\pm 10\times10^{-6}$ m^2/sec – for turbine flow transducer «Mig»type (Dy more than 150); «Smith» type (Dy more than 200). for other flow transducer types viscosity measurement range is not more than the value, given in the type-description according to research results

Periodical control of measurement units in oil quality measurement system

All measurement systems of oil quality measurement system are included in primary and periodical monitoring of State meteorological service. Periodical monitoring is done through schedules, developed by owners of oil quantity measurement and quality factor (indexes) system and approved by meteorological service executives and maintenance organizations. (Table 4.12).

Table 4.12

Periodical control of measurement units in oil quality measurement system

Средство измерения	Периодичность поверки
Scale weights	Once a year
Weights, used to check weight	Once a year
Dosimeter - portable	Once a year
Dosimeter and scale weights, stationary installed ; purpose- to check TPU	Once in two years
Stationary TPU	Once in two years
Portable TPU	Once a year
Flow transducer- stand-by and operating control-stand-by (including, mass meter)	Once a year
Standard flow transducer	Once a year
Densimeter	Once a year
Standard densimeter	Once a year
In-line transducers of density, temperature and pressure, manometer, installed not in measurement system БИК, secondary flow transducer devices, totalizer, measuring instruments and equipment, viscosity manifold.	Once a year
Glass thermometer, installed in measurement system QMU	Once in three years
Transducers of moisture-content, viscosity, sulphur-content	Once a year
Level gage, used in tank control scheme	according to type description
Information System	Once in five years
Tank, used in the tank control scheme	Once in five years

Example

Oil monitoring unit FMC Energy Systems Co. USA

Illustration view of oil monitoring unit FMC Energy Systems Co. is depicted in Fig. 4.15, and specification characteristics in Tables 4.13, 4.14

Fig. 4.15. Illustration of measurement system unit FMC Energy Systems, USA

Table 4.13

Specification parameters in measurement system to flow

Flow in measurement system	According to certificate	According to check certificate
Minimum	14 m^3	21 m^3
Maximum	140 m^3	84 m^3

Table 4.14

Specification parameters in measurement system to pressure

Pressure	According to certificate	In measurement system Meter Run Unit	In system QMU
Minimum	0,3 mPascals	0,3 mPascals	0,3 mPascals
Maximum	5,1 mPascals	5,1mPascals	5,1 mPascals

Oil is transported by tank and trunk pipeline through inlet tank and outlet valves *HOV*-type (installed on measurement system). Outlet valves isolate the pipeline in case of repair or maintenance. Under normal conditions, this valve is open, so that the flowmeter is always full.

There is a filter *STR-type* (Fig. 4.16) with air valves designed to expel large amounts of air at low pressure during filling and release small amounts of pressurized air during operation. This filter entraps solid extraneous particles which, in their turn, could damage the internal flowmeter mechanism. The pipeline measurement filter is not designed to clean or filter oil products. There is differential pressure meter *PDIT-* type installed on the filter, which controls the differential pressure in the filter when the "basket" is full.

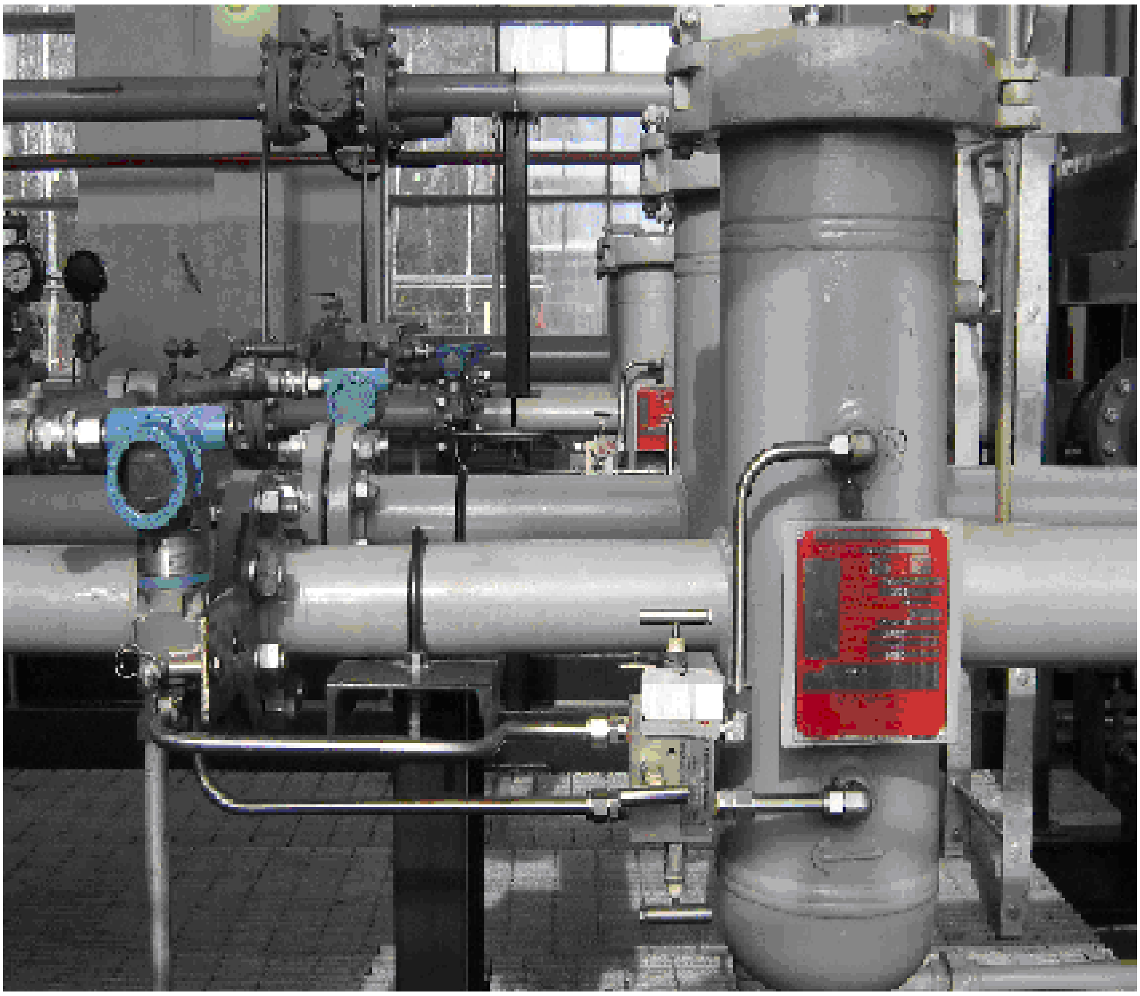


Fig. 4.16. Filter STR-type, differential pressure meter PDIT-type

High differential pressure indicates that the filter "basket" must be cleaned to prevent further damage. There is a drainage line with valves connected to the common drainage system. The drainage valves are sealed during the pipeline performance to prevent oil leakage in the drainage tank of oil quantity measurement and quality factor (indexes) system.

Relief valves admit air to the pipe while the pipe is being drained to prevent excessive vacuum pressures (as a result of thermal expansion of oil products) and reduce the possibility of collapsing thin-walled pipes

Further, the flow enters the stream rectifier section, which includes stream rectifier unit *CL*-type and tube with flanges. This section is installed only if there is no straight-run pipe more than *20 Dy* of the pipeline before the turbine flow transducer. The high-effective flow rectifier unit is located on *10 Dy* length of the pipeline. Stream rectifier section decreases flow turbulence and deformation, when the oil flows through valves, pumps and filters and other pipeline configuration units. This creates regular load on the flow transducers, providing exact performance and, in its turn, affects the meteorological parameters of pipe-piston control unit (PPCU).

Then, the transformation of spiral rotor rotation frequency occurs in the flowmeter (for example, turbine rectifier type FE), proportional to the moving amount of fluid, into electrical impulse signals. Amplifiers transform meter rotation into square-wave signals. Such signals transfer fluids into secondary computer devices.

The following meters- pressure transducers, temperature transducers, which transfer signals from the operating system (Fig. 4.17), are installed next to the flowmeters. Manometers and thermometers are installed for local control.

Shutoff block valve *MOV-2* is installed after the measurement section (Fig. 4.18). It includes hermetic control measurement pipeline with reciprocating unit manifold. If the pipeline is under normal operating conditions, then the valve is shut off. When the valve is shut off, the plug (slug) is driven down between the slips, unclamping them so as the slip surface enters the slot seat, which in its turn, completely locks the flow at both sides of the valve. As the valve is hermetic, the fluid pressure should not be higher than the allowable internal chamber pressure. In this case, excess pressure is discharged. Safety thermal expansion valve operates only when the valve is shut off. It operates before the valve itself, if the pressure increases in the pipeline.

Then the oil moves through the control flow valve - *FCV* (Fig. 4.19). This valve controls fluid flow through turbine flow transducer depending on the adjusting input flow signal from the computer.

After the control valve the following valves are installed on the measurement line:

- *two-sided shut off block valve MOV-2, connecting the measuring line with control measuring line through MOV-3, with input check unit through valve MOV-4;*
- *two-sided shut off block valve MOV-5, connected to control measuring line with input manifold TPU.*

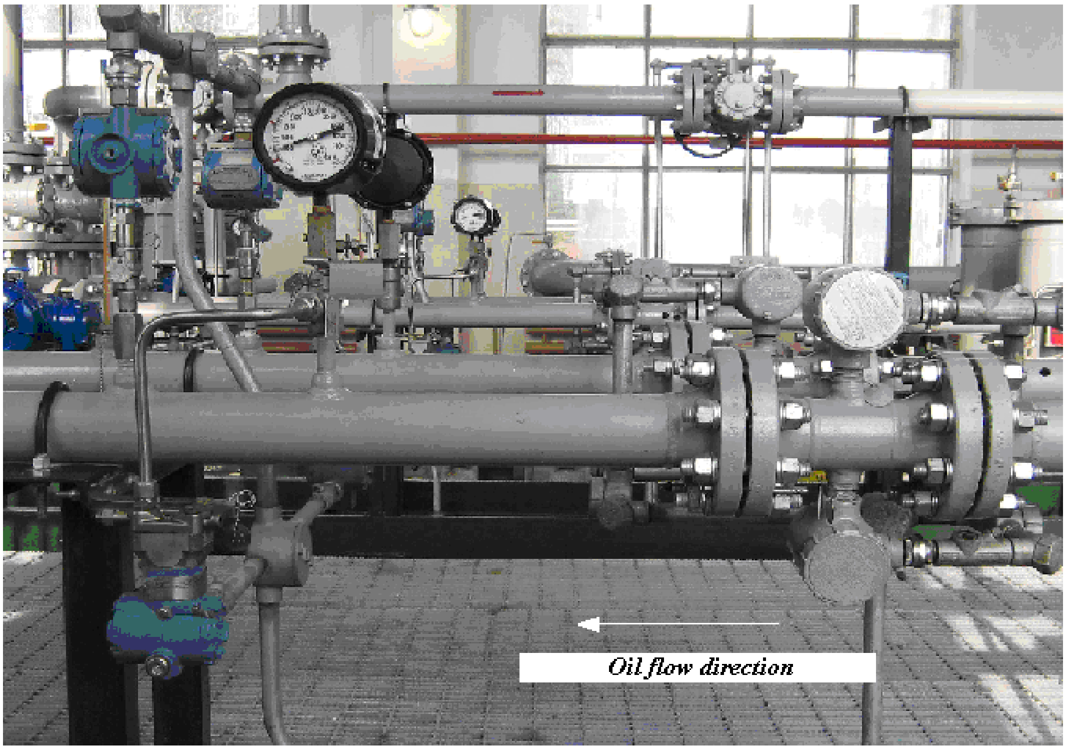


Fig. 4.17. Turbine flow transducer, type FE with amplifier-FT, pressure transducer –PT, temperature transducer-TT

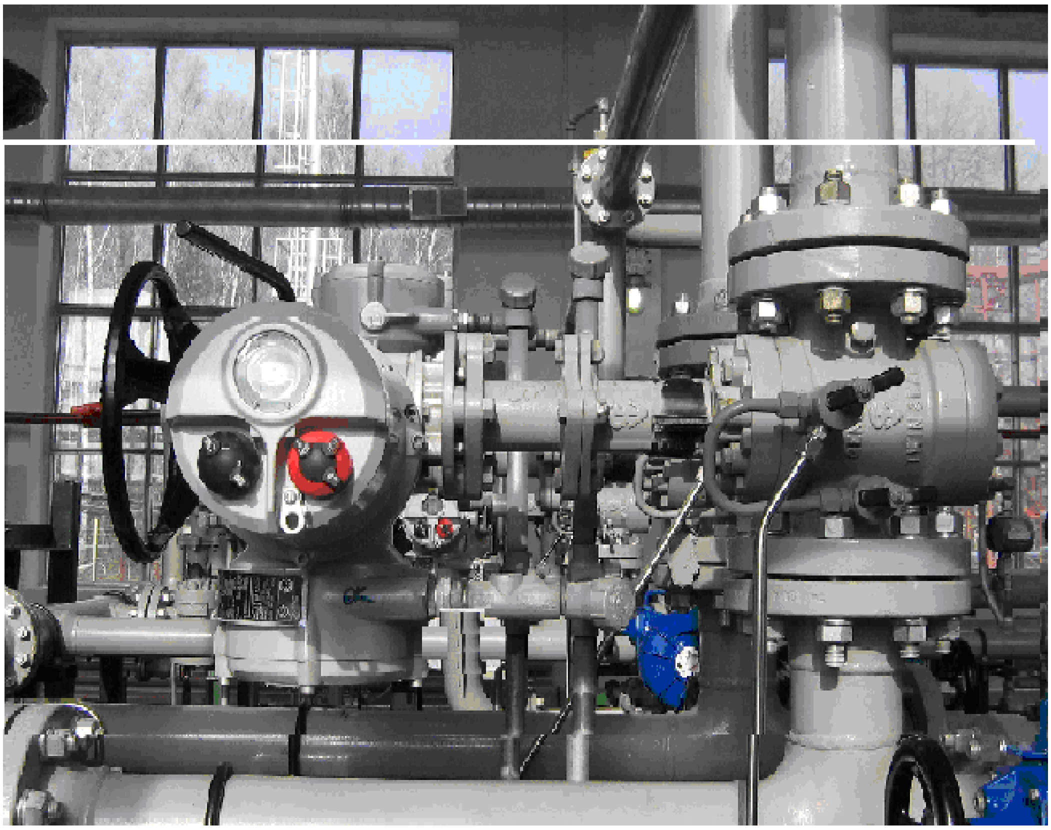


Fig. 4.18.Shut off block valve- MOV-2 Side view

Valves *MOV-2* and *MOV-5* are shut off under operating conditions of measuring line. These valves are opened only under the following conditions: checking, metrological characteristic control of operating flowmeters in accordance to standards, as well as, exceptional metrological characteristic control of flowmeter or TPU.

During measuring line operation the input valves- *HOV* and output valves – *MOV-6* are open and fluid flow enters the input oil control tank. Primary indicator phase transducer is installed at the output tank measuring line to control free gas in the fluid flow. If free gas is detected, a secondary unit is installed to transmit sound signals. Further, the oil moves through industrial pipeline, electro-conductive valve to pressure regulator, then to trunk pipeline.

Fig. 4.19. Control flow valve- FCV

4.2.3. Oil Mass Determination in Storage Capacity Units and Ultimate Capacity Units

In case of measurement units failure, which in its turn, makes it impossible to implement OQMS, the reserve control scheme is applied.

In the shortest possible time- from failure to reserve scheme transition - the transported oil volume is determined through calculations. The following flow parameters – pressure, temperature, density- are equal average values of the last reporting period. Flowrate value is equal to the fixed value for the last two hours under invariable pumping regime.

Table 4.15

Cases showing reserve control scheme application

Case	Description
Simultaneous failure of flow transducer , filter or jet rectifier on the operating and stand-by measuring lines	In those cases, when the flowrate through one measuring line is higher than the allowable working range of flow transducer, according to control standards
Viscosity value inclination without unit for correction transformation factor of turbine flow transducer to viscosity	more than: • *±2×10^{-6} м^2/sec – turbine flow transducers «Turbokvant», «Nord-M» (Dy from 40 to 200);* • *±5×10^{-6} м^2/sec – turbine flow transducers «Rotokvant» (Dy from 150 to 400), «MIG» (Dy from to 150); «Smith» (Dy up to 200);* • *±10×10^{-6} м^2/sec – turbine flow transducers «MIG» (Dy more than 150); «Smith» (Dy more than 200);* • *Other flow transducer types where viscosity measurements is not higher than the stated value in instruction description*
Reconstruction and scheduled service operations , necessary to cease OQMS	Only under mutual agreement conditions of both sides
Electricity cut off	absence of reserve power supply
Oil leakage through valves or in cases of valve breakdowns	Valves are installed on bypass line of OQMS
Emergency	impossible operation of OQMS (fire)

Oil Volume Determination in Storage Capacity Units

Oil volume in storage capacity units is determined by:

- *indirect statistic measurement method;*
- *direct statistic measurement method;*
- *indirect method based on hydrostatic principle*.

Indirect statistic measurement method determines the oil volume in storage capacity units through calibration chart. Oil density is measured by densimeter or in laboratories through integral oil samples, selected from storage capacity units, according to ***GOST 2517***. Oil gross mass is determined as the product of oil volume and density or oil volume and oil density under standard conditions.

Direct statistic measurement method- measures mass of empty storage capacity unit and storage capacity unit with oil on scales. Gross oil mass is calculated as the difference between storage capacity unit with oil and empty storage capacity unit.

Indirect method based on hydrostatic principle – oil mass calculation is based on the measurement results of oil hydrostatic pressure column and special calibration charts. The quantity control of standard (inspected) and delivered oil is measured through *indirect statistic measurement method* by using tanks after two-hour settling-out in tanks and drainage of commercial water and impurities. The oil level is measured by level gages, measuring tapes according to **GOST** ***7502*** or electronic tapes. Commerical water level is measured by level gauges, measuring tapes through water-sensitive tapes or paste, electronic measuring units.

Storage capacity measurement using *indirect statistic measurement method, direct statistic measurement method and indirect method based on hydrostatic principle* are conducted according to the following regulations:

- *capacity of steel vertical cylindrical tanks* ***(GOST 8.570 and MP 1124);***
- *capacity of steel horizontal cylindrical tanks* ***(GOST 8.346);***
- *capacity of concrete tanks(**РД 50-156 and MP 2778**);*
- *capacity of railway tanks(**ISR 65**);*
- *capacity of trunk tanks (**GOST P 8.569**);*
- *capacity of marine tanks(**MP 2579**).*

Measurement of oil level and commercial water by level gauges or electronic tape is conducted according to level gage or electronic tape operating requirements.

Measurement of oil level by measuring tape where the tape is thoroughly wiped before and after the measurement. The base tank height is the vertical distance from the bottom to the top edge of the measuring hatch. The results are compared to base height requirements for each particular tank.

If base height (H_b) differs from the results to not more than 0,1 % of H_b, then the oil level measurement by the tape is conducted in the following sequence:

- *the tape with a load is lowered slowly to the bottom tray or back-up deck without any inclination of the tray from vertical position, without touching inner devices, without any wave formation and preserving steady oil surface;*
- *the tape is then lifted vertically without any side-way inclinations and reading point is the oil-wetted part of the tape.*

The accuracy of these readings is up to 1mm.The fluid level measurement is performed twice in each tank. If the measurement result difference is not more than 1mm, then the average value is accepted. If the measurement result difference is more than 1mm, then the measurement is performed twice and the average value is calculated as the closest value of the three.

If the base height differs from the obtained results more than 0.1% of the base height itself, then the reasons for such changes are considered and eliminated as soon as possible. The base height is measured once a year. In the above-mentioned case, the oil level is measured according to the empty tank height.

Measurement of oil level to empty tank height by measuring tape where the tape with a load is lowered slowly to the bottom tray or back-up deck without any inclination of the tray from vertical position, without touching inner devices, without any wave formation and preserving steady oil surface. The first reading (upper reading) is the measurement at the risk level of the measured hatch panel. The tape is then lifted vertically without any side-way inclinations and reading point is the oil-wetted part of the tape (bottom reading).

The accuracy of these readings is up to 1mm.The fluid level measurement is performed twice in each tank. If the measurement result difference is not more than 1mm, then the average value is accepted. If the measurement result difference is more than 1mm, then the measurement is performed twice and the average value is calculated as the closest value of the three. Emptiness height is the difference between upper and lower readings. The oil level is determined as the subtraction of obtained emptiness height value from required tank base height value.

Measurement of commercial water level in tanks by measuring **tapes** which are water indicator tapes or paste in the following sequence

- *tight water indicator tapes are attached to the tray surface on two opposite sides.*
- *water indicator paste is a thin layer (0,2…0,3 mm)on the tray surface on two opposite sides.*
- *The tape and tray with water indicator paste or attached water indicator tape during determination of commercial water level is in the tank for 2-3 minutes; the water indicator layer completely dissolves and the boundary between water and oil layers is sharply displayed.*

The commercial water level measurement is conducted twice in every tank. If the measurement result difference is not more than 1mm, then the average value is accepted. The commercial water level measurement is repeated if this measurement is not distinct (slant curve or different height on both sides), which in its turn, indicates that the tray is inclined during the measurement. Such a blurred line is the result of no distinct boundary between water and oil and the presence of aqueous layer. In this case, the measurement is repeated after emulsion settling and separation.

Determination of factual (actual) oil volume in the tank Total oil volume in the tank and commercial water volume is determined through calibration chart for every specific tank. Factual oil volume in a tank is calculated as

$$V_{н} = V_0 \left[1 + (2\alpha_{ст} + \alpha_s) \cdot (t_{ст} - 20) \right], \qquad (4.7)$$

where $\boldsymbol{V_0}$ *– oil volume in a tank through calibration chart, m*^{3} *is determined as*

$$V_0 = V_{fv} - V_{cwv}, \qquad (4.8)$$

where $\boldsymbol{V_{fv}}$ *– fluid volume (oil and commercial water), determined through calibration chart of a tank, at temperature 20ºC according to GOST 8.570, m*^{3}*;*

$\boldsymbol{V_{cwv}}$ *– commercial water volume determined through calibration chart of a tank, at temperature 20ºC according to GOST 8.570, m*^{3}*;*

$\boldsymbol{\alpha_{cm}}$ *– temperature coefficient of linear tank wall material expansion, equal to* $12{,}5\cdot10^{-6}$ *1/℃;*

$\boldsymbol{\alpha_s}$ *– temperature coefficient of measurement level gage material expansion (stainless tape), where* α_s *equals* $12{,}5\cdot10^{-6}$*, 1/℃. If oil level measurement by tape to empty tank height and level gages, then* $\alpha_s = 0$*;*

$\boldsymbol{t_{cm}}$ *– tank wall temperature equals oil temperature in the tank.*

Determination of oil density in capacity units. Oil density is measured by densimeters according to operation requirements for each specific type or GOST ***3900*** and GOST ***P51069*** for combined oil samples. Density values are adjusted to measured oil volume temperature in the tank and to standard conditions in accordance to **MP *2153*** or **MP *2632.***

Determination of oil temperature in capacity units Average oil temperature is determined by stationary temperature transducers or temperature transducers with electronic tapes in accordance to operation requirements in level measurement or manual measurement of separate samples.

Oil temperature is determined by thermometers for combined samples according to GOST ***2517.*** In separate samples oil temperature is determined during 1...3 minutes after the selection, where mobile sampling device is sustained at the sample level for less than 5 minutes. Thermometer is merged in oil to corresponding mercury column level (in accordance to requirements).

Average oil temperature is calculated as the temperature of separate samples, applying the combined sample ratio from separate samples, according to GOST ***2517*** [47, 50, 51].

Determination of gross oil mass in capacity units Gross oil mass (tonne) in capacity units are calculated as

$$M_{бр} = V_O \rho_O \times 10^{-3}, \tag{4.9}$$

where, $\boldsymbol{\rho_o}$ *– oil density at temperature of oil volume in tank, kg/m^3;*
$\boldsymbol{V_o}$ *– factual oil volume in tank, m^3.*

Determination of gross oil mass during pumping from capacity units During pumping operating oil mass is determined as the difference between initial mass and remaining mass. Operating oil mass M_{oper} is

$$Moper = Miom - Mro, \tag{4.10}$$

where, $\boldsymbol{M_{iom}}$ *– oil mass before pumping, m;*
$\boldsymbol{M_{ro}}$ *–remaining oil mass, determined after pumping from the tank, m.*

Determination of gross oil mass during pumping from capacity units During pumping oil into capacity units (tanks, marine tanks, railway tanks), accepted oil mass $\boldsymbol{M_{acc}}$ is calculated as

$$M_{пр} = M_{н2} - M_{н1}. \tag{4.11}$$

Determination of ballast content in oil in capacity units Determining ballast content in oil is conducted in research laboratory through samples, selected in accordance to GOST ***2517.***

Automatic oil mass measurement- through level gages included in the automatic control system. Oil density is determined through АСУ density measurement or combined oil samples, selected in accordance to GOST 2517. Oil temperature is measured automatically through automatic temperature control system.

Determination of oil mass in full capacity units

In oil mass measurement of full capacity units by *indirect statistic measurement method,* oil volume is determined by measurement records of full capacity. Oil density is measured by mobile densimeter or laboratory method for separate oil samples. Gross oil mass is the product of oil volume and oil density at volume measuring conditions or the product of oil volume and oil density at standard conditions. Oil temperature in full capacity units is measured by thermometer in separate oil samples.

In oil mass measurement of full capacity units by *direct statistic measurement method,* mass of emptied capacity unit and mass of full oil capacity unit are measured on weights. Gross oil mass is calculated as the difference between mass in full oil capacity unit and emptied capacity unit.

Determination of oil mass during shipping in marine tanks is conducted according to coastal OQMS data by direct method and indirect method of dynamic measurement. Indirect statistic measurement method (for tanks) is for stand-by measurement scheme.

Stand-by measurement tools are marine tanks with approved calibration charts and special ***correction factor K*** (according to MI *1001),* including full capacity tank value inclination from its calculated calibration value due to different factors (inaccuracy of calibration charts, unremoved residuum, tank deformation, etc).

Oil mass measurement in tanks by *indirect statistic measurement method,* oil volume is determined by tank calibration charts, applying oil level measurement results in the tanks and commercial water level. Oil density is measured by mobile densimeter or in laboratory by combined oil samples. Gross oil mass is determined as the product of oil volume and oil density at volume measuring conditions or the product of oil volume and oil density at standard conditions. Oil temperature in full capacity units is measured by thermometer in separate oil samples

Oil level and commercial water in tanks are measured after oil settling for less than 30 minutes.

Determination of oil mass during shipping in railway tanks are determined by the following methods:

- *based on results of filling railway tanks with oil, using OQMS;*
- *direct statistic measurement method;*
- *indirect statistic measurement method.*

Oil level in railway tanks is measured after a 30-minute oil settling. Oil density is measured by mobile densimeter or in laboratory by combined oil samples. Gross oil mass is determined as the product of oil volume and oil density at volume measuring conditions or the product of oil volume and oil density at standard conditions.

Oil mass measurement in railway tanks by direct statistic method is when connected (disconnected) tanks are weighted and gross oil mass in these tanks is the difference between gross mass before and after the oil loading (unloading) in weighted tanks.

4.2.4. Determination of oil mass in pipelines

Gross oil mass in the pipeline is the total oil mass in separate pipeline sections. The calculation of pipeline sections are those where the pressure difference between final and initial section points is not more than 0.3mPascals. Obtained result is approximated to whole tonne value:

$$M_{тр} = \sum_{i=1}^{n} M_{уч}\,, \tag{4.12}$$

*where, **n** – number of sections;*

***$M_{уч}$** – gross oil mass in separate pipeline sections, determined as the product of geometric inner pipeline volume and average oil density value in this pipeline section:*

$$M_{уч} = V_{у} \frac{\rho_{ср}}{1000}, \tag{4.13}$$

For gravity pipeline sections:

$$M_{уч} = K_{з} \times V_{уч} \frac{\rho_{ср}}{1000}, \tag{4.14}$$

*where, **$V_{уч}$** – pipeline section capacity, m^3;*

***$\rho_{ср}$** –average oil density value in the section, kg/m^3;*

***$K_з$** – coefficient of full pipeline, determined according specific method or calibration chart **P 50.2.040-2004**.*

Considering the influence of average temperature and pressure values in this section, the pipeline section capacity is calculated as

$$V_{уч} = V_{гр} \times K_{t} \times K_{p}\,, \tag{4.15}$$

*where, **$V_{гр}$** – pipeline section capacity, determined in accordance to specific calibration charts, m^3;*

***K_t** – coefficient including temperature influence (specific charts, in accordance to P 50.2.040-2004);*

***K_p** –coefficient including pressure influence (specific charts, in accordance to P 50.2.040-2004).*

The average temperature, pressure and density value for this specific pipeline section as part of the crude trunk pipeline and product pipeline is determined as average corresponding arithmetic value, measured at the initial and final pipeline sections during stock-taking:

$$t_{\text{ср}} = 0{,}5 \cdot (t_{\text{нач}} + t_{\text{кон}}),\ \rho_{\text{ср}} = 0{,}5 \cdot (\rho_{\text{нач}} + \rho_{\text{кон}}),\ \ P_{\text{ср}} = 0{,}5 \cdot (P_{\text{нач}} + P_{\text{кон}}), \tag{4.16}$$

Pipelines with preliminary heated oil:

$$taver = 1/3 \cdot tinit + 2/3 \cdot tfinal\ , \tag{4.17}$$

where ρ_{init}*,* ρ_{final} *–oil density, measured at the initial and final pipeline sections and average temperature and pressure, kg/m*^{3}*;*

- $P_{initial}$*,* P_{final} *– pressure, measured at the initial and final pipeline sections, mPascals;*
- $t_{initial}$*,* t_{final} *– temperature, measured at the initial and final pipeline sections, °C.*

If during the stated period in filling up the section before stock-taking, density changes (same as temperature) to more than 5 kg/m^3 , then the average density value is calculated as

$$\rho_{\text{ср}} = \frac{1}{V_{\text{уч}}} \cdot \sum_{j=1}^{k} Q_j \cdot \rho_j\ , \tag{4.18}$$

where $V_{уч}$ *– pipeline capacity;*

- Q_j *– oil volume j, measured at the beginning of the pipeline section;*
- ρ_j *– oil density j, measured at the beginning of the pipeline section;*
- k *–amount to fill the pipeline section.*

Amount of oil **k** is determined as

$$\sum_{j=1}^{k} Q_j \cdot \left[1 + \beta\left(t_{\text{ср}} - t_{\text{нач}}\right) + \gamma\left(P_{\text{нач}} - P_{\text{ср}}\right)\right] = V_{\text{тр}}\ , \tag{4.19}$$

where, β*,* γ *– oil volume expansion and compression coefficients, determined according to MP 2632, °C*$^{-1}$ *and mPascal* $^{-1}$ *, respectively.*

Ballast oil mass portion $m_{тр}$, %, in the pipeline is calculated as weighted average value to corresponding magnitude, determined at the initial pipeline section at the moment of filling:

$$m_{\text{тр}} = \frac{1}{M_{\text{тр}}} \cdot \sum_{j=1}^{k} m_j \cdot Q_j \cdot \rho_j = \frac{1}{M_{\text{тр}}} \cdot \sum_{j=1}^{k} m_j \cdot M_j\ , \tag{4.20}$$

where, m_j *– ballast mass portion in the initial pipeline section at the moment of filling in,%;*

- $M_{тр}$ *– gross oil mass in the pipeline, m;*
- M_j *–oil mass- j, m.*

Gross oil mass in the crude trunk and product pipeline includes:

$$M_{\text{н}} = M_{\text{тр}} \cdot (1 - 0{,}01 \cdot m_{\text{тр}}). \tag{4.21}$$

4.3. Measurement Error

Error Types

Measurement error - the discrepancy between the results of the measurement -$X_∂$. and the value of the quantity measured - X_n. Technician is interested in the following results of error measurement, which includes many constituents. The variety of errors and their condition origin is due to constituent division. There are 30 different error constituents and measurement results (instrumental, procedural, basic, additional, statistic, dynamic, additive, multiplicative, etc.). The above-mentioned error constituent terms are constantly enlarged.

There are two main measurement error properties- long-term dynamic error measurement changes (during operation) and their changes in time. Thus, truncation errors are excluded as they are the result of measurement unit application procedures, and only those errors made by measurement units are considered, i.e. instrumental, errors stated in instructions.

Errors which do not change in time are insufficient accuracies of measurement unit samples used during calibration. Such measurement unit calibration errors may be exacting systematic, and therefore, are eliminated by including corresponding corrections for measurement results. Such is the case if there is a correction chart for each scale grade. And, visa versa, if there is it not used, then such measurement errors are random, as they can be positive, negative or even zero. Thus, it is not only random, but also invariable constituent in time.

To consider changing procedures of measurement unit errors in time, all errors are divided into the following groups: instrumental and procedural, random and systematic, basic and additional. All mentioned will be discussed further.

Instrumental and procedural errors

This classification division is very important when considering the measurement unit error dynamics during operation time as there is a continuous increase of only measurement unit instrumental errors. According to ***GOST 16263 – 70*** instrumental errors (device, apparatus) are those that are specific for only one measurement unit, i.e. determined through testing and indicated in the corresponding requirement certificate.

There are also those errors which occur as the result of procedure application, i.e. they are not stated in the requirement certificate. Such errors are called procedural ones.

Recently, the term «procedural error» has another meaning – those errors as a result of the procedure itself, independent of those conditions stated by designers and producers (especially for digital devices). Quantization errors in digital devices are unavoidable, as they are due to the information digital presentation method itself. Thus, it is termed «procedural» to highlight the fact that the error magnitude does not depend on its intensification. However, such errors should be indicated as instrumental in the requirement certificate according to ***GOST 8.009 – 84.***

The most frequent reason for procedural errors is the fact that usually the wrong value or even approximate value is measured or could be measured. For example, method choices of a device design to measure fuel in a car tank. So, the total fuel energy is determined by its mass (but not volume) and a scale is necessary for its measurement. However, combining the fuel tank and scales complicates the design; and the designer substitutes the scales by a simple floating level gauge. The following factor should be taken into consideration: fuel level depends on the dip of the tank, as well as, fuel temperature and mass. Designers consider device errors caused by temperature and dip to be «procedural» errors, i.e. conditioned by chosen procedure. These errors are specific device instrumental error for the user, and thus, are stated in the requirement certificate.

There are some cases when it is very difficult to indicate the measurement method without procedural errors. For example, temperature measurement of hot-red block. Where can the temperature meter be placed- at the side or above the block? It’s impossible to measure the internal temperature of the block, no matter where the meter is located. Thus, there is a possibility of considerable procedural error, as we are measuring not what is necessary, but what is simpler. Such detailed errors can not be indicated in the measurement unit requirement certificate, and furthermore, is not an instrumental error, but a procedural one.

Basic and additional errors

The major measurement unit error which is applied under normal conditions, are those conditions indicated in standard-technical requirements. Normal influencing values are indicated as standard or technical conditions for each specific measurement unit as nominal with normal inclinations. The most common normal conditions are the following:

- *temperature (20 ± 5) ºC;*
- *relative moisture (65±15) %;*
- *atmosphere pressure (100 ± 4) кPascals or (750 ± 30) mm of mercury column;*
- *electricity supply voltage 220 B ± 2% with frequency 50 hertz.*

Nominal value range is sometimes indicated instead of the normal influencing values; for example, moisture (30…80) %. Additional measurement unit error is the measurement unit error constituent occurring, as an additional error to the basic one due to some inclination of the influencing value from the its normal magnitude. The division- basic and additional errors - is based on the fact that the measurement unit properties depend on external conditions.

Thus, such a division is only conventional and is determined by regulation requirements, in which the following conditions for each specific measurement unit are stated- «normal» or «operating».

Systematic, progressive and random errors

Systematic errors are those errors that don't change in time or those errors that are constant in time to specific influencing factor functions. The major specific characteristic is that such errors can be completely eliminated by only introducing corresponding corrections. The main drawback in this case is the presence of constant systematic errors which, in its turn, is very difficult to detect. The only method is repeated testing of the unit according to sample measurements.

Progressive (drift) errors are those errors that slowly change in time. These errors are due to different factors: ageing processes of various device units: power supply discharge, ageing of transformers, resistors and condensers, deformation and elasticity changes of mechanical units, paper tape shrinkage of registering apparatus and others. The specific characteristic of progressive errors is the fact that correction is introduced at the present moment. However, these errors can monotonously increase once more. Thus, in comparison to systematic errors which are corrected only once during the device operating life, the progressive errors include constant repeating correction; the more frequent the correction, the less is the remaining value. Another specific characteristic is that the change in time is time-dependent random process; and if based on the well-developed theory of time-dependent random processes, these errors can be described only as exceptions.

Random errors are unpredictable to either value or size of these errors (in other words, insufficiently studied). They are determined through a total of complex factors which are difficult to analyses. Random errors (in comparison to systematic ones) are easy to detect by repeated measurements as obtained result scattering. Thus, the main characteristic feature of random errors is unpredictability during their evaluation readings

Thus, description of random errors is based on the probability theory, only with some significant exceptions. «Random value» is a narrow term with many limited conditions in comparison to the term «random error» applied in measurement unit.

Bands of measurement unit errors

The combined interaction of all instrumental measurement unit errors results in the fact that calibration characteristics of meters, devices, data-measuring systems (DMS) and measuring-calculating systems (MCS) are ambiguous and irreproducible. Experimental determination, i.e. calibration indicates points on the chart, positioned in a band by a main average curve. This curve is nominal calibration characteristic of measurement unit, although there are several inclined experimental points. These inclinations have specific terms.

Random scattering from one to another reading\ from one device to another is called reproducibility errors. Systematic inclinations from selected smooth curves are generally called errors of selected approximable functional dependence adequacy (straight line, parabola) and are factual measurement unit characteristics. If a straight line is selected, its adequacy error is called linear measurement unit error. If adequacy error changes its sign in accordance to previous readings of initial value alteration, then such device error or transducer is called hysteresis error or measurement unit variation.

Total function of all these values result in multiple device characteristic measurements or series of one-type devices indicate a certain band on the chart. Thus, the term ambiguity band or error band for a specific device, meter, data-measuring systems (DMS) and measuring-calculating systems (MCS) is used. The error of a specific measurement transducer, meter, device or data-measuring system is the difference between real and nominal characteristics, i.e. the function of measuring value (but not its number).

Additive and multiplicative constituent bands of measurement unit errors are used to describe band boundary forms of these measurement unit errors.

If absolute measurement unit error throughout its operating range has restricted constant margin $\pm\Delta$ (independent of current value x), such error is called additive or zero error (experimental point is within parallel boundaries to each other). This term is applied in both cases: random and systematic errors.

Multiplicative errors (sensitive errors) are those errors when the measurement unit error band width increases proportional to the increase of initial values x, where $x = 0$. However, there are no devices with pure multiplicative error band, because it is impossible to develop such a device with zero error value at $x = 0$. In this case, such a device could only measure any small values. Such additive errors as noise, drift, induction, vibration, etc. are unavoidable in any measurement units. Thus, additive and multiplicative constituents are an arithmetic sum and this error band has a trapeziform.

Standardization of Measurement Unit Error

Critical error valves are the extremely allowable value margins of real error models. If real measurement unit errors are within critical margins, the measurement unit is considered to be metrological corrected; if visa versa, then it should be withdrawn and repaired or regulated. Correspondence of measurement unit error to its critical margin is checked during regular periodical testing. This is based on uniform specifications (including critical error margins, forms and their readings). Main method determination of allowable error margin and their accurate measurement unit groups are described in accordance to ***GOST 8.401 – 80***. Different measurement units are used: *absolute, relative* and *modified* error values.

Absolute measurement unit errors- measurement unit error is depicted in the following measurement values:

$$\Delta X = X_n - X_\delta . \tag{4.22}$$

Absolute errors are convenient in practical applications, as the error value is a measurement value. However, in some cases, it is very difficult to compare device accuracies with various measurement ranges. This problem is solved when applying relative errors.

If absolute error does not change throughout the measurement range, it is called additive; but if it changes proportional to measuring value (increases to increasing error), it is multiplicative.

Relative measurement unit errors δ – measurement unit error, expressed as the ratio of absolute measurement unit error $\boldsymbol{\Delta X}$ to measurement result or real measurement value $\boldsymbol{X_\delta}$

$$\delta = \frac{\Delta X}{X_\delta} . \tag{4.23}$$

Relative error indicates the accuracy measurement level for a specific measurement unit. However, this error type significantly changes in the device scale, i.e. increases when measurement value decreases. In this case, the modified error is used.

Modified measurement unit errors γ – relative error as the ratio of absolute measurement unit error to conditioned modified value $\boldsymbol{X_N}$, which is called critical,

$$\gamma = \frac{\Delta X}{X_N} , \tag{4.24}$$

or reading range dimension,

$$\gamma = \frac{\Delta X}{X_к - X_н} , \tag{4.25}$$

where «***к***» and «***н***» - end and beginning of measurement, respectively.

Relative and modified errors are expressed in % or relative units (unit fraction).

Critical values for indicators are determined according to the scale features. Modified errors are compared to accuracy measurement units, having different measurement margins, if in its turn, the absolute error of each measurement unit does not depend on the measurement value itself.

Modified error is convenient in those cases when multi-margin measurement units have one and the same values (not only for all points in every subrange, but also for all subranges, exclusively). This is convenient for critical error of multi-margin devices.

Thus, accuracy group for most measurement units is expressed in % of critical, i.e. margin value of modified error:

$$\gamma_{\hat{e}\ddot{e}} = \gamma_{\ddot{\imath}\eth}. \tag{4.26}$$

Meteorological ageing process features of measurement units

In time the elements and units in manufactured and regulated measurement devices age and steady error inclination increases. To provide long-term operation life of different measurement units, «ageing margin» is introduced, i.e. device series have factual errors which are less than their critical margin. The gradual decrease of this margin provides the long-term meteorological operating life of the device.

The main factor, determining the measurement unit ageing, is not the nonfailure operating time, but the device operating schedule, including the production date (i.e. device age). Measurement unit ageing velocity is determined by those processes at the molecular level and depend on applied material and production technology. Thus, ageing velocity not only electro-mechanical, but also electronic devices is determined by established production technology and can be significantly changed without drastic production alterations [52, 53].

4.4. Orifice Natural Gas Flow Measurement through Angle Tapping

Measurement Conditions

1 All measurements should be carried out in accordance with GOST 8.586.1 (items 5, 6 and 7).

2 When applying measurement system, environmental characteristics must be conformed to the measurement system realization conditions stated by manufacture.

3 The range of applied measurement system must not be less than the range of the value being measured.

4 Metrological characteristics of measurement system are specified to provide required uncertainty of flow measurement results.

5 Power supply SI (International system of units) characteristics in operating conditions should correspond to SI characteristics approved by the manufacture.

6 Measurements should be done using SI (International system) units calibrated in accordance to application field.

7 SI (International system of units) is applied in conformity with operational requirements.

Initial Data

Table 4.16

Measurement Initial Data

Value Title	Symbolic Notation	Measurement Unit	Numerical Value
Orifice diameter at temperature 20 °C	d_{20}	mm	200
Sensing line inner diameter at temperature 20 °C	D_{20}	mm	300
Mean absolute error of sensing line roughness profile (new, seamless, cold-drawn pipe)	Ra	m	0,00001
Orifice diameter at temperature 20 °C	d_{20}	mm	200
Orifice material	Steel grade 12X18H10T		
Sensing line material	Steel grade 09Г2С		
Initial radius of orifice entry edge	$r_{н}$	mm	0,04
Carbon dioxide content in natural gas (NG)	$x_{у}$	1	0,005 (0,5)
Nitrogen content in natural gas (NG)	$x_{а}$	1	0,025(2,5)
NG density in standard conditions	$\rho_{с}$	kg/m^3	0,72
Relative humidity of natural gas	φ	%	0
Pressure drop across an orifice	Δp	kgf/cm^2	0,63
Accessible pressure	$p_{н}$	kgf/cm^2	40
Natural gas temperature	t	°C	5

Gas Flow Rate

1. The orifice and sensing line diameters in operational conditions are calculated in dependence on material grade in accordance with GOST 8.586.1 [19].

2. The following formulas are applied for diameter value d calculation:

$$d = d_{20}K_{cy}, \tag{4.27}$$

$$d = 200 \cdot 0{,}99756 = 199{,}951,$$

$$K_{cy} = 1 + \alpha_{t\,cy}(t - 20), \tag{4.28}$$

$$K_{cy} = 1 + 0{,}0001623888(5–20) = 0{,}99756,$$

where $\boldsymbol{\alpha_{t\,cy}}$ *– temperature coefficient of material linear expansion.*

2. Depending on sensing line material grade GOST 8.586.1 [19], D is calculated as follows:

$$D = D_{20}K_{T}, \tag{4.29}$$

$$D = 300 \cdot 0{,}999839 = 299{,}9517,$$

$$K_{T} = 1 + \alpha_{t\,T}(t - 20), \tag{4.30}$$

$$K_m = 1 + 0б00010740025(5\text{-}20) = 0{,}999839,$$

where $\boldsymbol{\alpha_{tT}}$ *– temperature coefficient of sensing line material linear expansion.*

$$\alpha_{tcy} = 10^{-6}[a_0 + a_1(t/1000) + a_2(t/1000)^2] =$$
$$10^{-6}[16{,}206 + 6{,}571(5/1000) + 0(5/1000)^2] = 0{,}00001623888,$$
$$\alpha_{tT} = 10^{-6}[a_0 + a_1(t/1000) + a_2(t/1000)^2] =$$
$$10^{-6}[10{,}680 + 12{,}000(5/1000) + 0(5/1000)^2] = 0{,}000010740025.$$

The value of linear expansion temperature coefficient for various materials is calculated by the formula G.1 GOST 8.586.1 [19], given in annex Г.

3. Relative orifice diameter is calculated in accordance with GOST 8.586.1 [19], respectively β:

$$\beta = \frac{d}{D}, \tag{4.31}$$

$$\beta = 199{,}951/299{,}9517 = 0{,}666612.$$

4. The formula GOST 8.586.1 [19] is applied for entrance velocity coefficient E calculation

$$E = 1\Big/\sqrt{1-\beta^4}, \tag{4.32}$$

$$E = 1\Big/\sqrt{1-0{,}666612^4} = 1{,}116267.$$

5. Let us calculate correction factor $K_П$, including entry edge dulling.

If the orifice entry edge radius r_K does not exceed *0,0004d*, correction factor $K_П$ equals unity, GOST 8.586.2, items 5.3.2.4 [20].

If r_K value exceeds *0,0004d*, correction factor $K_П$ is calculated as follows

$$K_П = 0{,}9826 + \left(\frac{r_К}{d} + 0{,}0007773 \right)^{0{,}6}, \qquad (4.33)$$

$$r_К = \alpha - (\alpha - r_Н) e^{\left[-\tau_T / 3 \right]}, \qquad (4.34)$$

$$r_k = 0{,}195 \cdot 10^{-3} - (0{,}195 \cdot 10^{-3} - 0{,}04) e^{(-1/3)} = 0{,}02866,$$

$$K_n = 1.$$

where $\boldsymbol{\alpha}$ *– parameter considering fluid type being measured, which is specified as* $0{,}19 \cdot 10^{-3}$ *for liquids,* $0{,}195 \cdot 10^{-3}$ *for gas, and* $0{,}2 \cdot 10^{-3}$ *for vapor;*

$\boldsymbol{r_H}$ *– orifice entry edge initial radius;*

$\boldsymbol{\tau_T}$ – orifice operation time from the moment of entry edge initial radius $r_н$ being defined, year.

For other material grades $K_П = 1$.

6. Value ε is calculated in accordance with GOST 8.586.2 [20].

$$\varepsilon = 1 - \left(0{,}351 + 0{,}256\beta^4 + 0{,}93\beta^8\right)\left[1 - \left(1 - \frac{\Delta p}{p}\right)^{1/\kappa}\right], \qquad (4.35)$$

$\varepsilon = 1 - (0{,}351 + 0{,}256 \cdot 0{,}666612^4 + 0{,}93 \cdot 0{,}666612^8)[1 - (1-)^{1/1{,}331917}] = 0{,}994813$

where $\boldsymbol{\kappa}$ *– adiabatic index (Kobsa formula)* GOST 30319-96 [27].

The formula 4.35 is applied only for values *β*, *D* and *Re* mentioned in 5.3.1 GOST 8.586.2 [20] under the condition that

$$\frac{\Delta p}{p} \leq 0{,}25.$$

$$\frac{61{,}7819 \text{ кПА}}{3922{,}66 \text{ кПа}} = 0{,}01575 \textit{that meet condition} \leq 0{,}25.$$

7. In dependence on flow rate unit, Reynolds number is calculated as follows:

$$Re = \frac{4q_m}{\pi D_\mu}, \qquad (4.36)$$

Flow rate is calculated in the following way:

а) take first approximation of Reynolds number value equal to 10^6;

б) calculate first approximation of flow coefficient value C_1;

в) determine first approximation value $K_{Ш1}$;

г) depending on the selected measurement units, apply one of the following formulas 5.2…5.4, 5.6…5.8 [23], calculate the first approximation of flow rate value q_1;

д) determine the second approximation of Re_2, C_2, $K_{Ш2}$ and q_1 values based on obtained q_1 value, formulas given in Table 6 being applied;

е) Re, C, $K_Ш$ and q values correction is done until relative divergence value between obtained flow rate value q_i and its previous value q_{i-1} meets the following condition

$$\frac{|q_i - q_{i-1}|}{q_i} < 10^{-5}, \qquad (4.37)$$

i.e. relative divergence should be 0,000..%.

The determined value q_i is taken as a target value of flow rate.

$$Re_1 = 10^6$$

$$Re_2 = 4 \cdot 42{,}15324 / 3{,}14 \cdot 0{,}3 \cdot 1{,}10689 \cdot 10^{-5} = 16177502{,}4$$

$$Re_3 = 4 \cdot 42{,}16666 / 3{,}14 \cdot 0{,}3 \cdot 1{,}10689 \cdot 10^{-5} = 16170529{,}18$$

$$Re = \frac{4q_c\rho_c}{\pi D_\mu}, \qquad (4.38)$$

8. Flow coefficient is determined in accordance with GOST 8.586.2 [20]

$$C = 0{,}5961 + 0{,}0216\beta^8 + 0{,}000521\left(\frac{10^6\beta}{Re}\right)^{0,7} + (0{,}0188 + 0{,}0063A)\beta^{3,5}\left(\frac{10^6}{Re}\right)^{0,3} +$$
$$+\left(0{,}043 + 0{,}08e^{-10L_1} - 0{,}123e^{-7L_1}\right)\times,$$
$$\times(1 - 0{,}11A)\frac{\beta^4}{1-\beta^4} - 0{,}031\left(M_1 - 0{,}8M_1^{1,1}\right)\beta^{1,3} + M_2, \qquad (4.39)$$

$C_1 = 0{,}5961 + 0{,}0261 \cdot 0{,}666612^8 - 0{,}216 \cdot 0{,}666612^8 + 0{,}000521 \cdot (10^6 \cdot 0{,}666612 / 1000000)^{0,7} + (0{,}0188 + 0{,}0063 \cdot 0{,}0030345995) \cdot 0{,}666612^{3,5} \cdot (10^6 / 1000000)^{0,3} + 0{,}043 + 0{,}08e^{-10\cdot 0} - 0{,}123e^{-7\cdot 0})\cdot(1 - 0{,}11 \cdot 0{,}0030345995) \cdot 0{,}666612^4 / 1 - 0{,}666612^4 - 0{,}031 \cdot (5{,}999016161 - 0{,}8 \cdot 5{,}999016161^{1,1}) \cdot 0{,}666612^{1,3} + 0 = 0{,}605035.$

$C_2 = 0{,}5961 + 0{,}0261 \cdot 0{,}666612^8 - 0{,}216 \cdot 0{,}666612^8 + 0{,}000521 \cdot (10^6 \cdot 0{,}666612 / 16177502{,}4)^{0,7} + (0{,}0188 + 0{,}0063 \cdot 0{,}003273197) \cdot 0{,}666612^{3,5} \cdot (10^6 / 16177502{,}4)^{0,3} + 0{,}043 + 0{,}08e^{-10\cdot 0} - 0{,}123e^{-7\cdot 0})\cdot(1 - 0{,}11 \cdot 0{,}003273197) \cdot 0{,}666612^4 / 1 - 0{,}666612^4 - 0{,}031 \cdot (5{,}999016161 - 0{,}8 \cdot 5{,}999016161^{1,1}) \cdot 0{,}666612^{1,3} + 0 = 0{,}601308.$

$C_3 = 0{,}5961 + 0{,}0261 \cdot 0{,}666612^8 - 0{,}216 \cdot 0{,}666612^8 + 0{,}000521 \cdot (10^6 \cdot 0{,}666612 / 16170529{,}18)^{0,7} + (0{,}0188 + 0{,}0063 \cdot 0{,}003274326) \cdot 0{,}666612^{3,5} \cdot (10^6 / 16170529{,}18)^{0,3} + 0{,}043 + 0{,}08e^{-10\cdot 0} - 0{,}123e^{-7\cdot 0})\cdot(1 - 0{,}11 \cdot 0{,}003274326) \cdot 0{,}666612^4 / 1 - 0{,}666612^4 - 0{,}031 \cdot (5{,}999016161 - 0{,}8 \cdot 5{,}999016161^{1,1}) \cdot 0{,}666612^{1,3} + 0 = 0{,}601307.$

$$A = \left(\frac{19000\,\beta}{Re} \right)^{0,8}, \tag{4.40}$$

$A = (19000 \cdot 0,666612 / 10^{6})^{0,8} = 0,0030345995.$

$A = (19000 \cdot 0,666612 / 16177502,4)^{0,8} = 0,003273197.$

$A = (19000 \cdot 0,666612 / 16170529,18)^{0,8} = 0,003274326.$

$$M_1 = \frac{2L'_2}{1-\beta}, \tag{4.41}$$

$M_1 = 2 \cdot 0 / 1 - 0,666612 = 5,999016161.$

$$M_2 = \begin{cases} \dfrac{0,011(0,75-\beta)\left(2,8 - \dfrac{D}{0,0254}\right) \text{ при } D < 0,07112\,м}{0 \text{ при } D \geq 0,07112\,м} \end{cases}, \tag{4.42}$$

For angle tapping, L_1 and L'_2 values are taken equal to $L_1 = L'_2 = 0$. M_2 equals =0 as $D > 0,07112m$.

9. Let us consider correction factor $K_Ш$

If arithmetic average divergence value of roughness profile *Ra* exceeds the value *Ra max* determined from the formula 5.8 GOST 8.586.2 [20] or if it is less than the value *Ra min* determined from the formula 5.10 GOST 8.586.2 [20], correction factor $K_Ш$ is calculated as follows

$$K_Ш = 1 + 5,22\beta^{3,5}(\lambda - \lambda^*), \tag{4.43}$$

$K_{Ш1} = 1 + 5,22 \cdot 0,666612^{3,5} \cdot (0,33029577 - 0,029806543) = 1,00422.$

$K_{Ш2} = 1 + 5,22 \cdot 0,666612^{3,5} \cdot (0,330295587 - 0,029806548) = 1,00459.$

$K_{ш3} = 1 + 5,22 \cdot 0,666612^{3,5} \cdot (0,330295694 - 0,029806652) = 1,00527.$

where $\boldsymbol{\lambda}$ and $\boldsymbol{\lambda^*}$ – friction coefficients, determined with the real *Re* number and sensing line equivalent roughness being equal to its real value $R_Ш$ (See item 7.1.5 GOST 8.586.1 [20]) and conventional value $R^*_Ш$, respectively.

λ and λ^* values are calculated as follows

$$\lambda = \left\{ 1,74 - 2lg\left[\frac{2A_Ш}{D} - \frac{37,36lg(k_D - k_R lg(k_D + 3,3333k_R))}{Re} \right] \right\}^{-2}, \tag{4.44}$$

where $\boldsymbol{A_Ш}$, $\boldsymbol{k_D}$, $\boldsymbol{k_R}$ – values calculated in accordance with Table *4.17 [20]*.

Table 4.17

*λ and λ*values*

Values	Calculation Values	
	λ	λ*
$A_Ш$	$R_Ш$ или πRa	πRa_{max} при $Ra > Ra_{max}$; πRa_{min} при $Ra < Ra_{min}$
k_D	$0{,}26954 R_Ш / D$	$0{,}26954 \pi Ra_{max} / D$ при $Ra > Ra_{max}$; $0{,}26954 \pi Ra_{min} / D$ при $Ra < Ra_{min}$;
k_R	$5{,}035/Re$	

$$\lambda_1 = \{1{,}74 - 2lg[2 \cdot 0{,}15 / 0{,}3 - 37{,}36lg(0{,}13477 - 0{,}00000503lg(0{,}13477 + 3{,}3333 \cdot 5{,}03^{-7} / /10^6))]^{-2} = 0{,}33029577.$$

$$\lambda_1^* = \{1{,}74 - 2lg[2 \cdot 0{,}001413 / 0{,}3 - 37{,}36lg(0{,}00038086 - 0{,}00000503lg(0{,}00038086 + 3{,}3333 \cdot 5{,}03^{-7} / 10^6))]^{-2} = 0{,}029806543.$$

$$\lambda_2 = \{1{,}74 - 2lg[2 \cdot 0{,}15 / 0{,}3 - 37{,}36lg(0{,}13477 - 0{,}00000503lg(0{,}13477 + 3{,}3333 \cdot 5{,}03^{-7} / /16177502{,}4))]^{-2} = 0{,}330295587.$$

$$\lambda_2^* = \{1{,}74 - 2lg[2 \cdot 0{,}001413 / 0{,}3 - 37{,}36Lg(0{,}00038086 - 0{,}00000503lg(0{,}00038086 + 3{,}3333 \cdot 5{,}03^{-7} / 16177502{,}4))]^{-2} = 0{,}029806548.$$

$$\lambda_3 = \{1{,}74 - 2lg[2 \cdot 0{,}15 / 0{,}3 - 37{,}36Lg(0{,}13477 - 0{,}00000503Lg(0{,}13477 + 3{,}3333 \cdot 5{,}03^{-7} / /16170529{,}18))]^{-2} = 0{,}330295694.$$

$$\lambda_3^* = \{1{,}74 - 2lg[2 \cdot 0{,}001413 / 0{,}3 - 37{,}36Lg(0{,}00038086 - 0{,}00000503lg(0{,}00038086 + 3{,}3333 \cdot 5{,}03^{-7} / 16170529{,}18))]^{-2} = 0{,}029806652.$$

10. Flow rate calculation.

Flow rate is calculated in the units of mass rate, volume flow rate in operating conditions and corrected volume flow rate (standard conditions are prescribed by GOST 2939).

The correlation between mass flow rate, volume flow rate in operating conditions and corrected volume flow rate is given by the following formula

$$q_m = q_c \rho_c = q_v \rho . \tag{4.45}$$

$$42{,}16666 = 58{,}5648 \cdot 0{,}72 = 1{,}30189 \cdot 32{,}388.$$

Mass flow rate is calculated as follows

$$q_m = 0{,}25\pi\, d_{20}^2 K_{cy}^2 CEK_Ш K_П \varepsilon (2\Delta p \times \rho)^{0,5} . \tag{4.46}$$

$$q_m = 0{,}25 \cdot 3{,}14 \cdot 200^2 \cdot 0{,}9997564168^2 \cdot 0{,}605035 \cdot 1{,}116267 \cdot 1{,}00422 \cdot 1 \cdot 0{,}994813(2 \cdot 61781{,}9 \cdot 32{,}388)^{0,5} = 42{,}16477 \text{ кг/с}.$$

$$q_m = 0{,}25 \cdot 3{,}14 \cdot 200^2 \cdot 0{,}9997564168^2 \cdot 0{,}601308 \cdot 1{,}116267 \cdot 1{,}00459 \cdot 1 \cdot 0{,}994813(2 \cdot 61781{,}9 \cdot 32{,}388)^{0,5} = 42{,}16534 \text{ кг/с}.$$

$$q_m = 0{,}25 \cdot 3{,}14 \cdot 200^2 \cdot 0{,}9997564168^2 \cdot 0{,}601307 \cdot 1{,}116267 \cdot 1{,}00527 \cdot 1 \cdot 0{,}994813(2 \cdot 61781{,}9 \cdot 32{,}388)^{0,5} = 42{,}16666 \text{ кг/с}.$$

Volume flow rate in operating conditions is calculated by the following formula

$$q_v = 0{,}25\pi\, d_{20}^2 K_{cy}^2 CEK_{Ш} K_{П} \varepsilon \left(\frac{2\Delta p}{\rho} \right)^{0,5}. \qquad (4.47)$$

$q_v =$ 0,25 · 3,14 · 200^2 · 0,9997564168^2 · 0,605035 · 1,116267 · 1,00422 · 1 · 0,994813(2 · 61781,9 / 32,388)^{0,5} = 1,30084 *кг/с.*

$q_v =$ 0,25 · 3,14 · 200^2 · 0,9997564168^2 · 0,601308· 1,116267 · 1,00459 · 1 · 0,994813(2 · 61781,9 / 32,388)^{0,5} = 1,30121 *кг/с.*

$q_v =$ 0,25 · 3,14 · 200^2 · 0,9997564168^2 · 0,601307 · 1,116267 · 1,00527 · 1 · 0,994813(2 · 61781,9 / 32,388)^{0,5} = 1,30189 *кг/с.*

Corrected volume flow rate is calculated as follows

$$q_v = 0{,}25\pi\, d_{20}^2 K_{cy}^2 CEK_{Ш} K_{П} \varepsilon \left(\frac{2\Delta\, p\, \rho}{\rho_c} \right)^{0,5}. \qquad (4.48)$$

$q_c =$ 0,25 · 3,14 · 200^2 · 0,9997564168^2 · 0,605035 · 1,116267 · · 1,00422 · 1 · 0,994813 (2·61781,9·32,388)^{0,5}/0,72=58,5648 *кг/с.*

$q_c =$ 0,25 · 3,14 · 200^2 · 0,9997564168^2 · 0,601308· 1,116267 · 1,00459 · 1 · 0,994813 (2·61781,9·32,388)^{0,5}/0,72=58,5648 *кг/с.*

$q_c =$ 0,25 · 3,14 · 200^2 · 0,9997564168^2 · 0,601307 · 1,116267 · · 1,00527 · 1 · 0,994813 (2·61781,9·32,388)^{0,5}/0,72=58,5648 *кг/с.*

If fluid density in operating conditions is calculated as

$$\rho = \frac{\rho_c p T_c}{p_c T K}. \qquad (4.49)$$

then the formulas (4.46)…(4.48) can be written as:

$$q_m = 0{,}25\pi\, d_{20}^2 K_{cy}^2 CEK_{Ш} K_{П} \varepsilon \left(2\Delta p \times \rho_c \frac{pT_c}{p_c T K} \right)^{0,5}. \qquad (4.50)$$

$$q_m = 0{,}25\pi\, d_{20}^2 K_{cy}^2 CEK_{Ш} K_{П} \varepsilon \left(2\Delta p \frac{p_c T K}{p_c p T_c} \right)^{0,5}. \qquad (4.51)$$

$$q_m = 0{,}25\pi\, d_{20}^2 K_{cy}^2 CEK_{Ш} K_{П} \varepsilon \left(2\Delta p \frac{pT_c}{\rho_c p_c T K} \right)^{0,5}. \qquad (4.51)$$

Task and Discussion Questions

1. What is the pipeline metering station intended for? Describe its structure.
2. What is the difference between direct and indirect oil mass measurement methods? What methods are applied?

3. Describe oil measurement methods in tanks.
4. Describe the structure of oil quality measurement system (OQMS).
5. Provide oil mass measurement through direct and indirect dynamic measurement methods.
6. Describe major and supplementary measurement methods, oil quality measurement system equipment.
7. What are the main and additional parameters controlled in the operation process of oil quality measurement system for indirect dynamic measurements?
8. What are the main and additional parameters controlled in the operation process of oil quality measurement system for direct dynamic measurements?
9. Describe the method of oil mass determination method in pipelines.
10. What are the basic and additional measurement errors?
11. What is commercial gas metering station intended for? Describe its structure.
12. Explain the structure of commercial gas metering station.

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