Instrumentation and Controls for Solution-Mined Underground Storage Systems

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ABSTRACT

Underground storage systems have operational characteristics and requirements that differ substantially from those normally encountered by an instrumentation and controls design engineer. It is necessary to have a good basic understanding of these special characteristics, the nature of the limiting parameters and anticipated operating problems to develop an instrument and controls design that will adequately protect the overall storage system. Pressure, flow control, measurement and material balance are the principal control areas. This paper is not intended as a comprehensive design guide, but rather as a basic statement of operating principles for solution cavern underground storage systems as they relate to that field. One version of the instrumentation and controls system that might be used in a propane import terminal supported by solution cavern underground storage is included in the paper as an example.

INTRODUCTION

Underground solution mined storage systems and their surface support facilities have become increasingly more complex with the passage of time. When this storage method was first developed and used, the operation, control and surveillance of the system was almost entirely manual. These early systems generally consisted of a few small-capacity storage caverns, injection and recovery rates were very low, the variety of products stored was very limited, receipts and deliveries were generally from/to trucks or rail tank cars and almost all of the system was within sight or hearing of the operator. Tank strappings were used for measurement. In most instances, operation cycles were intermittent, sometimes during daylight hours only, fill took place during the summer and withdrawal during the winter months. Wellhead safety controls were very rudimentary. Environmental constraints, for all practical purposes, were nonexistent. Solution mining procedures for development of storage caverns were by trial and error. In most instances the storage operator did not know the cavern configuration, and the storage capacity could not be verified until the cavern was actually filled. Some operators did not maintain protective blankets below the final cemented casing seat or even hydrostatically test the cavern before using it.

After the first few years, and as the number of sites increased, considerably more sophistication in design, construction, solution mining techniques, instrumentation and controls and operating techniques took place. To a large degree, this was due to major oil companies entering the field who had the engineering support capability that could be directed to refinements in design and to carry our special studies related to various aspects of the storage system. Several service companies developed special tools, and equipment manufacturers put together "off-the-shelf" items or developed specialized end devices and control systems especially for application in this particular field. One of the most important tools developed was the oriented sonar caliper which is described in greater detail later in this paper.

In recent years a greater variety of products are being stored, the cost of these products is much greater than in the past, the volume stored in individual caverns has increased manyfold, product injection and withdrawal rates have increased greatly, there are many more storage wells at each site, and operations are continuous. Major manufacturing plants use underground storage for surge capacity and are almost completely dependent on such systems to protect themselves from supply interruptions. In some cases, solution mining operations are underway at the site, either for commercial brine production or for enlargement of storage space, at the same time storage operations are being conducted. Many sites handle products in and out by pipeline only. In some instances these pipelines are batching different products on close schedules and are operating at very high flow rates. Environmental constraints are severe, particularly in regard to air quality and brine disposal. Some storage sites are in the vicinity of heavily populated areas and any system upset or accident is given immediate and wide publicity by the news media. Governmental agencies have published regulations in regard to design and operational criteria which must be complied with. These agencies hold public hearings as a preliminary to granting construction and operating permits for underground storage systems and must be convinced they pose no hazard to the public welfare.

STRATEGIC PETROLEUM RESERVE

The Strategic Petroleum Reserve (SPR) plan of the United States is now being implemented. The goal of this program is to have one billion barrels of crude oil in reserve storage by December 1983. A major portion of this reserve will be stored in solution caverns. Many existing solution caverns are being converted to crude oil storage, but more than one-half of the space will be in newly created solution cavern capacity—each new cavern will have a storage capacity of ten million barrels (1.6 million cubic meters). The total Reserve will be in some 95 to 100 solution caverns and several dry mines. One of the basic design parameters is that the Reserve be recoverable within a specified period of time. This time interval could be as short as 150 days; however, the withdrawal period could be lengthened somewhat, depending on the nature of the supply interruption and other measures taken to control consumption rate. Injection of crude oil into existing caverns will take place concurrently with development of new caverns at certain sites. New cavern development will use a construction technique known as Leach/Fill—by carefully controlled procedures, newly created storage space in the upper reaches of the cavern will be filled with crude oil on a continuous or intermittent schedule as the space is produced concurrent with development of storage space below the oil/brine interface. The individual SPR sites receive and deliver crude oil via pipeline at extremely high rates. These pipelines originate at ports of entry of the imported crude oil. Tank farms at these ports receive the crude oil at tanker discharge rates and it is then pumped to underground storage at the design injection rate of each particular site. When the need arises, the crude oil will be withdrawn from underground storage and returned through the same pipeline. When the oil reaches the tank farm it is either pumped into existing crude oil distribution pipeline systems, loaded back in tankers, or distribution is made by a combination of the two. System management control is from a central operations office.

A great deal of data transmission is required between the individual storage sites and the operations office and a very reliable and secure communications system is absolutely essential. Storage sites will be manned and there will be a local control room. Because of the number of individual wellhead control points (in some cases there are as many as four entry boreholes into a single cavern) and variety of other operations underway, it is necessary to have a very extensive instrumentation, control and surveillance system. Automatic shutdown systems on solution cavern wellheads and pumping gear are a vital segment of this system. As an illustration, a single site could have oil injection, brine disposal, and leach/fill operations being conducted concurrently with oil receipts from the pipelines and from a local barge dock as a further complication. There could be as many as ten to twelve sites feeding data into the Central Operations Office.

The Strategic Petroleum Reserve Program is a gigantic undertaking—one that is far more ambitious than any underground storage operation contemplated in the past and is unlikely to ever be equalled in the future. It is not the author's intention to dwell further on this particular program.

PROPANE IMPORT TERMINAL

The intent of this paper is to present an overview of an underground storage system installation that industry might construct, and to set out the various facets of an instrumentation, control and surveillance system adequate to safely operate it with a reasonably-sized staff.

To make this mythical underground storage facility more contemporary, it will be assumed to support a propane import terminal equipped to receive refrigerated propane in tanker cargo lots of approximately 350,000 barrels each. Such a tanker draws somewhat less than 37 feet of water. There are several salt domes along the Texas-Louisiana Gulf Coast reasonably close to water courses having sufficient depth to accommodate such tankers.

Major components of this facility would consist of tanker mooring facilities; a platform on which loading arms, piping, valves, and manifolds could be mounted to take tanker discharges; a measurement system satisfactory to the United States Customs for custody transfer of foreign propane to a domestic buyer; insulated flow lines; shoreside refrigerated storage tanks having sufficient volume and designed such that the tanker can discharge at its full rate; low temperature, low NPSH pumps to move the refrigerated propane through a heater to conventional pipeline pumps and thence into a pipeline connecting the shoreside installation to the underground storage site. At the underground storage site there would be several solution caverns, each equipped with a wellhead and a cased borehole containing the tubing string. The size of the boreholes and tubing and the aggregate volume of the solution caverns is set to meet the anticipated operating requirements of the facility. A variety of pumps, flow lines, valves, manifolds, etc., are provided to get the propane and brine into and out of the storage chambers.

OPERATIONAL ASPECTS

A better perspective of overall operations may be gained by study of the process narrative covering the various system functions that follows. A typical refrigerated tanker carrying 350,000 barrels of propane at −50°F has just moved into position alongside the dock. The various mooring, breasting and spring lines have been run out to shore, the ship has been secured and the engine room "rung" down. The tanker crew stands by the tanker discharge connection, the shoreside operator controls the positioning of the hydraulically actuated loading arm by visual observation and manipulation of radio controls until the end of the arm matches up with the tanker discharge flange. The tanker crew makes up this connection while the shore operator is moving another series of loading arms in position to be connected with the other liquid and vapor discharge connections of the tanker. For the sake of simplicity, assume all shoreside installations have already been cooled down by a secondary piping circuit utilizing the tank-holding refrigeration system and that shoreside tanks have some liquid in them. Custom officials are at the site to approve the ship's papers and manifest, and a third party has witnessed and verified the volume of cargo on the tanker and in the shore tanks prior to discharge. When Customs has cleared the cargo for discharge and the tanker pumps are started up, the refrigerated propane moves to the shoreside tanks and displaces vapors therefrom back to the tanker compartments being discharged, such that there is always an appropriate system pressure balance. It is important to discharge the tanker in the shortest practical time to prevent accumulation of very high demmurage charges.

At this particular site, studies have established the most economical type facility to be refrigerated storage tanks as opposed to making full tanker discharge directly to the underground storage caverns.

The shore tanks provide for surge, which is an important factor, since in every operation it must be assumed that "if anything can go wrong, it will go wrong." This surge capability also allows a smaller diameter connecting pipeline to be used and lower propane injection rates into the storage cavern; thus, smaller boreholes and tubing strings can be used. Pipeline construction costs and borehole drilling costs increase substantially with pipe size. Naturally, it is necessary to have at least one borehole to solution mine the storage chamber; a basic well design might handle up to 5 MBPH and additional boreholes would be drilled and cased as flow rates go up in this increment. Each such cased and equipped borehole costs approximately $850,000, so surge tank capacity can materially reduce investment.

PRODUCT MEASUREMENT ON SURFACE

The measurement procedures and equipment to be used must be approved by Customs. Positive displacement meters and turbine meters with provers are assumed to be satisfactory to them, although it is preferable that shore tank strappings be used, since this approach is the more economical in investment and manpower and is also customary in practices of the trade. It is always important that a third party witness all gauges on the tanker and at the shore tank because of the major volume of expensive product being handled and to avoid controversy with foreign sellers.

It is probably a rather old-fashioned saying, but certainly applicable to this situation, that "you've got to know where you've been to know where you are." *It is important* to establish starting inventories and to keep track of all intermediate movements of liquid and vapor flow to and from the shore tanks. Meter readout in weight measurement units is the preferred way of accounting for the movements of refrigerated propane liquid and vapor. It is simple to convert to any other units of measurement and to standard volumes at temperatures set out in the sales contract. With an opening inventory, accurate measure of all movements in/out of the shore tanks (both vapor and liquid) and a closing inventory, a balance can be proved between the volume of vapor and liquid arriving on the tanker versus the volume leaving on it as compared to change in volumes of vapor and liquid in the shore tanks.

The tanker discharge has now been completed and the above balance has been made. Assuming there are two shoreside refrigerated tanks, it is possible, of course, that one could be gauged off and transferred to the underground storage site while the second is being filled. Assuming a tank has been filled and gauged off (the temperature is approximately −44°F and is being held by an exterior holding refrigeration system), then deep well pumps taking the suction from the refrigerated tank are started up and "boost" the propane through a heater (which raises the temperature from −44°F to approximately 40°F). The heated propane then enters the suction side of the high pressure pipeline pumps at a handling temperature suitable for conventional horizontal split case centrifugal pumps. The heat source could be from exhaust gases of turbine drives on the pipeline pumps supplemented by burners using liquid propane directly from the line. The pipeline pumps discharge to the pipeline connecting the shoreside facilities with the underground storage sites.

There are two design philosophies as to where pipeline pumps should be located. They may all be at shoreside and put out the full volume at sufficient pressure to move propane directly through the pipeline into the solution cavern and displace the brine therefrom to the brine pit. Depending on the distances between the shoreside installation and the underground storage site, it is sometimes more economical to have two sets of pumps—one set to move the propane through a smaller diameter pipeline to the storage site and a second to inject it into the underground storage caverns. It is conceivable propane deliveries from the storage site to the connecting point on a distribution pipeline could be made by utilizing the latter pumps. It is important from an operational standpoint (leak detection by material balance, accounting for volume received at the terminal site, etc.) to have a good measurement system on both ends of the pipeline. It is generally assumed the measurement system at the discharge end of a pipeline is the controlling one insofar as leak detection is concerned. The measurement system at the storage site is also used to account for products moving from storage into the distribution system. A check meter may be used in the shoreside area at the injection point to the pipeline instead of a custody transfer meter. Meters are proven at the storage site and the check meter can be adjusted to read with them. If the variation between the volume passing through the check meter and the volume passing through the custody meter at the storage site is above a preset limit, an alarm is sounded indicating the possibility of a leak in the pipeline. Propane is now at the underground storage site and is being injected into the underground storage cavern.

PRODUCT MEASUREMENT—SUBSURFACE

It is appropriate here to explain the system pressures (see Fig. 1) involved in an underground storage operation utilizing solution caverns. When propane is introduced into the annular space of the borehole (i.e., between the casing and the tubing), it progresses downward toward the storage cavern below the ground surface and displaces brine therefrom through the tubing and surface flow lines to the brine pit. In effect, a differential pressure is created between the two legs of this U-Tube system when .5 sp.gr. propane is in the annular space and 1.2 sp.gr. brine is in the tubing space. In addition, there is pressure created as a result of flow in the annulus and the tubing and in the brine return system. The magnitude of this pressure drop depends on the borehole size, tubing size, and the size of the brine return flow line, and is the direct function of the rate of flow. The pressure reflected on a gauge at the propane side of the storage cavern wellhead is the total of these pressures during flowing conditions and increases progressively as propane moves downward in the storage cavern, reaching a maximum when the cavern is at the fill point. The pressure on the propane side of the wellhead under static (no flow) conditions is, of course, that of the U-tube pressure between the brine and propane column.

An explanation of how the storage cavern is calibrated (strapping table) is also in order. Once it has been solution mined to the required volume, a sonar caliper is run on a wireline from the surface into the storage cavern. This is a rotating miniaturized sound pulse transmitter and receiver which sweeps a horizontal circle. The vertical line followed by the tool starts at the casing seat or at the last point where it contacts any fulcrum. The final fulcrum will set the base point of the vertical strapping line. The signal pulse can be compensated to take into account the density of the media surrounding it. Its minimum range is approximately a four-foot radius and maximum is essentially unlimited, but from a practical standpoint, it is one-half the distance sound can travel in the media within the time period between two sound pulses. The sound wave goes out, contacts the inside face of the solution chamber and bounces back to the receiver. A continuous trace of this signal appears on a cathode ray tube at the surface. The dwell time of the image on the CRT is such that a Polaroid camera can photograph the trace. A north pointing signal shows as a line on this photograph and fixes the orientation of each trace in relation to magnetic North. The depth to each trace is known from the cable footage reading or it can be tied back into a collar locator reading on the casing seat. A series of cross sectional photographs of the solution cavern are made from top to bottom at set intervals (unless some peculiar characteristic of the solution cavern is to be investigated in detail). These cross sections are then arranged in proper order, a planimeter is used to measure the area of each photographed cross section and this information is fed into a computer. The computer takes the cross sectional area of each trace, interpolates between successive ones and gives a readout in barrels. This procedure is repeated from top to bottom of the solution cavern. The resultant chart is the strapping table for that particular cavern. It shows volume in barrels for each successive section and the cumulative volume of the solution cavern. The order of accuracy of this strapping is generally stated as being ±5%, but actual experience indicates the accuracy is better than this. The tool can also be rotated approximately 170° in the vertical plane to look at the bottom and top of the cavern or to define major irregularities in the sidewalls of the cavern.

Once the above strapping table has been produced, and presuming no further salt dissolution takes place in the solution cavern, it can be used as a basis for determining the volume of propane in storage. A separate survey can be run down the tubing to determine the interface between the propane and the salt water in the solution cavern. This survey is quite accurate when based on known reference points "down the hole" (casing seat, tubing collars, etc.). The interface point is located on the strapping table (from the sonar caliper survey), and the volume read off directly. This procedure is the same as reading volumes off tank strapping tables, but it is, of course, reversed: top to bottom instead of

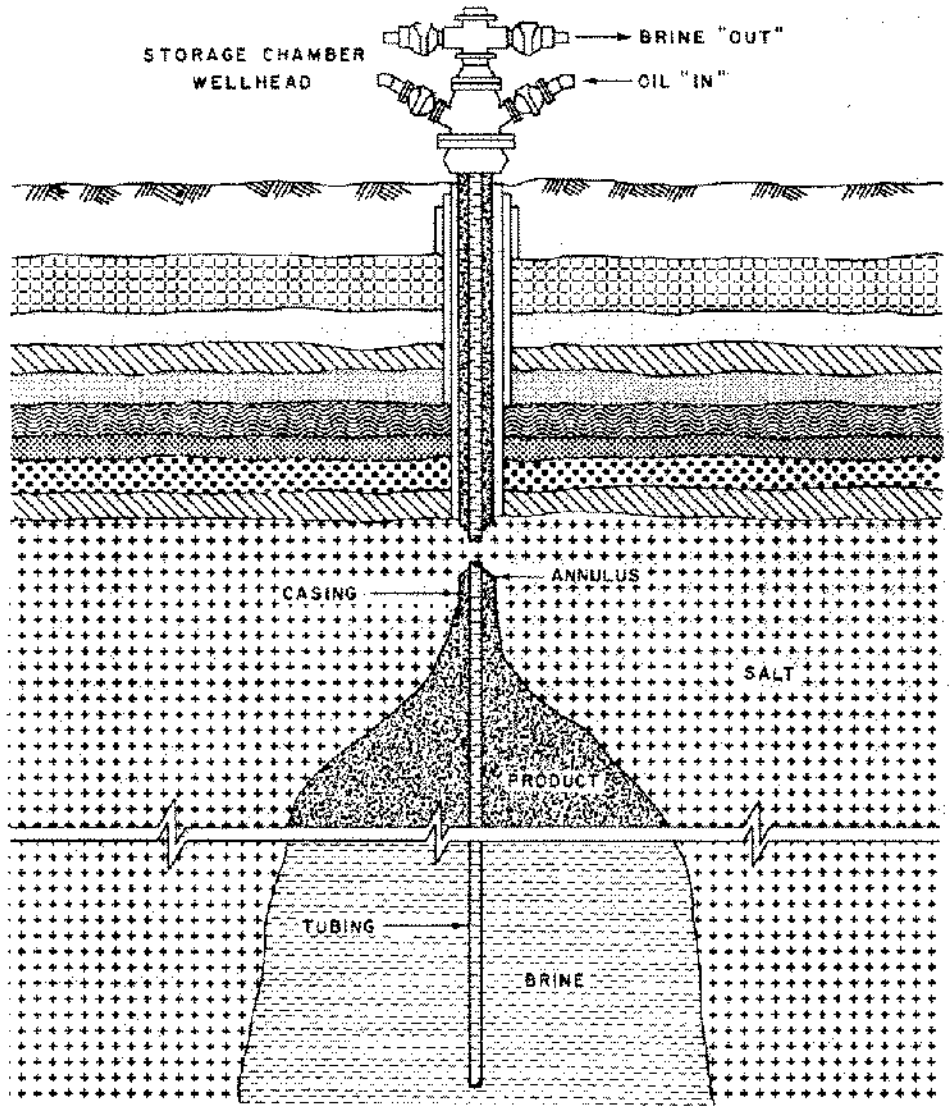

Figure 1. Storage of propane in a solution chamber.

bottom to top. An interface survey is taken periodically. There are other interface locating devices that can be placed on the bottom of the storage cavern. They "look" upward and give a continuous monitoring of the distance from the bottom of the solution cavern to the interface. These types of devices have not been developed to the point that they are particularly reliable. A prototype system is now being tested which is entirely surface mounted (no down hole components). This unit can take continuous interface readings. Once perfected, this type of interface detection system will be an extremely valuable, almost indispensible, instrument for calibration of solution caverns at operating conditions of temperature and pressure, allow optimum control on leach/fill type operations, be tied into a microcomputer for numerous automatic control and operations functions, etc.

Inventory control by comparing results of strapping table and interface survey with the cumulative volume of propane measured by meter into the solution cavern is also possible; however, if less than saturated brine or fresh water is introduced into the storage cavern, more salt will go into solution and strappings will change. Saturated brine taken from the pit at ambient temperatures and put into the solution cavern will take salt into solution until it has reached bottom hole temperature. The latter should have minimal effect but will change the strapping table accuracy over an extended period of time. Strapping tables can be adjusted periodically to correct for these discrepancies but such adjustments must be carefully documented. In most instances, it is better to update the strapping table on a continuous basis in preference to using a strapping table that is obviously out of date. Annual audits quite often are based on the strapping table. From a practical standpoint, an operator should plan to run new sonar caliper surveys at periodic intervals. Scheduling of surveys gets to be quite a problem. The sonar caliper will not penetrate steel, therefore, the tubing string must be removed. The tubing cannot be pulled unless all of the product is out of the storage cavern.

Propane receipts are measured at the underground storage site with unidirectional meters and a prover. The meter skid is manifolded at the outlet so that the full stream from the shoreside installation could go into the underground storage, or to the pipeline connecting it with distribution net, or the stream can be split (a portion going to underground storage and the remainder going to the distribution net).

The next step in the sequence of operations is the actual injection of propane into the storage cavern (Fig. 1). Each cavern borehole is equipped with a wellhead. Propane is injected into the casing side (annulus) of this wellhead and brine is forced out the tubing. Both streams are measured with meters at the wellhead. There will be some normal variation between these two volumes. Propane is much more compressible than brine. A barrel measured into the storage cavern through the propane meter will be compressed down hole because of the weight of the propane column above it. Naturally the propane will displace a volume of brine equivalent to the space the propane occupies at bottom hole pressure and temperature conditions and because of this a "surface barrel" of propane might displace less than one barrel of brine. This variation can be computed and should be supplied to the operator or should be "cranked" into the computer which monitors the variance between the volumes of propane "in" and brine "out" and actuates emergency shutdown systems which will be discussed later in this paper (Fig. 2).

CONTROL INDICATORS—BRINE DISPOSAL WELLS

As has been previously discussed, each barrel of propane pumped into the solution cavern forces out something less than one barrel of brine. The brine then flows through a pipeline to the brine pit. The brine pit is a necessary adjunct in this system to provide surge. This allows the brine disposal rate to be varied somewhat to compensate for factors discussed below. The brine pit is lined with an impervious membrane and is generally of rectangular or square shape. It should be strapped so that the volume in the pit can be read from a gauging device. Pumps take suction from the pit and move brine to the disposal wells. There are several problems involved in the operation of brine disposal pumps that must be taken into account when instrumentation is designed for them. These will be taken up in the next paragraph under brine disposal wells.

Brine disposal wells are drilled into thick sands of high porosity and permeability that generally surround salt domes. A tubing string is run in the cased borehole and "packed off" above the disposal zone screen. The annular space (between casing and tubing) is filled with a neutral medium which has a positive pressure maintained on it to verify "packoff" and casing integrity. There are certain limiting formation pressures that must not be exceeded. The sands have geostatic heads on them about twice that imposed by a column of 1.2 sp. gr. brine. Many unknown formation and reservoir factors, as well as the rate at which brine is injected into them, affect the wellhead pressure required for disposal. Pressures can range from a vacuum all the way up to formation hydrofrac, and flow rates from "fast as you can pump" to zero. Some of these variations are involved every time a brine disposal well is put on the line or occur over such a long interval that reference to permanent records must be used to pin down their magnitude. It cannot be assumed that the only step necessary for brine disposal is to "dump" it down the hole and it will "go away" on a vacuum. Protection must be provided in terms of instrumentation to prevent damage to the disposal pump and driver, overpressuring the formation, to allow an operator at a remote point to be aware at all times of operating conditions at the disposal well, and to record pertinent data for future reference to determine long term effects in the disposal reservoir or to satisfy the rules of various regulatory agencies. A sufficient number of brine disposal wells must be provided to handle all the brine produced during the propane injection phase. It is generally assumed that recovery of such brine for reuse is impractical.

This completes the operation sequence of getting propane into the storage cavern.

CONTROL INDICATORS—STORAGE CAVERNS

Propane should never be allowed to enter the brine tubing string. The tubing is equipped with thread seals to prevent leaks from this source. It is always possible that if tubing is in contact with the casing and thus subject to mechanical abrasion, or, the tubing is damaged while being run into the hole, etc., at some point in time during the filling process propane could enter the tubing—the most critical point, however, is when the storage cavern is near the fill point. Propane is "constrained" within the storage system by the wellhead, casing, and salt envelope of the cavern. Any condition that "lightens" the brine column will cause brine flows to accelerate, since the propane will "expand" to make the system come back into balance. The pressure reduction on the propane side of the system may not be rapid enough for reliable control purposes, particularly if large volumes are in storage or propane injection is in progress. Propane will return to the surface with the brine and be discharged to the atmosphere through the brine/propane separator and flare. If the quantity of propane returning is small, this creates little problem (other than the loss of a valuable product); however, if the quantity is sufficient to "blow" most of the brine out of the tubing, the

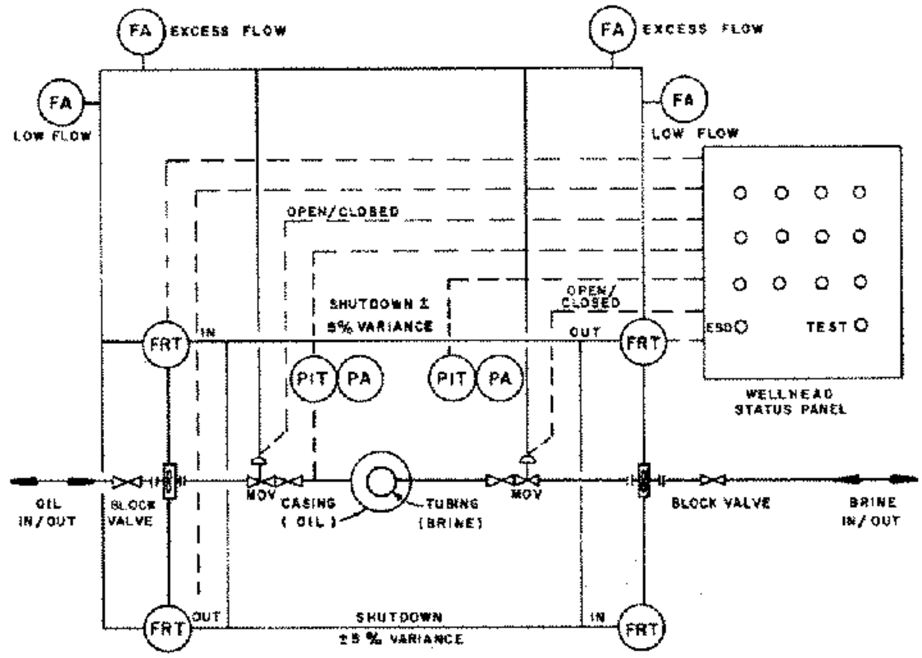

Figure 2. Storage cavern, wellhead instrumentation.

propane will return to the surface at extremely high rates dependent on the propane wellhead pressure at the time of occurrence. This situation can arise if the tubing fails within the propane storage area of the chamber or if the chamber is filled past the end of the tubing.

A variety of indicators can be monitored to detect and react to this type of operating problem. The brine flow rate from the storage chamber and the propane flow rate into the chamber will increase, the tubing pressure will rise and the propane wellhead pressure will drop (although this could be "masked" due to other effects). There will be an abnormal increase in flare stack discharge. Numerous devices have been used to "shut in" the well under these circumstances. The most practical seems to be sensing the rate of rise in brine flow; however, there are several operating situations that can "fool" all devices now in use.

Another point is worth noting. The sonar caliper strapping table is based on a vertical line. The tubing is assumed to be on the same vertical line. The length of the tubing string can be measured into the hole. The end of the tubing string is the "fill" point of the storage chamber. It is always possible that the end of the tubing is *not* where it is supposed to be: The tubing could have been bent while running it into the holes, the last joint could have dropped off, someone could have made a mistake in measurement or in addition. It is always necessary to establish where the end of the tubing is vertically, in relation to a point on the strapping table (this is the "fill" point of the storage cavern). The end of the tubing is initially located using a gyro stabilized azimuth and deviation survey and should be checked by collar locator each time an interface survey is run.

Once the propane is in the storage cavern and the well is in a static condition, propane wellhead pressure as related to a known interface point is a fairly reliable indicator the propane storage cavern system is secure. The interface point should be verified periodically by an interface survey. The interface point might go down slightly due to propane expansion with temperature rise, but the interface should not retreat up the solution cavern unless this can be accounted for by the volume of propane removed from the cavern.

The next step in the process is to remove the propane from storage as it is required by the customer. This is essentially the reverse of the propane injection cycle. The propane will flow out of storage due to the differential pressure. Brine is pumped down the tubing to maintain a required differential pressure. A barrel of brine will displace somewhat more than a barrel of propane (at surface pressure conditions) from the well. If less brine is put in than propane removed, the propane wellhead pressure will drop; if more is put in than removed, the pressure will rise. Obviously turbine meters at the wellhead must have an "in" and "out" counter and the operator must be able to monitor the propane in, brine out, propane wellhead pressure, tubing pressure and have the "feel" of the system to know everything is functioning normally.

MOISTURE ANALYZER

Originally, the propane had a dew point better than −44°F. When it was injected into the storage cavern it contacted the wetted ceiling and walls and brine trapped in inverted pockets in the sidewalls of the cavern, and interfaced with large water areas at the propane/brine contact point. There is always some circulation in the stored propane due to temperature gradients from the bottom to the top of the storage cavern and this could cause upward movement of moisture into the propane. If the storage well is "worked" quite often (i.e., propane put in and taken out without actually emptying the cavern), the propane in the upper portion of the storage cavern could be quite dry while that in the lowermost portion would be saturated at the bottom hole temperature (90°–100°F).

Propane is sold on a −15°F dew point specification so it must be dried before delivery is made. The product recovery system has a dehydrator in it to perform this function. The propane returning from the storage chamber first goes through a "scrubber" where any "free water" is knocked out, then it passes through a vertical pressure vessel containing a desiccant that will remove moisture, then through the measurement unit and thence into pipeline and to the distribution net. A composite sample proportional to the rate of flow is taken on a continuous basis and spot samples (if there is no on-stream analyzer) are taken to verify the propane meets all sale specifications.

The moisture analyzer performs a secondary function by indicating when the dehydrator desiccant is starting to become "loaded" wth water. When this point has been reached, a "dry" tower is switched onto the line and the "wet" tower is regenerated (i.e., the moisture is driven out of the desiccant by heat). The dehydrator regenerative system has various indicating and recording instruments to track the course of the drying cycle and determine when it is finished.

This completes the process narrative. Some steps have been skipped, others have been brushed over lightly, some have probably been unduly emphasized. In any event, the reader should have a fair grasp of the various operational aspects of the propane import terminal supported by an underground storage facility. The various parts of the facility can be literally scattered over square miles of terrain with major components separated by considerable distances. Every part must mesh into the whole if the end objective is to be met in a safe and economical manner. Operations are carried on night and day, fair weather or foul, personnel are wide awake and alert or tired and listless, a pressure liquid is treated with respect or considered as just another commodity, everything is steady and routine for hours and days on end, then that sudden breathtaking emergency can occur.

SPECIAL PROBLEMS

It would be somewhat misleading to infer that the product handling and storage systems described in this paper do not have operating problems. Actually, new problems, in particular those associated with storage wells and disposal wells, crop up frequently, invariably at night or on a weekend. The atmosphere in the operating area seems to be permeated with minute salt crystals, the soil is "hot" and electrical and instrumentation maintenance is a never ending chore. The storage operators, maintenance and instrument men have very few dull moments.

The brine side of the storage system seems to give the most trouble. Starting with brine at bottom hole temperature in the storage chamber, say at 90°F BHT, the brine is 103% saturated. For each 10°F temperature drop, 1% of the salt will be precipitated. Some salt "plates" out on the inside of the tubing, as brine flows counter to the incoming cool propane on its way to the surface. The reduced tubing flow area causes pressure fluctuations on the propane side of the wellhead. The tubing can plug completely if proper operating procedures are not followed. The brine flow carries fine "sands" out of the storage cavern and at times contains free crystals of salt. These particles can plug small instrument orifice openings, erode metal objects in their path, settle behind orifice plates in flow lines and in the brine pit. A slight temperature drop can cause some salt to "fall out" in the most unusual places. Saturated saltwater brine is generally considered to be a "difficult" material in reference to measurement (devices) and corrosion. Strangely enough a saturated brine is not very corrosive. Atmospheric fallout of salt crystals and "seep" or "spray" residues permeate cracks, fissures, linkages, etc., and in the presence of trace moisture do create corrosion points. Cast aluminum housings are severely attacked. All instrument closures should be weather tight. At times, it is advisable to use oil "buffers," "seals," or diaphragms to separate brine from liquid contact instruments (pressure gauges, DP calls, pressure transmitters, etc.).

The brine disposal pumps really take a "beating" from corrosion (exterior), erosion (interior), loss of suction, overranging flows at startup (when brine disposal wells are on vacuum), variable flow rates as disposal formation starts taking brine (or flow line area decreases due to salt plating out), and no flow if the disposal well should plug. The protective instrumentation systems (high/low pressure, no flow, etc.) on the pump must be effective.

The propane side of the system is not as tricky. Propane is "nonlubricating" on bearings or close tolerance moving parts (P.D. meter elements) and they can bind. On the refrigerated side of the system the inlet liquid must displace an appropriate amount of "in tank" vapor back to the tanker to prevent tank pressure buildup or tanker compartment vacuum. The vapor generator and/or blower "kicks in" to prevent the latter situation, and the vapor relief (dump) valve prevents dangerous overpressure of the tank. When liquid is taken out of the tank the pressure in the vapor space must be maintained at an acceptable level. At −44°F it is conceivable propane would not vaporize at a sufficient rate to do this. The vapor generator (or purge gas) system must make up the required volume or the vacuum relief (vent) valve will open and allow atmospheric air to enter (in preference to "pulling the tank in") which is not such a happy event. Needless to say, meeting and mastering the integration of actions and interrelated reactions can drive an irritable instrument man mad.

Propane at atmospheric pressure and ambient temperature will vaporize quite rapidly. The vapor is heavier than air, will flow downhill and fill any depressions. It is always embarrassing to have any amount of propane leaking to the atmosphere and downright dangerous if a pipeline should develop a sizeable leak or rupture. It is advisable to have leak detection capability on any pipeline; it is particularly important on one carrying a pressure liquid. Computer comparison of "in flows" and "out flows" with corrections for variation in line fill due to temperature or pressure change should catch a major leak, trigger block valves on each side of the leak and cause progressive shutdown of shoreward facilities back to main tank outlet valves. The same type of arrangement should be used on the line to the distribution pipeline pump station with successive shutdowns (automatic) back to the displacement pump. These sorts of instrumentation and measurement balance problems are reasonably straightforward.

About the only unusual type of problem at the storage cavern wellhead not previously mentioned is propane flow line failure. If the inbound flow line leak is large enough during injection, the wellhead will shut down due to low flow inbound; alternately it would shut down because of high back flow from the storage chamber to the leak. During the recovery cycle the wellhead would shut down due to high flow outbound. If the leak is not large enough to create flow rates that will trigger this system, detection could be by hydrocarbon sensing device, by sound detection, or by sight. Under such circumstances, the entire system can be shut down by manually activating the switch at remote shutdown stations or by use of the master emergency shutdown switch on the control room console.

SYSTEM PRESSURE CRITERIA

The weakest point in solution mined caverns is usually at the casing seat of the final cemented casing string. The wellhead is designed for the working pressure anticipated in the system. The casing is tested, sometimes before and always after it has been run and cemented, to a pressure well above the maximum pressure expected to be exerted in it. This pressure test is made before drilling out the casing shoe. Most operators then drill some 10 to 15 feet below the casing shoe and test the cementation job and formation at the casing seat. The magnitude of this test is generally based on a percentage of the expected hydrofracing pressure of the overburden above the casing shoe. For instance, it might be assumed that hydrofracing would occur at 1.0 psi/ft. times depth of the casing seat and a test run at 0.8 or 0.9 psi/ft. It must be understood that for a given design flow rate, the flow areas in the product annulus, in the brine tubing, in the brine flow line to the pit, in the product return line to the distribution system, the allowable erosion velocities in the annulus and tubing, the specific gravity of the stored product and brine, the total depth to the end of the brine tubing (fill point) in the storage cavern, and the operating pressure safety factor desired *all* impact on the depth at which the casing seat must be set. When the cavern is solution mined to its desired capacity, it is again hydrostatically tested with the desired safety factor.

For example, given:

1. Flow areas in product annulus and brine tubing sufficient that erosion velocity limits are not exceeded.
2. Product specific gravity = 0.500
3. Brine specific gravity = 1.200
4. Allowable overburden pressure = 0.8 psi
5. Casing seat depth = 2,000 feet (assumed)
6. End of tubing = 3,000 feet (assumed)

The following calculations can be made to determine the operating pressure at the casing seat under design flow conditions and the pressure to be exerted on the brine side wellhead gauge to test the solution mined storage system:

$Pu + \Delta P_a + \Delta P_t + \Delta P_b$	$= P_1$	Product side wellhead gauge reading
$P_1 - \Delta P_a + P_p$	$= P_{es}$	Operating pressure at casing seat
$P_{es} \times 1.3$ SF	$= P_{est}$	Test pressure at casing seat
$P_{est} - P_b$	$= P_t$	Test pressure on brine wellhead side gear
P_p	=	Force exerted on casing seat by product column weight
P_b	=	Force exerted on casing seat by brine column weight

Where:		psi
Pu	= U-tube pressure effect at fill point $= 3000 \times .433\,(1.2 - .5)$	= 909
ΔP_a	= Pressure drop in annulus at design flow rate	= 50 (assumed)
ΔP_t	= Pressure drop in brine tubing at design flow rate	= 45 (assumed)
ΔP_b	= Back pressure in brine return system	= 20 (assumed)
P_1		= 1024
ΔP_a		= (50)
P_p	$(2000 \times .433 \times .50)$	= 433
P_{es}		= 1407
P_{est}	$= 1407 \times 1.3$	= 1829
P_t	$= 1829 - 2000\,(.52)$	= 789

INSTRUMENTATION AND CONTROLS

The format and sequencing of the subject matter in this paper has been deliberate. It is hoped the reader's interest has been aroused by at least a few of the operational aspects, and that various questions now lurk in his mind—"How would I design this particular segment of the Instrumentation?" "What end device should I use?" "Are there problems I see (re instrumentation) that the writer has not?"

Most of the hardware is "off-the-shelf stuff" and the majority of the instrumentation design is simple and routine. Some of the hardware has just recently been developed and is subject to the usual "growing pains"—some is experimental and very unreliable. This is not a complicated system in comparison to a refinery or petrochemical plant. It is a system, however, that handles a volatile and expensive material at elevated pressures using a very unique storage scheme operating at relatively high rates of flow having widely scattered major units all of which must be integrated and controlled to maintain a system balance.

A comprehensive control system, equipped with appropriate and reliable devices sending pertinent and timely information to control points manned by a single operator backed with alarming and properly sequenced emergency shutdown systems is as vital in this system as in any other—all functions requiring control must be recognized, an instrumentation system must be designed such that it will perform the required function, be easily maintained, give adequate readouts on properly laid out panels, and "fail safe."

What instrumentation is really needed? What is the most reliable device to perform a particular function? Where should it be located? What does the control room operator need to know? How should data be displayed? How is the signal to be transmitted to the readout area? In what position, and under what conditions should it "fail safe"?

Table 3 at the end of this paper gives a list of local and console-mounted indicators and recorders that might typically be used in a system such as this. It is not the intent of this paper to recommend any particular approach to instrumentation, to prescribe specific devices or to set out a complete instrumentation design package. The paper should be used as a reference only, and in no event to be considered as representing an existing design, a workable system, or a complete equipment itemization. No attempt has been made to cover protective instrumentation on machinery packages (such as vibration switches, high bearing temperature, no flows, etc.).

Figures 2 and 3 show an instrumentation concept that might be used on a storage cavern wellhead and on a brine disposal wellhead.

It is best to start at the various control room consoles and make the decision as to what readout, alarms, manual shutdowns, etc., might be required there. The functional location of status, indicating, transmitting and recording instruments are shown for field and control room console on the same chart for convenience (see Table 3).

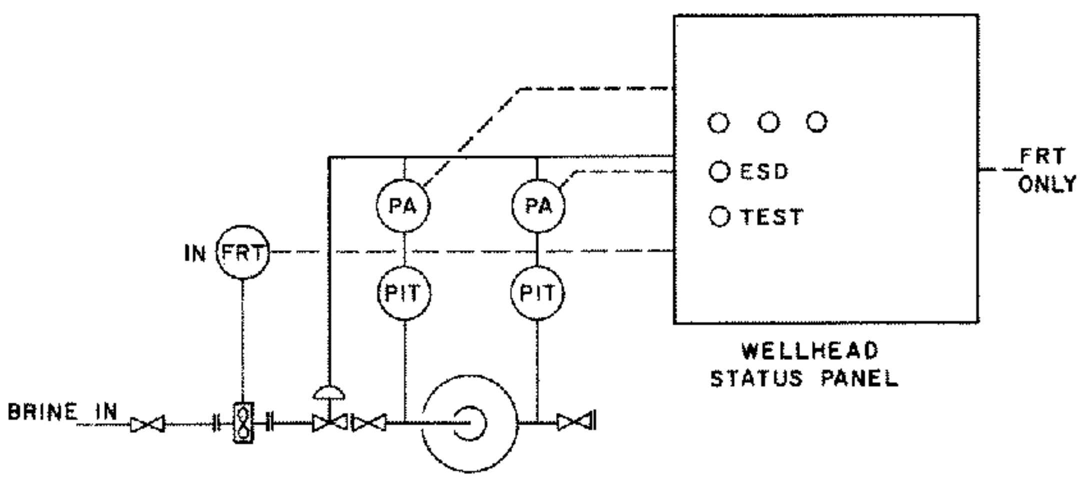

Figure 3. Brine disposal well, wellhead instrumentation.

TABLE 1

A Type Failure	B Class	C Indicator at Surface	D Detection	E Control Action	F Control Device	G Alarm	H Auto Shutdown	I Correction
I. Tubing thread leaks or small hole in tubing in stored product area	N	1. Small quantity of product returns through tubing to surface along with displaced brine	1. Hydrocarbon detector in brine pit or tank	1. Flare	1. None	1. Yes	1. No	1. Use thread seals 2. Centralize tubing in deviated bore hole 3. Pull tubing (O)
II. Large hole or split in tubing in stored product area	S	1. Moderate to large quantity of product returns through tubing to surface along with displaced brine 2. Tubing pressure increases 3. Tubing flow rate increases	1. Same as I.D.1 & 2 2. High tubing flow rate	1. Flare 2. Shut in well	1. Tubing PI & PT 2. Tubing FR & FRT	1. Yes	1. Yes	1. Pull tubing (O) or (M) and replace with new string
III. Hole in casing at Loss of Circulation Zone; or casing seat washout connected to Loss of Circulation Zone	C	1. Tubing pressure drops 2. Product injection pressure drops 3. Displaced brine flow rate drops or flow stops	1. Visual—gage low pressure 2. Visual—brine return line 3. Various alarms & shutdowns	1. Stops injections 2. Run continuous interface surveys to determine rate of outflow	1. Brine PIT shuts MOV 2. Product PIT shuts MOV 3. Variance control—product in vs. brine out shuts both MOV's	1. Yes	1. Yes	1. Empty cavern and correct leakage
IV. Washout to skirt of Dome	C	1. Same as III C,D,E, F,G, & H.	1. Same as III.C,D, E,F,G. & H.	1. Same as III.C,D, E,F,G. & H	1. Same as III.C,D, E,F,G, & H.	1. Yes	1. Yes	1. Abandon Cavern[1]
V. Coalescence with adjoining unusable cavern	C	Same as IV	Same as IV	Same as IV	Same as IV	1. Yes	1. Yes	1. Abandon Cavern[1]
VI. Fracture (due to overpressure) which intersects Loss of Circulation Zone	C	Same as IV	Same as IV	Same as IV	Same as IV	1. Yes	1. Yes	1. Abandon Cavern
VII. Roof fall that intersects Loss of Circulation Zone	C	Same as IV	Same as IV	Same as IV	Same as IV	1. Yes	1. Yes	1. Abandon Cavern

Notes:
[1]It may be possible to use the portion of the cavern above the washout (or upper shoulder of the coalescence corridor by injecting product to this level and withdrawing product by use of submersible pump set at or slightly above the balance point between product and formation pressure or L. C. Zone pressure.
[2]N–Nuisance only; S–Serious; C–Critical; O–Optional; M–Mandatory.
[3]Additional failure mechanism will be available on request.
[4]Non standard abbreviations used: EDSA–Emergency Shutdown—Automatic Trip, ESD–Emergency Shutdown—Manual Trip; PLT–Pig Launch Trip; PRT–Pig Receiver Trip; IL–Indicating Light; MTP–Meter Ticket Printer and Register.

TABLE 2

Standard Symbols Identification Chart
Instrumentation and Controls

Symbol	Identification
FA	Flow Alarm, high/low
FI	Flow Indicator
FR	Flow Recorder
FRC	Flow Rate Controller
FT	Flow Transmitter
LA	Liquid Level Alarm, high/low
LG	Liquid Level Gauge
LI	Liquid Level Indicator
LT	Liquid Level Transmitter
MOV	Motor Operated Valve
MTP	Meter Ticket Printer
PA	Pressure Alarm, high/low
PI	Pressure Indicator
PIT	Pressure Indicator Transmitter
PR	Pressure Recorder
PT	Pressure Transmitter
TI	Temperature Indicator
TR	Temperature Recorder
TT	Temperature Transmitter

TABLE 3

LPG Import Terminal—Instrumentation and Controls

Indicators	Local		Console	
Tanker discharge				
Liquid discharge arms	(PT)	(TI)	—	
Vapor return arms	(PI)	(TI)	—	
Liquid flow line	(PI)	(TI)	—	
Vapor return line	(PI)	(TI)	—	
Meter, flow rate, propane	(PI)	(TI)	—	
Volume, accumulator readout (reset)	(FR)	(FT)	(FR)	MTP
Refrigerated tank				
Liquid				
Level	(LG)	(LI)	(LI)	
High level, set point			ESDA	
Low level, set point			ESDA	
Temperature	(TI)	(TI)	(TR)	
Main valve position, inlet			IL	
Main valve position, outlet (to booster)			IL	
Valve position, outlet (to holding refrigeration)			IL	
Vapor				
Pressure, vapor space	(PIT)			(PR)
High, set point			ESDA	
Low, set point			ESDA	
Valve position, vapor to tanker				IL
Meter flow rate, vapor to tanker			(FI)	
Blower, vapor booster, on/off				IL
Pump, holding refrigeration, on/off				IL
Compressor, holding refrigeration, on/off (Note 1)				IL
Chiller				
Meter, flow rate, propane to refrigerated tank	(PI)		(FI)	
Temperature, outlet	(TI)	(TI)	(TR)	
Pump, booster (from tank to suction side pipeline pump)				
Flow rate			(FI)	
On/off			IL	
Heater				
Meter, flow rate, fuel, direct firing burner	(FR)		(FI)	
Temperature, liquid, heater inlet	(TI)			
Temperature, liquid, heater outlet	(TI)	(TI)	(TR)	
Temperature, gas turbine exhaust, inlet to heater	(TI)			
Temperature, gas, heater stack	(TI)			
Pipeline pump				
Pressure, discharge	(PIT)		(PR)	
Pressure, suction	(PI)			
On/off				IL
Meter, pipeline (shoreside)	(PI)	(TI)		
Flow rate			(FI)	
Volume, accumulator readout (reset)			MTP	
Flare stack				
Flow rate, meter, vapor to stack			(FR)	
Pilot, on/off	IL		IL	
Purge gas generator[1]				
Supply tank level			(LI)	
Flow to purge system			(FI)	
Pressure	(PIT)		(PR)	
Fire pump(s) on line				
Alarms	*Horn*		*Horn*	
Remote Master Shutdown has been triggered			IL	

TABLE 3 (cont.)

	Local	Console	
Tanker			
Propane discharge has stopped		IL	
Vapor return flow has stopped		IL	
Refrigerated tank			
Liquid level, high set point exceeded		IL	(LA)
Liquid level, low set point exceeded		IL	(LA)
Pressure, vapor space, high set point exceeded		IL	(PA)
Pressure, vapor space, low set point exceeded		IL	(PA)
Pump, holding refrigeration, off line		IL (blink)	
Compressor, holding refrigeration, off line		IL (blink)	
Chiller			
Temperature, outlet, high set point exceeded		IL	
Heater			
Temperature, outlet, low set point exceeded		IL	
Temperature, outlet, high set point exceeded		IL	
Pipeline pump			
Pressure, suction, low set point exceeded		IL	
Meters, propane (shoreside vs. storage site)			
Volume, pipeline in vs. out, variance above preset limit		IL (blink)	
Flare stack			
Pilot flame is out		IL	
Fire in shoreside area		IL (blink)	
Emergency Shutdowns			
Master	ESD	ESD	
Tanker dock			
Valve, loading arm, liquid, shut		ESD	
Valve, loading arm, vapor, shut		ESD	
Refrigerated tank			
Valve, main liquid inlet, shut		ESD	
Valve, main liquid outlet, shut		ESD	
Valve, liquid outlet to holding refrigeration, shut		ESD	
Valve, vapor outlet to tanker, shut		ESD	
Valve, dump tank to flare stack, open	ESDA	ESD	
Valve, dump purge gas to tank, open	ESDA	ESD	
Pump, booster, off			
Pump, holding refrigeration off		ESD	
Compressor, holding refrigeration off		ESD	
Fuel			
Valve, fuel to heater, shut	ESDA	ESD	
Valve, fuel to gas turbine, shut	ESDA	ESD	
Mainline valve, pipeline injections, shut	ESDA	ESD	
Fire pump, start		ESD	

Note 1—Can be gas other than propane

Underground Storage Site Instrumentation

Propane Injection Cycle

Indicators

	Local	Console
Pipeline from shoreside		PLT
Valve position, mainline		IL
Pressure, propane, delivery	(PIT)	(PR)
Volume, propane in, accumulator reading (reset)		MTP

TABLE 3 (cont.)

	Local	Console
Propane Receipts		
Meter, pipeline (storage site)		(PRT)
Flow rate		
Volume, propane, in,		
accumulator readout (reset)		MTP
Mainline valve, position, flow line		
to distribution pipeline		IL
Valve, position, flow line to storage chambers		IL
Wellhead, storage chamber in use		
1, (2), (3), (4), etc. on line		IL
Valve position, propane		IL
Valve position, brine		IL
Pressure, propane (casing)	(PIT)	(PR)
Pressure, brine (tubing)	(PIT)	(PR)
Meter, flow rate, propane in		(FI)
Meter, flow rate, brine out		(FI)
Meter volume, propane in,		
accumulator readout		MTP
Meter volume, brine out,		
accumulator readout		MTP
Liquid lever indicator, brine pit	(LT)	(LR)
Pumps, brine disposal in use 1, (2), (3), etc.	FRC	IL
Pressure, discharge	(PIT)	
Wellhead, brine disposal well in use		
1, (2), (3), (4), etc.		IL
Meter, flow rate, brine in		
(out of pipeline)		(FI)
Pressure, brine (tubing)	(PIT)	(PR)
Pressure, oil (casing)	(PIT)	(PR)
Alarms		
Remote Master Shutdown has been triggered		IL (blink)
Master Shutdown at Shoreside site		
has been triggered		IL (blink)
Flow has stopped from shoreside pipeline		IL
Wellhead, storage chamber in use		
1, (2), (3), (4), etc.		
Off line		IL
Level, brine pit, above preset limit		IL
Pump, brine disposal, by use 1, (2), (3), etc.		
Off line		IL
Wellhead, brine disposal well in use		
1, (2), (3), (4), etc.		
Off line		IL
Flare stack, pilot flame, out		IL
Fire in operating area		IL
Emergency Shutdowns		
Master	ESD	ESD
Pipeline		
Mainline valve, shut	ESDA	ESD

TABLE 3 (cont.)

	Local	Console
Wellhead, storage chamber		
Close propane and brine valves		ESD
Pressure, propane, above/below preset limit	ESDA	
Flow rate, propane, in, above/below preset limit	ESDA	
Flow rate, brine, out, above/below preset limit	ESDA	
Flow rate, propane in vs. brine out, variance above preset limit	ESDA	ESD
Pump, brine disposal		
Shutdown		ESD
Pressure, discharge above preset limit	ESDA	
Flow rate, inlet below preset level	ESDA	
Wellhead, brine disposal		
Close brine valve		ESD
Pressure, tubing, above/below preset limit	ESDA	
Pressure, casing, below preset limit	ESDA	
Propane Recovery Cycle		
Indicators		
Pump, propane displacement, brine, in use		
1, (2), (3), etc.	FRC	IL
Pressure, discharge	(PIT)	(PR)
Brine pit level		(LI)
Wellhead, Storage Chamber in use		
1, (2), (3), (4), etc.		IL
Valve, position, propane,		IL
Valve, position, brine,		IL
Pressure, propane (casing)	(PIT)	(PR)
Pressure, brine (tubing)	(PIT)	(PR)
Meter, flow rate, propane out		(FI)
Meter, flow rate, brine in		(FI)
Volume, propane out, accumulator readout		
Volume, brine in, accumulator readout		
Dehydrator		
Tower 1, (2) on/off line		IL
Moisture content, propane	ESDA	Recorder
Valve position, by-pass valve is open/closed		IL
Meter, master		
Volume, propane to pipeline, accumulator readout (reset)		MTP
Pipeline to distribution system		
Valve position, mainline, open/closed		IL
Pressure, propane	(PIT)	(PR)
Alarms		
Wellhead, Storage Chamber		
Storage well in use 1, (2), (3), (4), etc. Off line		IL (blink)
Pump, propane displacement, brine		
Off line		IL

TABLE 3 (cont.)

	Local	Console
Brine pit level		
Below preset limit		IL
Dehydrator		
Tower in use is off the line		IL
Moisture content of propane is above preset limit		IL
Meter, Master		
Volume delivered to pipeline at storage site is more than that received at pump station (exceeds preset variance limit)		IL (blink)
Pipeline		
Mainline valve is closed at Storage site (delivery)		IL
Mainline valve is closed at pump station (receipts)		IL
Emergency Shutdowns		
Master (and remote masters)	ESD	ESD
Pipeline to distribution system		
Valve, mainline, shut		IL
Wellhead, storage chamber in use		
Close propane and brine valves		ESD
Pressure, propane, below preset limit	ESDA	
Flow rate, propane out, above/below preset limits	ESDA	
Flow rate, brine in, above/below preset limits	ESDA	
Flow rate, propane out vs. brine in, variance above preset limit	ESDA	ESD
Pump, product displacement, brine shutdown		
Shutdown		ESD
Pressure, high/low	ESDA	
Flow rate, inlet, low	ESDA	
Dehydrator, shutdown		
Free water knock out drum		ESD
Liquid level, high	ESDA	
Pipeline to distribution system		
Mainline valve, shut		ESD
Pressure, below preset limit	ESDA	IL
When volume measured into pipeline at storage site is less than that received at pump station (exceeds preset variance limit)	ESDA	

TABLE 3 (cont.)

Status Panel
Storage Chamber Wellhead
Status lights (lamp "first" out stays lit)
Pressure, propane, high
Pressure, propane, low
Pressure, brine, high
Pressure, brine, low
Flow direction, propane
In
Out
Flow rate, propane, high
Flow rate, brine high
Flow rate, brine, high
Flow rate, propane in/out vs. brine out/in exceeds preset limit
Lamp test circuit button
Local Emergency Shutdown button (also "test" shutdown valve and sensing end device operation with time delay)

*Nonstandard Symbols Used.

ESDA Emergency Shutdown—Automatic Trip
ESD Emergency Shutdown—Manual Trip
PLT Pig Launch Trip
PRT Pig Receiver Trip
IL Indicating Light
MTP Meter Ticket Printer and Register