RECENT DEVELOPMENTS IN SONIC PIPELINE INTERFACE DETECTORS

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ABSTRACT

A sound velocity sensor is described as a means for detecting interfaces between different hydrocarbons in products and crude oil pipelines. Temperature and pressure influences are described as systematic error sources that are amenable to automatic compensation by a microprocessor. The utility of the sonic technique is assessed for detecting difficult interfaces between hydrocarbons of similar API gravities and for those interfaces where substantially different gravities prevail. A new development involving a combination sonic interface detector and sonic flowmeter is also discussed.

INTRODUCTION

During the past decade, sonic (ultrasonic) instruments have emerged in various forms as viable alternatives to some of the other more familiar process measuring instruments. While much of the publicity in trade journals has been devoted to sonic flowmeters and, to a lesser extent, sonic level sensors, the sonic pipeline interface detector has been gaining recognition in the petroleum industry. Today, there are several hundred instruments already in service worldwide. This paper is essentially a review of the salient features of the sonic interface detector and a status report on this comparatively new technology.

The sonic interface detector was initially developed for pipeline service as an outgrowth of an oceanographic instrument which, during the 1960's, was used to measure sound velocity and other physical properties in deep-sea research. Engineers then adopted this technology and produced the first sonic interface detector for service in products pipelines in 1970.[1] There were performance limitations in the early equipment which lead to improvements in both transducer and circuit design. Eventually microprocessors were incorporated into the instrument in order to achieve better control of the variables and, hence, more stable and reliable performance.

OPERATING PRINCIPLE

Sonic interface detectors operate by precisely measuring the velocity at which ultrasonic pulses travel over a liquid path of known dimension. Sound velocity is a unique physical property of materials, as are density and viscosity. Sound velocity "c" is related to the square root of adiabatic bulk modulus "B" divided by density "ρ", as follows:

$$c = (B/\rho)^{\frac{1}{2}}$$

This equation indicates perhaps why sonic interface detectors did not achieve wider acceptance when first introduced, namely, that they measure sound velocity and not gravity in degrees API.

Fortunately, and almost coincidentally, there is a general relationship between specific gravity and sound velocity for petroleum products which is shown in Fig. 1. Specific gravity expressed in specific gravity units, is plotted on the vertical axis versus sound velocity, expressed in meters per second, on the horizontal axis. It can be seen that the relationship between specific gravity and sound velocity is approximately linear. This linearity extends beyond the limits of this graph from ethane-propane mixtures at the low end to crude oils at the high end. The scatter of data points indicated in Figure 1 is not merely experimental error, but reflects the fact that the relationship between specific gravity and sound velocity is a function of chemical structure. As the ratios of aliphatic to aromatic hydrocarbons, of saturated to unsaturated hydrocarbons, of additives and impurities vary, then so too the relationship between specific gravity and sound velocity varies. As a result there is a considerable scatter of points, especially among gasolines and, beyond the limits of this graph, among crude oils. This scatter of points is useful in applying sonic interface detectors to monitoring products of virtually the same specific gravity.

Each product flowing through a pipeline can be represented by a range of sound velocities reflecting the variability in the composition of that liquid from day to day, as indicated in Fig. 2. The operating range of pipeline interface detectors can be adjusted as to zero and span to cover any desired group of products for which interfaces must be monitored. For example, as shown in Fig. 2, if one wishes to measure interfaces between gasoline, naphtha, kerosene and No. 2 fuel oil, the sonic interface detector could be set with a span of 300 meters per second, that is, from 1100 meters per second to 1400 meters per second.

Such a span setting is reflected in Fig. 3, a strip chart recording in which "time" is recorded along the horizontal and "sound velocity" along the vertical. It shows the actual interfaces between No. 2 fuel oil, kerosene, and regular gasoline flowing in sequence in a pipeline. The separation between two major vertical division lines represents a 2-min time interval.

Fig. 4 shows a similar interface detector chart recording but with the span reduced to only 20 meters per second. By a suitable span reduction it is possible to see, as shown in this figure, the interface between a low lead regular gasoline (at 58.4^{o} API) and a premium gasoline (at 58.5^{o} API) as a change of output equivalent to over 50% of full scale.

TEMPERATURE AND PRESSURE INFLUENCES

Unfortunately, sound velocity is not only a function of the composition of the material flowing through the pipeline, but also of temperature and pressure. Fig. 5 shows typical relationships between sound velocity and temperature for a kerosene and a regular gasoline. The relationships are linear with a negative slope, and this slope varies from about 3 or 4 meters per second per degree Celsius for crude oils to as high as 6-10 meters per second per degree Celsius for liquefied petroleum gases. Similar curves can be shown for sound velocity versus pressure although the influence of pressure on sound velocity is comparatively small, ranging from approximately 2 to 3 meters per second per 100 psi for crude oil to greater than 10 meters per second per 100 psi in liquefied petroleum gases. When a sonic interface detector is adjusted to a very narrow span of sound velocities in order to see gasoline-to-gasoline interfaces, the device must also correct for temperature and pressure variations to some preselected standard condition, normally 60^{o}F and 0 psig, to prevent the device from mistaking a temperature or pressure change for an actual product interface. This same kind of reasoning would apply to densitometers. That is, in order to make a densitometer read with sufficient sensitivity in order to have a high probability of reading the difference between leaded and non-leaded gasolines, one would also have to measure temperature and pressure and to correct the specific gravity to preselected standard conditions. In other words, the need for temperature and pressure compensation is not unique to sonic interface detectors.

The sonic interface detectors tested in 1970 did not have temperature and pressure compensation and, for that reason, their usefulness was limited. When temperature and pressure compensation were added, the pipeline interface detector had evolved into the form shown in Fig. 6. Mounted on the flange at the left are sound velocity, temperature and pressure transducers. The pressure transducer connects to a hole in the flange, which cannot readily be seen in the figure. Located in the large NEMA 7 explosion-proof enclosure is the transmitter. The smaller enclosure at the right containing the zero and span dials is the receiver which is usually located remotely in a control room. Outputs for chart recording and for supervisory control are provided either by cable or telemetry.

HARDWARE STATUS

In 1972, these temperature-and pressure-compensated devices were reported in published literature as capable of monitoring gasoline interfaces.[2] One would think that by this time the sonic interface detector would be fully commercial and without significant additional problems.

However, this was not quite the case. The early sound velocity probes were designed to withstand pressures of several thousand pounds per square inch but did not take into account pressure transients which occur frequently in pipelines, much like water hammer in home plumbing. These transients destroyed early sound velocity transducers with regularity, and the design had to be modified to withstand these pressure transients. The temperature sensing devices were platinum resistance elements, some of which turned out to be sensitive to the vibrations encountered in pipelines. It was necessary to do a great deal of work to find RTD elements which could withstand these vibrations. The pressure sensing elements were initially of a Bourdon tube-potentiometer design involving a wiper moving along a conductive core as the Bourdon tube expanded with pressure. The nature and frequency of pressure fluctuations in many pipelines wore out the conductive core of these early pressure transducers in an unacceptably short period of time, and as recently as 5 years ago a solid state type of pressure transducer had to be substituted. With these changes, it was finally possible to achieve the low maintenance requirements predicted in the early published articles.

As previously stated, the early transducers were normally mounted in flanges in the pipeline as indicated in the sketch, Fig. 7, and the picture of a typical field installation, Fig. 8.

SENSORS FOR PIGGED LINES

Referring to Fig. 9, early development work showed that the transducers could be mounted in the recessed mode, shown at left, in the case of product pipelines without significant delay in response time. This, of course, would permit pigging of the line. For heavy crude oils, however, mounting as shown at the right, with the transducers protruding into the pipeline, was found to be necessary for satisfactory response time.

In 1974, one of MAPCO's customers developed a probe retractor for use with sonic pipeline interface detectors. Fig. 10 is a sketch indicating a current commercial version of this probe retractor which is only a slight variation of the original design. The transducers may be cranked in or out of the pipeline through a full bore valve permitting installation by hot tap techniques and permitting removal for inspection and possible maintenance without shutting down the pipeline. At the present time, by far the greatest percentage of sonic pipeline interface detectors are being installed mounted in probe retractors.

Fig. 11 shows such a probe retractor in use in one of the pumping stations of a well-known pipeline.

CIRCUIT IMPROVEMENTS

In early 1977, re-engineered electronics were introduced employing a microprocessor and taking advantage of the rapid advances in available electronics hardware. The electronics consist basically of 3 printed circuit cards color-keyed for easy identification, per Fig. 12.

To facilitate maintenance, if and when a problem occurs, the printed circuit cards are of the plug-in type and can thus be replaced in a matter of seconds.

Fig. 13 shows 1 of the 3 printed circuit cards, namely the one containing the microprocessor. Instead of applying the temperature and pressure compensation by analog circuitry as in previous generations, the microprocessor actually calculates the temperature-and pressure-compensated sound velocity, greatly reducing the potential for long term analog drift. Moreover, the device is taught to reject unwanted interruptions by RF noise or bubbles. Among other things, this has made it possible to locate the transmitter greater distances from the sensing transducers, permitting the use in many cases of less expensive, more convenient NEMA 4 transmitter enclosures instead of explosion-proof. Greater resistance to extremes of high and low ambient temperatures was also provided. In this illustration, it can be seen that 4 LED's (light emitting diodes) are provided on the leading edge of the card at the upper right-hand side of Fig. 3, which act as status lights. These LED's show whether various parts of the electronics circuit are in proper operation and facilitate troubleshooting, if and when problems occur. It was seen that making sonic pipeline interface detectors easier to maintain and more resistant to temperature extremes was absolutely necessary in view of the fact that increasing numbers of these devices were being shipped to remote locations such as Indonesia, Iran, Peru and Nigeria.

SONIC FLOW METERING

It was mentioned at the beginning of this presentation that sonic pipeline interface detectors are close relatives electronically to sonic flowmeters. The operating concept of a sonic flowmeter is shown in Fig. 14 in which ultrasonic pulses pass across the pipeline alternately from one transducer to the other at an angle to the axis of flow.

Referring to Fig. 15, the velocity at which ultrasonic pulses travel from transducer A to transducer B is the sum of the sound velocity characteristic of the liquid in the pipeline <u>plus</u> a vectored component of the velocity at which the liquid is traveling through the pipeline. Similarly, the velocity at which ultrasonic pulses travel from transducer B to transducer A is the sum of this same sound velocity characteristic of the liquid in the pipeline <u>minus</u> the vectored component due to the velocity of the liquid traveling in the pipeline. Subtracting the B to A velocity from the A to B velocity, the sound velocity characteristic of the liquid in the pipeline subtracts out from itself and the remainder equals twice the vectored component due to fluid flow in the pipeline. This is the manner in which a sonic flowmeter works. However, if the A to B and B to A velocities are added, it is the flow velocity effect which subtracts out from itself and the sound velocity characteristic of the liquid in the pipeline which is additive to itself. Then, the sum is a direct measure of the composition of the liquid in the pipeline, independent of the flow rate. It can be seen that all one would have to do to convert a sonic flowmeter into a pipeline interface detector is to add temperature and pressure compensation.

Such a device is represented in Fig. 16. Referring to the two electrical heads protruding directly out of the picture toward the viewer, the one at right serves the pressure transducer and the one at left serves the temperature transducer.

Fig. 17 is another view of a combined flowmeter/interface detector flowtube, along with a NEMA 4 transmitter enclosure.

The first combined flowmeter/interface detector was put into test in the Conway, Kansas pumping station of the Mid-America Pipeline System in 1977. Following a successful test program, combined flowmeter/interface detectors are now in service in Europe and the United States.

As a matter of interest, the flowmeter portion of this device was tested in series with a duplicate sonic flowmeter and a turbine meter. Comparison of 24-hr totalized flows recorded for each of the 3 flowmeters indicated a maximum difference of ± 0.33% over a 15 day period. During the same period the standard deviation of the 24-hr totalized flow was within ± 0.20%. The liquid being measured was primarily propane.

While a complete discussion of sonic flowmeters is beyond the scope of this paper, it would be useful to point out one important characteristic, that of the meter factor dependence on Reynolds number. The Reynolds number (Re) is dependent on pipe diameter (D), flow velocity (V) and liquid kinematic viscosity (ν) according to the relationship:

$$Re = \frac{DV}{\nu}$$

Fig. 18 illustrates the relative change in meter factor that accompanies changes in Reynolds number under conditions of fully developed turbulent flow. The dashed lines are theoretical values while the solid lines are the result of prover calibrations. As indicated, the non-linearity error is non-existent at very high Reynolds numbers, i.e., above 10 million for even the largest diameter pipes. That explains the relatively good performance of the sonic flowmeter during tests by MAPCO on a 6-in. propane line where the Reynolds numbers ranged from 1.6 to 4.1 million. Referring to Fig. 18, there is no non-linearity error so the error reported for the 6-in propane meters was entirely repeatability error. It is also apparent from the illustration that the relative meter factor may change by several percent if the Reynolds numbers encompass values in the 10,000-200,000 range, a situation that may occur when the liquid viscosity is high as it would be for heavy hydrocarbons such as crude oil or heavy fuel oils. It is also apparent from the equation that the Reynolds number will diminish as the pipe diameter or flow velocity is reduced. A more complete discussion on sonic flowmeters is available in another paper.[3]

In summary, I have discussed developments in the sonic pipeline interface detector, starting with its early years, during which several technical developments were necessary to its very commercial survival, and bringing you up to the present day, in which recent developments are broadening its applicability.

References:

(1) Zacharias, E. M., Jr., "The Sonic Interface Detector Meets Field Tests in Pipelining", Oil and Gas Journal, Vol. 68, No. 27: p. 96 (1970)

(2) Zacharias, E. M., Jr., "Sonic Detectors See Gasoline Interfaces", Oil and Gas Journal, Vol. 70, No. 34: p. 79-81 (1972)

(3) Ord, R., Jr., "Application of the Sonic Flowmeter", paper delivered at the Pipeline Cybernetics Seminar, American Petroleum Institute on April 7, 1976 (reprints available from MAPCO Inc., Process Controls Division, 1800 South Baltimore, Tulsa, OK 74119).

Acknowledgement:

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Specific gravity vs. sound velocity

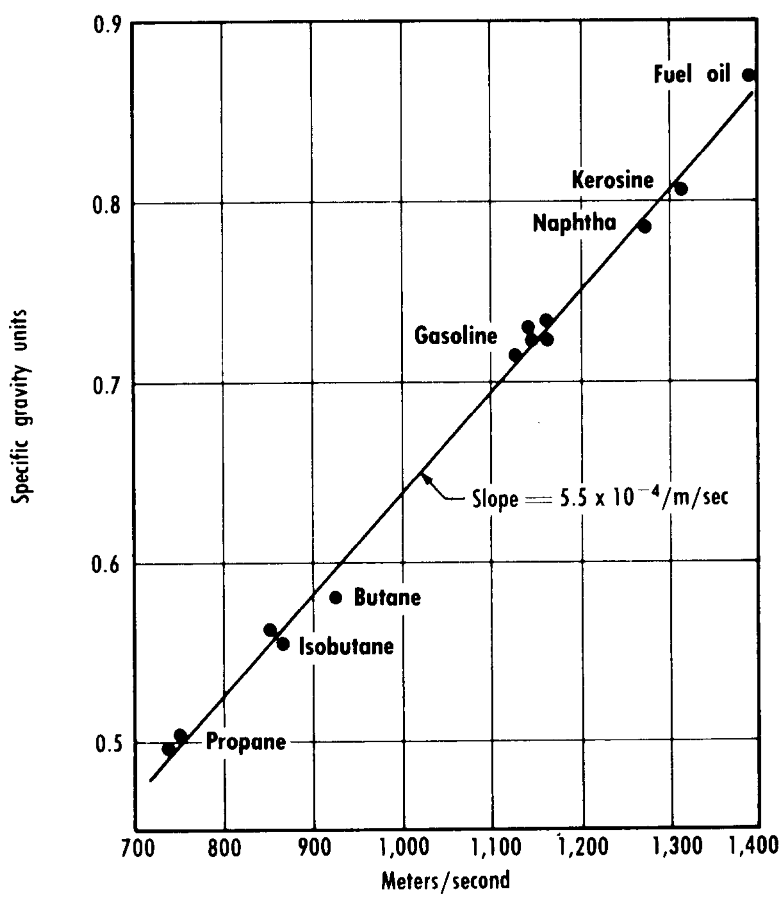

FIGURE 1

Receiver zero and span controls

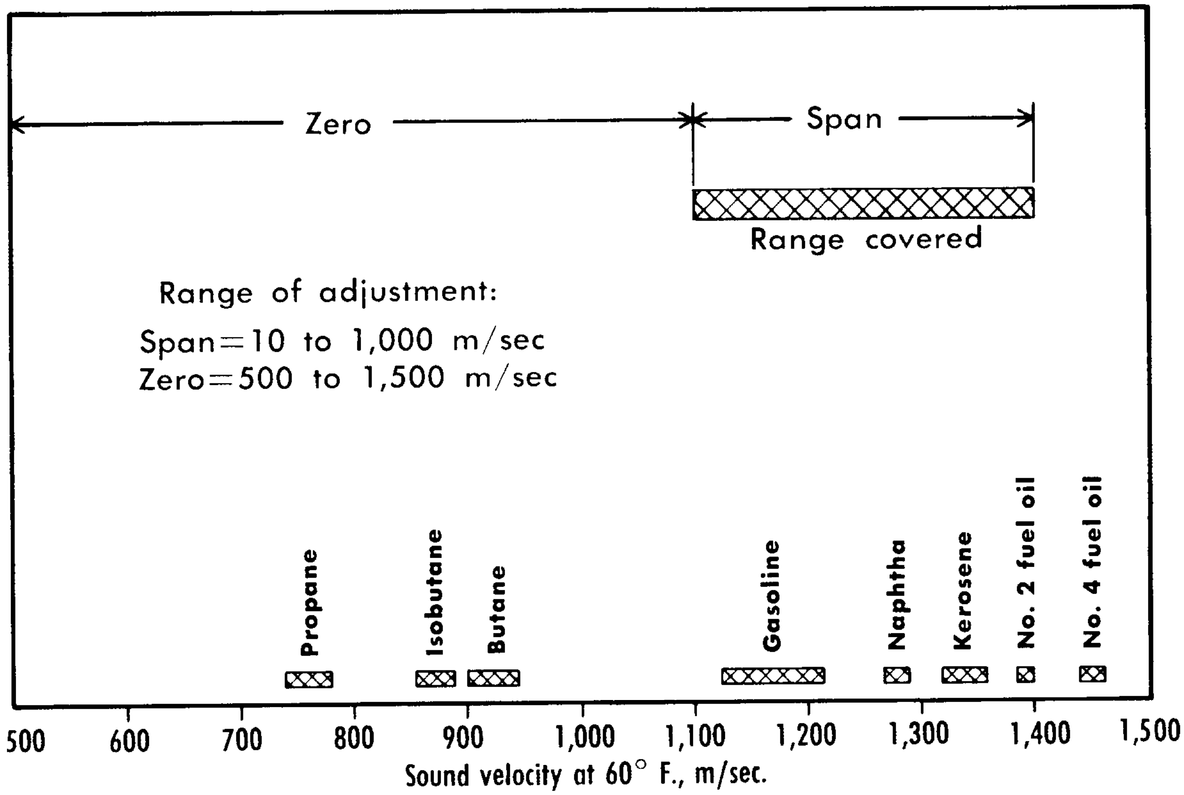

FIGURE 2

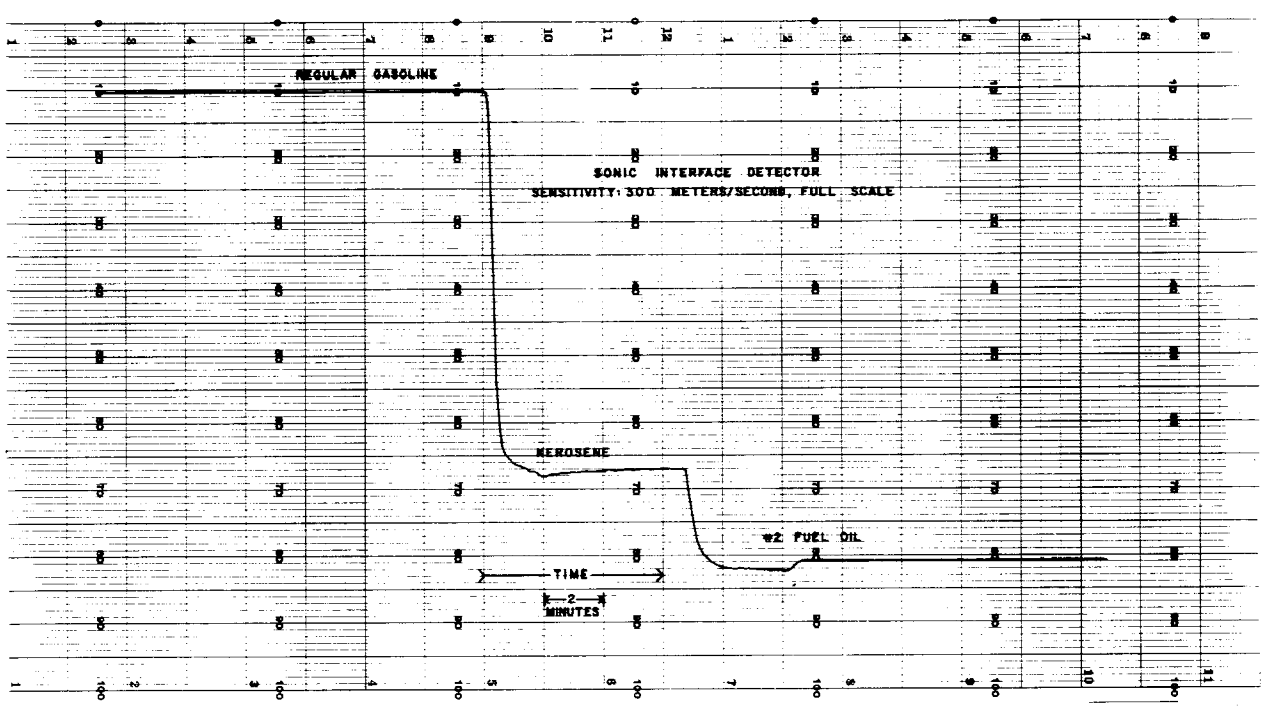

FIGURE 3

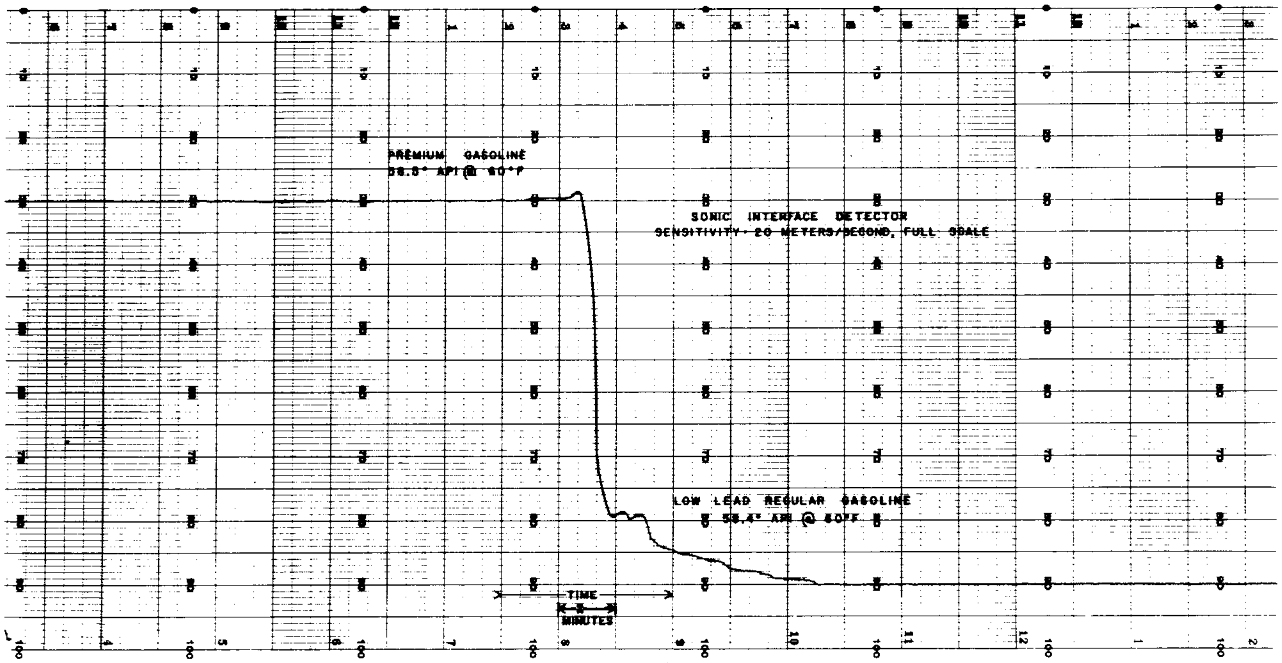

FIGURE 4

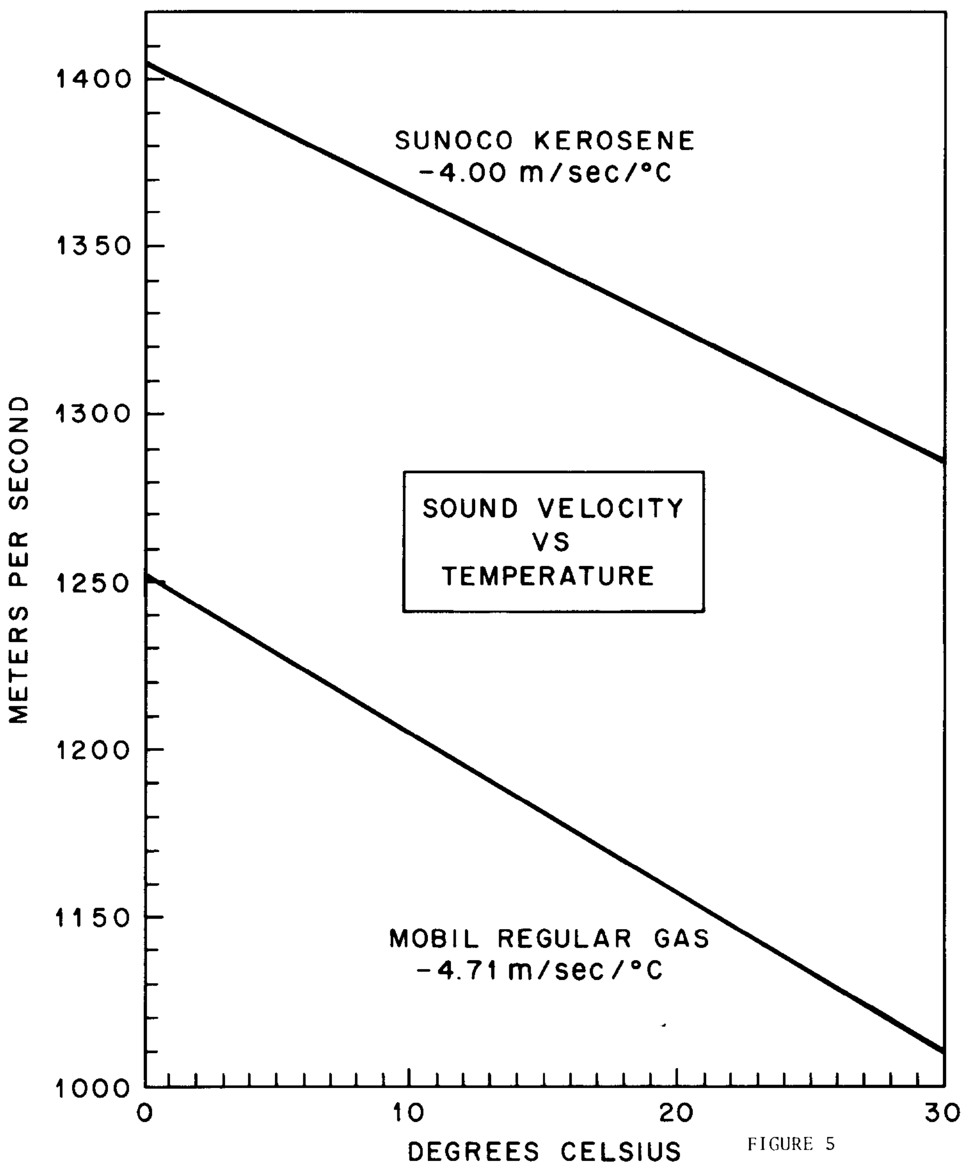

FIGURE 5

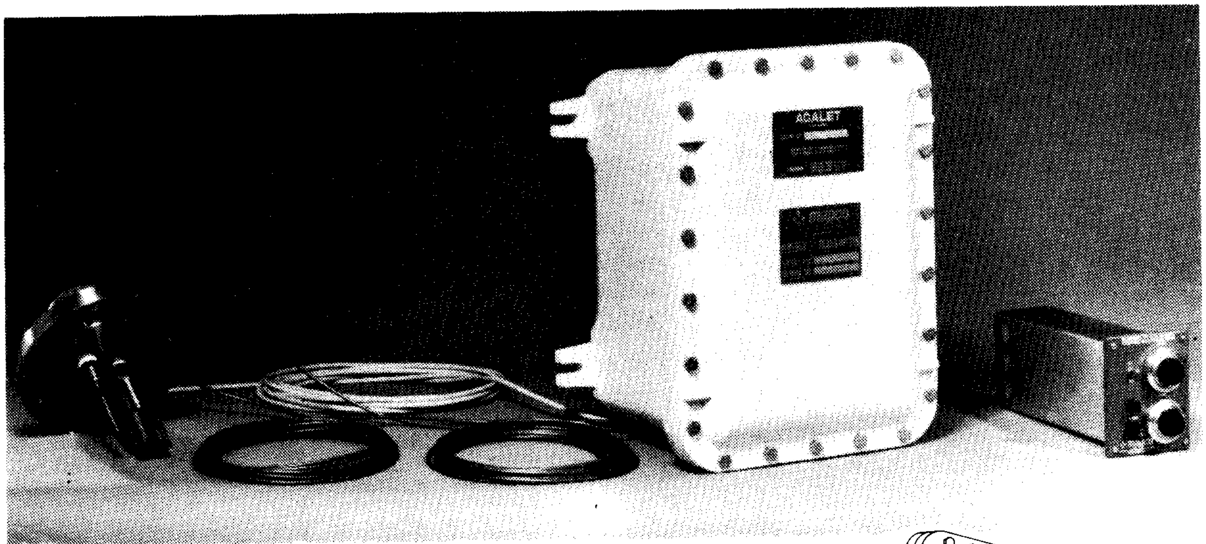

FIGURE 6

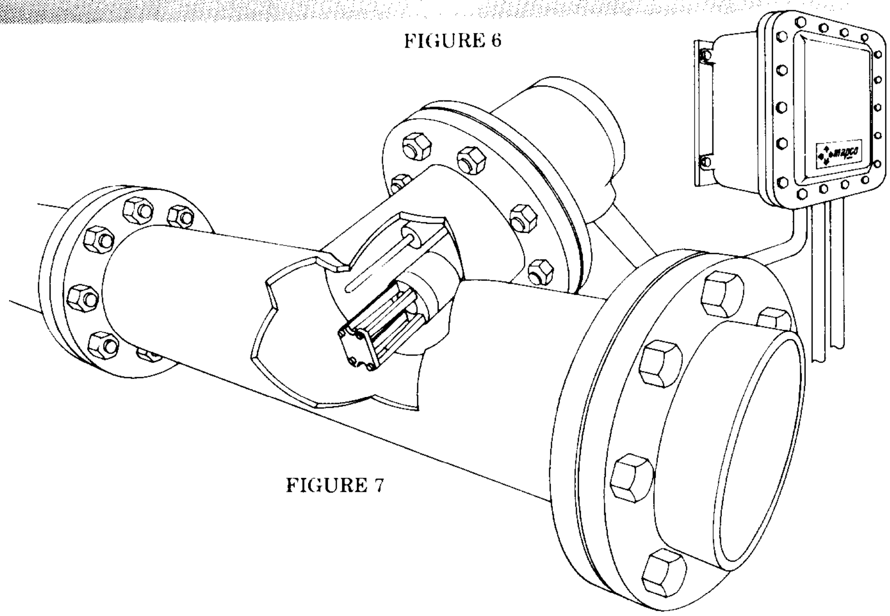

FIGURE 7

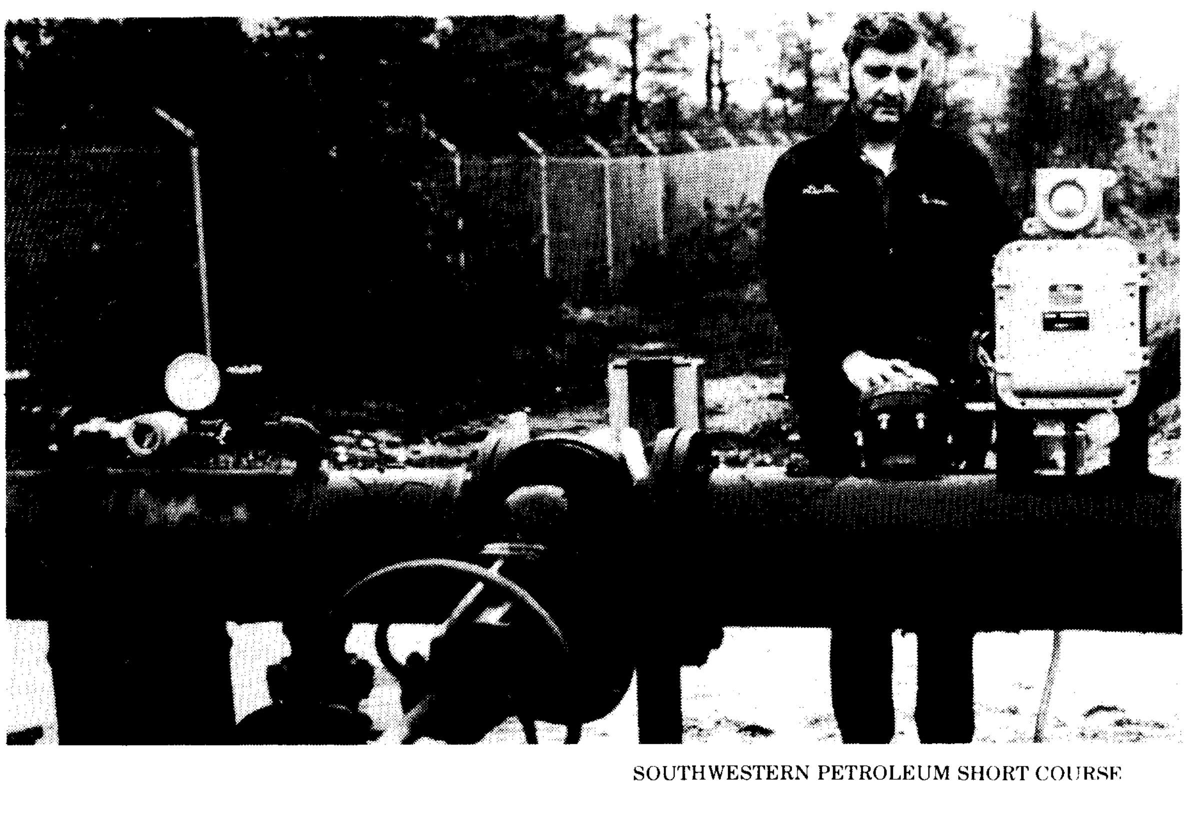

FIGURE 8

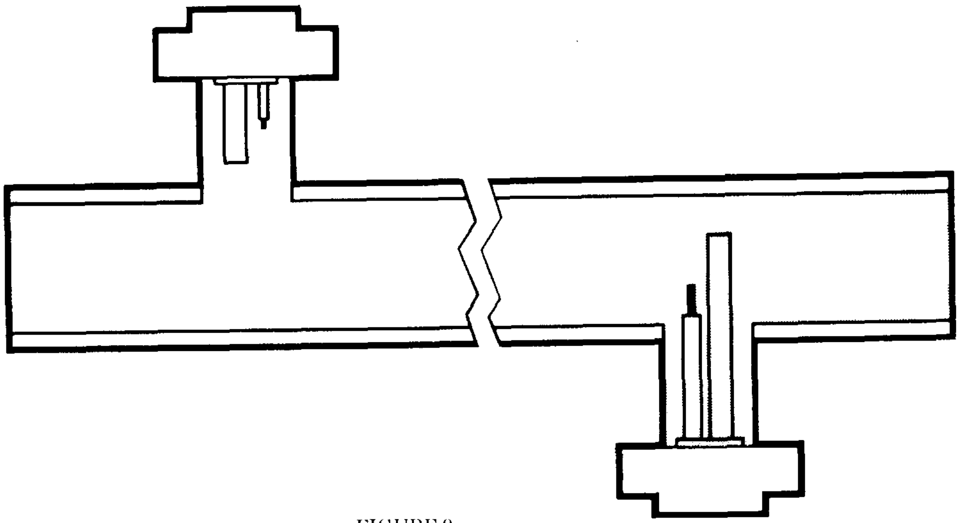

FIGURE 9

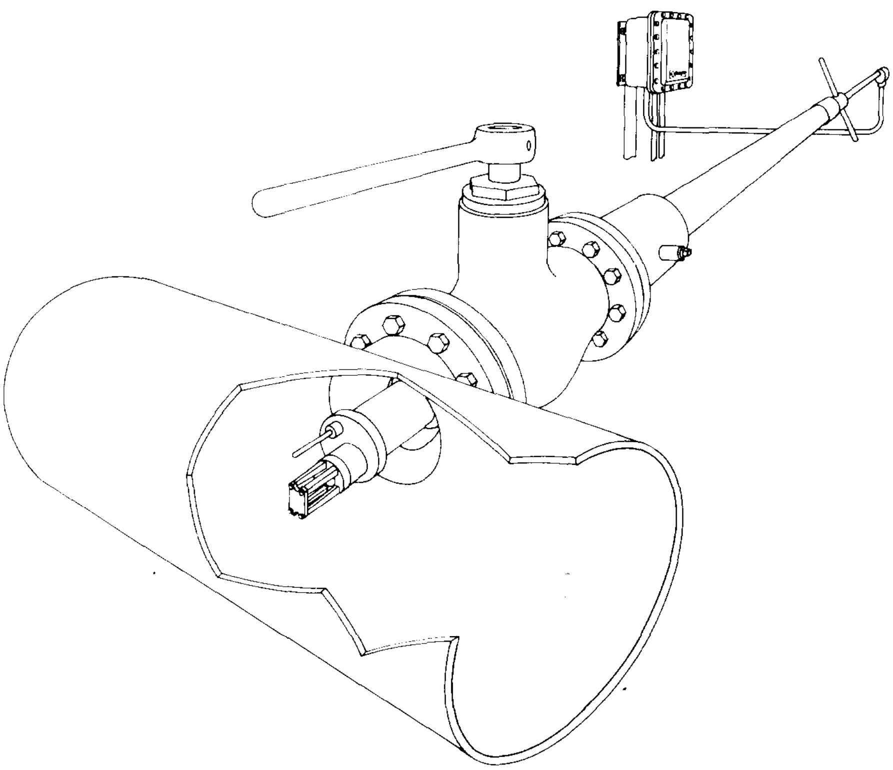

FIGURE 10

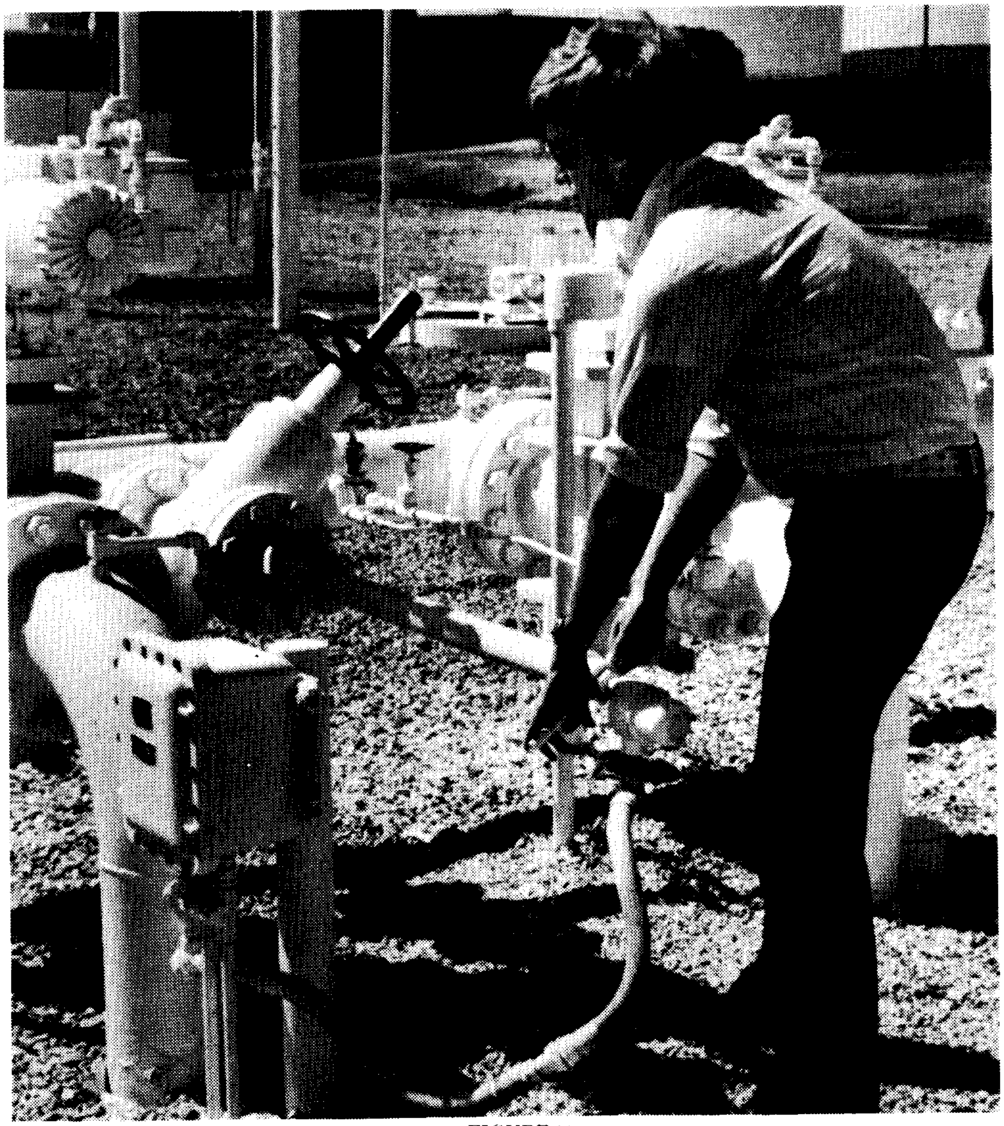

FIGURE 11

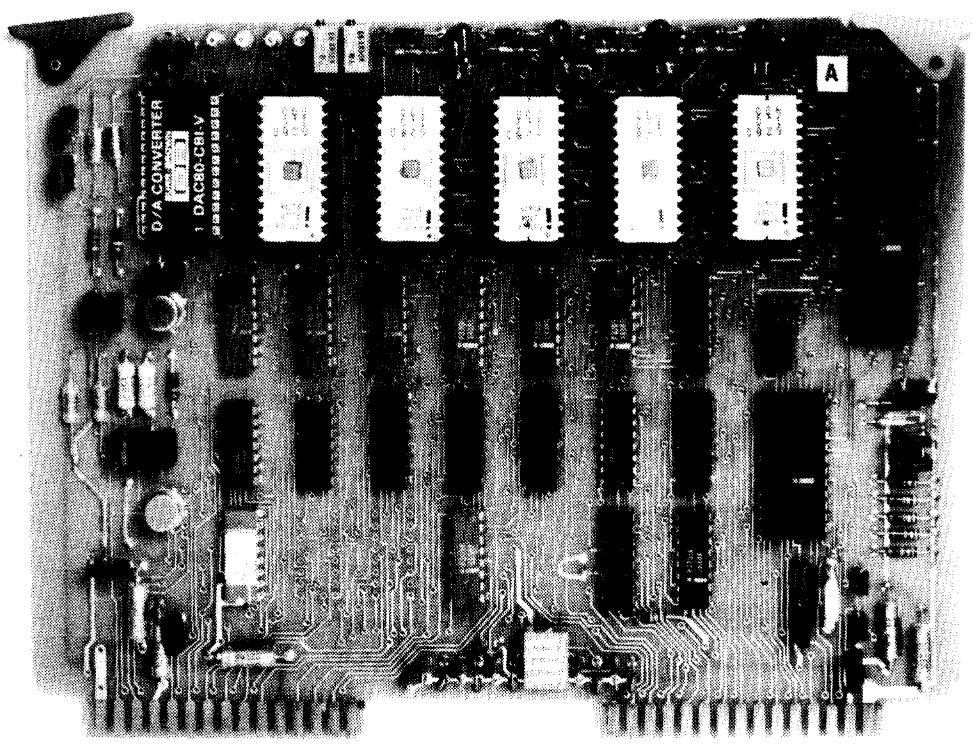

FIGURE 13

(see figure 12 on following page)

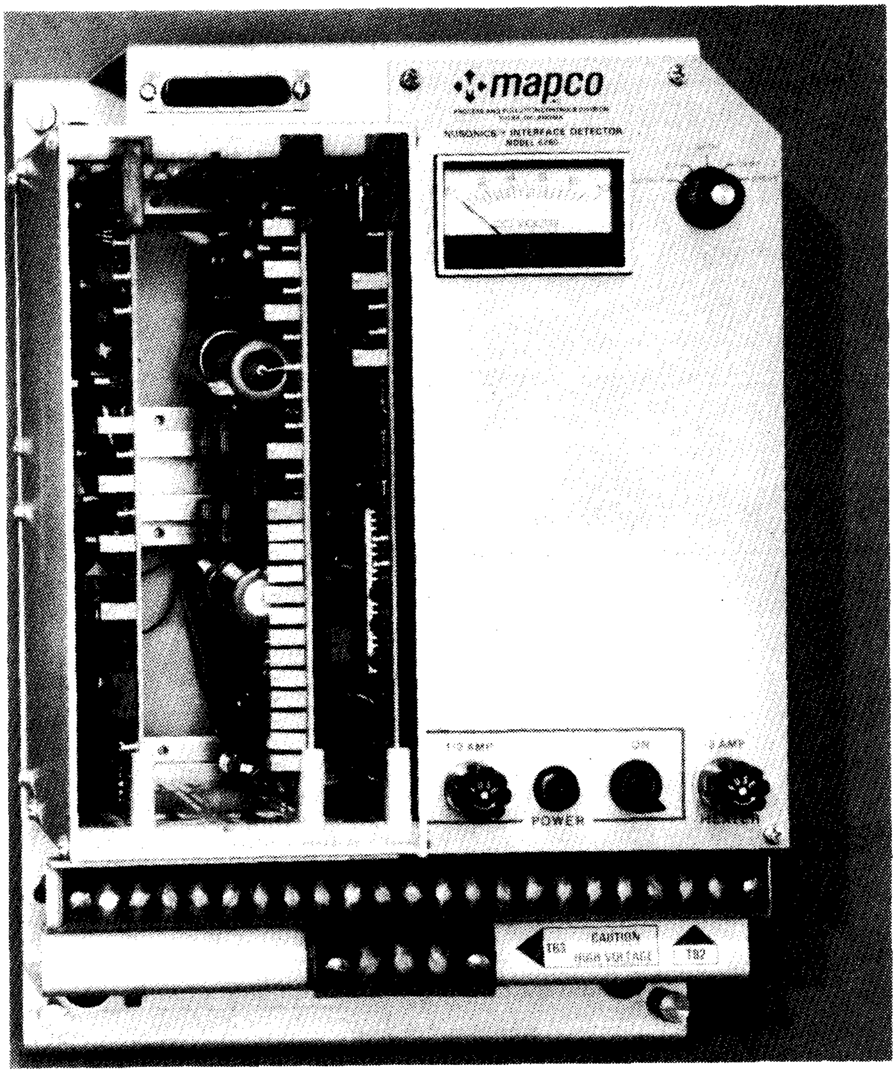

FIGURE 12

(see figure 13 on preceeding page)

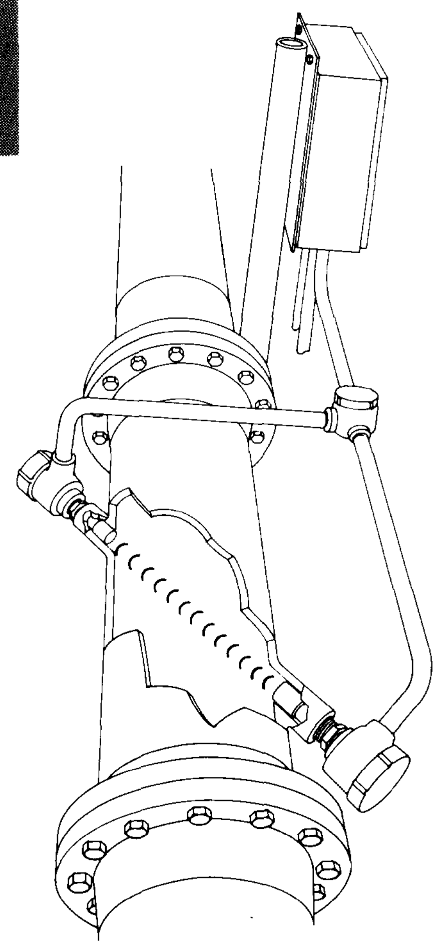

FIGURE 14

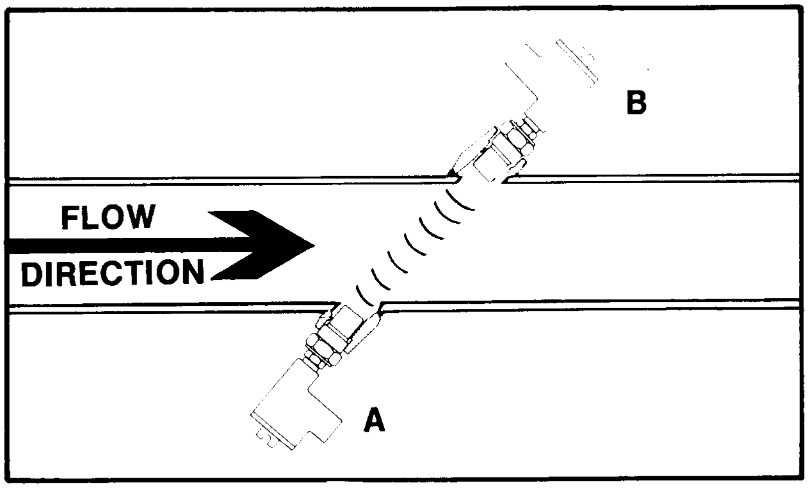

FIGURE 15

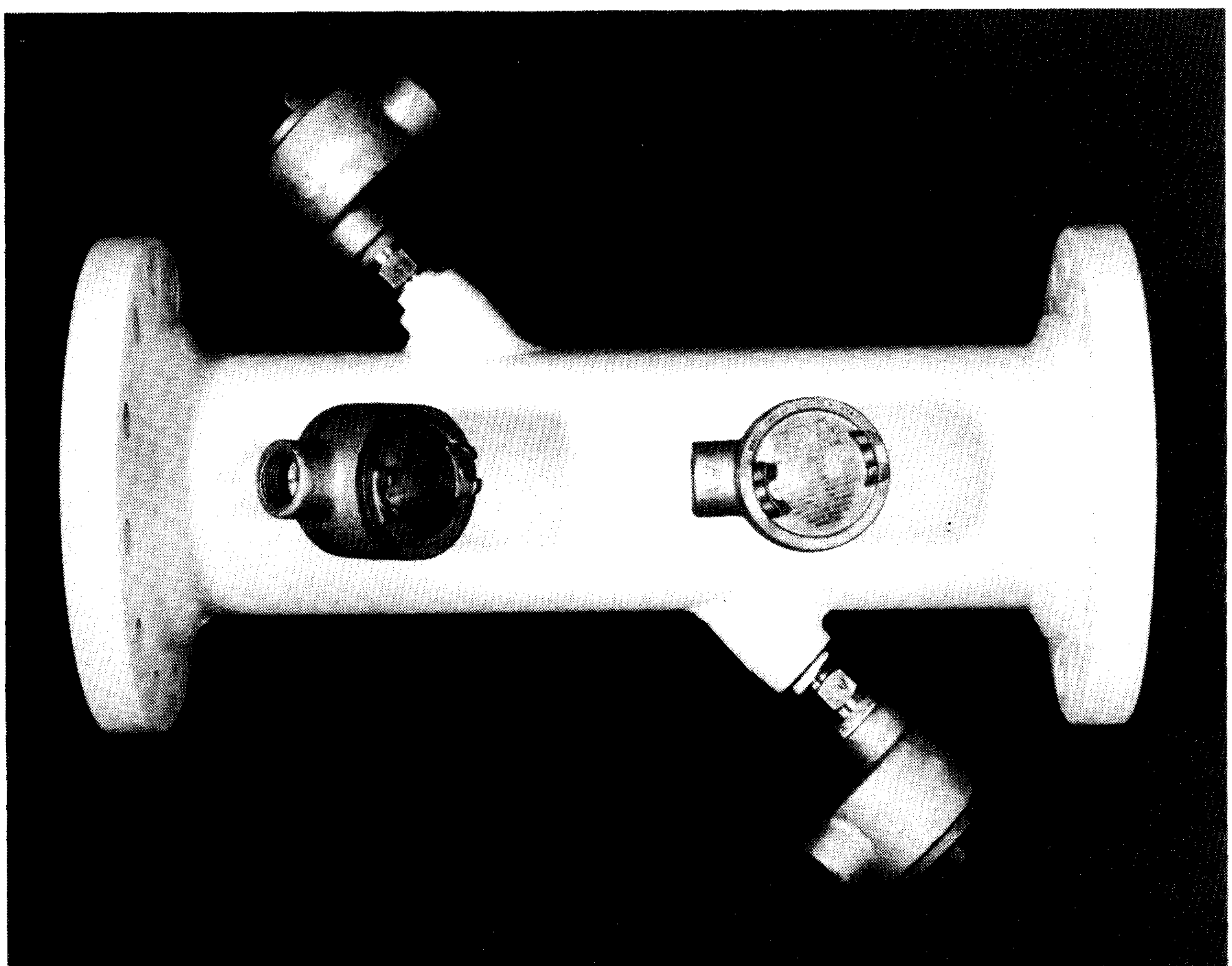

FIGURE 16

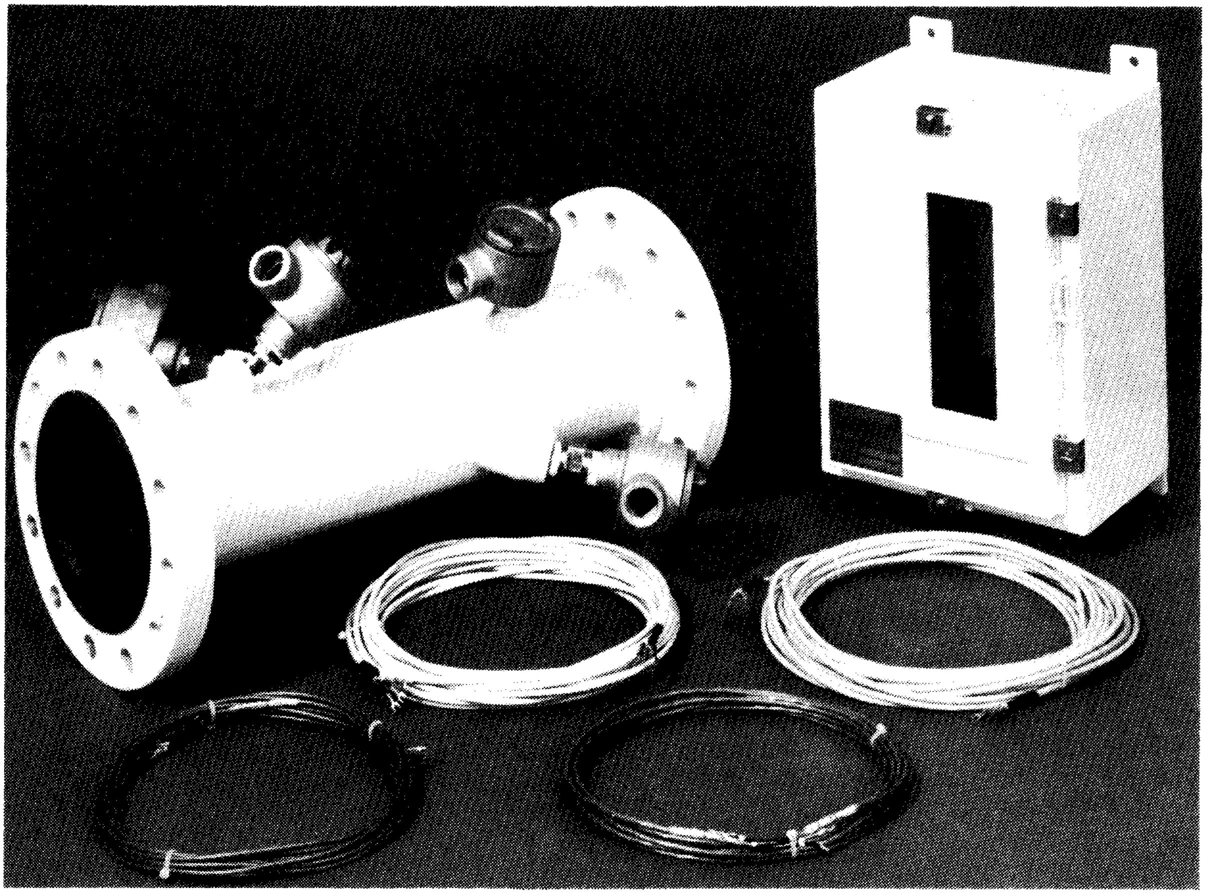

FIGURE 17

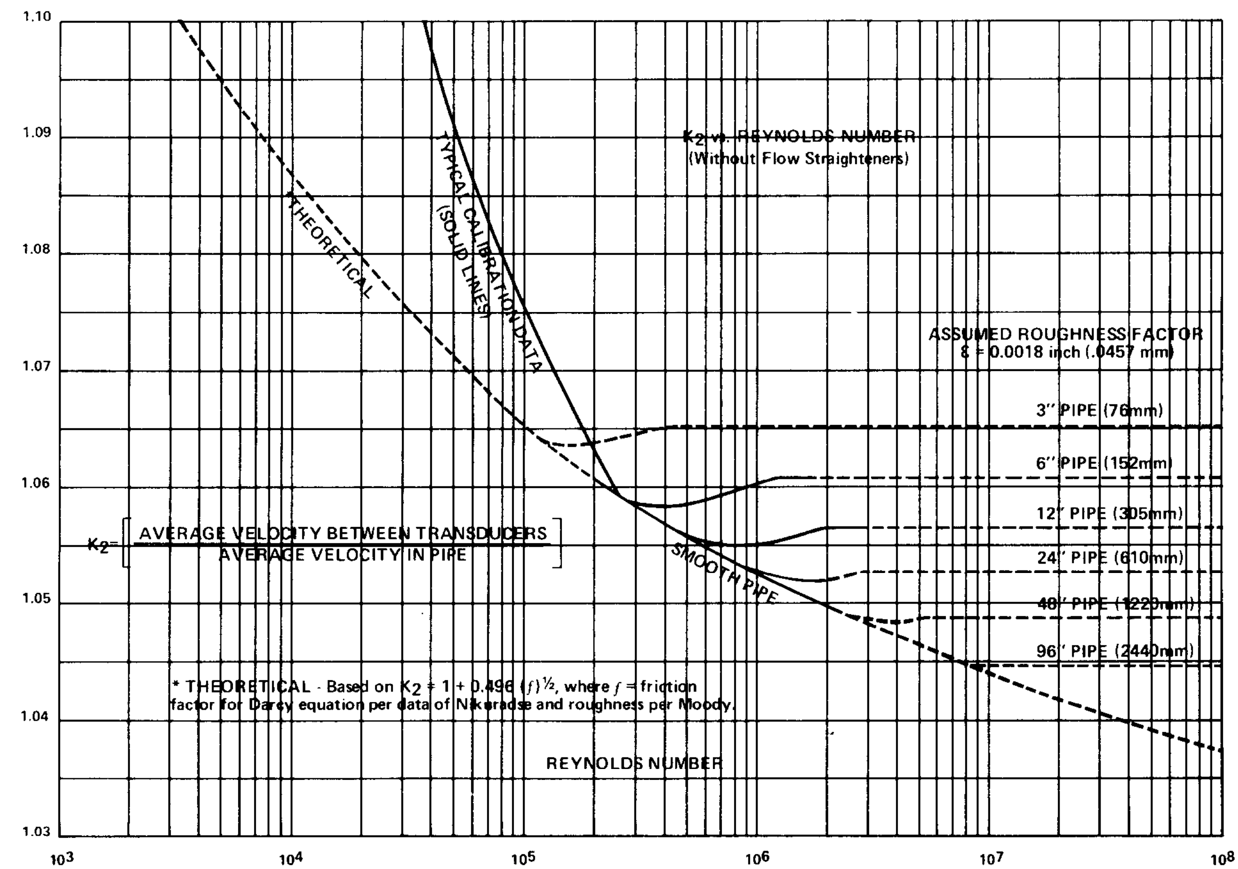

FIGURE 18