CAPACITY AUGMENTATION OF NUMALIGARH – SILIGURI MULTI-PRODUCT PIPELINE

A thesis submitted in partial fulfillment of the requirements for the Degree of
Master of Technology
(Pipeline Engineering)

By

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CERTIFICATE

This is to certify that the work contained in this thesis titled "CAPACITY AUGMENTATION OF NUMALIGARH–SILIGURI MULTI-PRODUCT PIPELINE" has been carried out by SAJEEV C under my supervision and has not been submitted elsewhere for a degree.

19/05/2008

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ABSTRACT

Pipelines, the lifeline of countries' transport sector and energy sector, transports 67% of total petroleum products. Energy saved is energy created. Utilizing the available resource to its maximum extent has to be adopted. Pipelines in India, operates only to 68% and below of its maximum capacity. Options to tap this potential have been given in this thesis. Increasing the effectiveness of the pipelines has been concentrated through capacity augmentation.

Capacity augmentation of 660 Km Numaligarh-Siliguri Product Pipeline has been carried out in this project. Capacity augmentation of pipeline can be done by methods like Looping, Addition of Drag Reducing Agent and Increase in number of pumping stations or increasing the MAOP if permissible. In product pipelines all these methods are not applicable for capacity augmentation. Looping is one of the methods which is not applicable for capacity augmentation of product pipeline. Usage of Drag Reducing Agent is limited to only when there is an excess demand in pipeline supply. Presently, Drag Reducing Agent is not used extensively in India unless demand is too high. The main reason for this limited use is the numerous problems in compatibility when various products are transported through the pipeline. Further the quality of the product also should not be affected.

The last method of changing the capacity is by increasing the MAOP. The design parameter and further calculations did reveal possibility of enhancing the MAOP of the line and accordingly the project was undertaken. Two cases have been discussed, increase in flow rate by 13% and by 20%. The capacity is increased from 1.721 MMTPA to 1.94473 MMTPA in first case which involves a cost increase of 68 lakhs for the excessive pump of 250 Hp that has to be installed. In the second case the capacity is

increased by 20% of actual flow, 1.721 MMTPA to 2.0652 MMTPA. This involves a cost increase of 115 lakhs for the excessive pump of 400 Hp that has to be involved. Flow increase by 13% is more preferred in cost wise and better life of pipeline in long run. During very high requirement there is a provision for operating the pipeline up to 2.0652 MMTPA, by which the extra demand requirements during peak season period is met.

The various methods for capacity augmentations in pipelines, calculations involved in determining the enhancement of capacity, the various issues involved, all in an Indian perspective, are being discussed in this working paper. The methods prevailing for capacity augmentation are compared with requisite recommendations for selection and usage.

CHAPTER -1
INTRODUCTION

1.1 INTRODUCTION

Petroleum products widely contribute to the energy requirements of our nation. Petroleum is considered as the blood of the nation. The countries development depends upon the availability and usage of petroleum and its products. Availability of crude decides the amount that is being refined to obtain petroleum products and demand in the market. Transportation of crude to refineries and refined products to market is a bottleneck operation which decides the demand.

Transportation of crude and products are generally carried out by three means. They are roadways, railways and seaways. With the technology development, new cheaper and safer modes of transport have being introduced. Pipeline is best method the new technologies have awarded. Pipeline transports required quantity from one point to another. It is considered as the best and safe method for transportation of large quantity of any type of product like liquid, gaseous or slurry products.

There are approximately 200,000 miles of crude oil and petroleum product pipelines in all 50 states of this country. The liquid pipeline infrastructure constitutes a fundamental part of our national economy. Pipelines carry about 68% of the petroleum and petroleum products moved domestically. About 27% of the remainder is moved by water and about 5% by truck or rail.

Pipelines have, proved to be the best mode for transporting petroleum products. The feasibility of pipelines in developing countries like India lies in the ability to design in the most, difficult terrain, to be practically unaffected by weather and to finish transport of petroleum products at lower cost. Pipeline network are always necessary to standardize the surface transport system. They can go long way in reliving the overloaded surface transport system. Pipelines also have the added advantage of being able to carry a number of commodities and also being the safest way of transporting inflammable goods. Batching of products controls the market demand as it is the main requirement of consumers.

Pipelines are an extremely efficient transportation system. To replace a 150,000-barrel per day pipeline, which is merely an average sized pipeline, we would need 750 trucks per day requiring a truck to arrive and load or unload every two minutes. Replacing the same truck with a unit train of 2000-barrel tank cars would require a 75-car train to arrive and be unloaded every day. As an industry, pipelines depend on a relatively small national workforce of approximately 13,000 skilled men and women. That modest workforce, however, and the 200,000 miles of pipelines for which they are responsible, transport over 600 billion ton-miles of freight each year.

1.2 DEVELOPMENT OF PIPELINE TRANSPORTATION

The pipeline system began its journey almost a hundred years. The first cross-country oil pipeline was laid in Pennsylvania in 1879 from Bradford to Allen town, about 109 miles long and 6" in diameter. The success of this pipeline prompted the United States to develop more pipelines in their country. The long distance pipeline transportation got a boost during World War II when coastal tanker traffic was disrupted. The pipelines were used as a foolproof way of transporting petroleum products. Later discoveries of giant oil fields in remote parts of the world led to planning and execution of correspondingly large pipeline networks. Many oil fields were discovered in desert areas which lead to more development of pipelines. Since road transportation was a very big problem, pipelines were developed. This concept caught on very fast and pipelines were built mainly from oil refineries to distributing centres. Thus, pipeline industry has grown in parallel with the development of world oil industry over the last one-century.

Most of the earlier refineries in India were installed at coastal locations, thus depending on coastal movement of crude oil. Further, the refining capacities being low, the products were either consumed locally or transported to the consumption centres by rail or road. After 1960, most of the refineries were installed in land-locked locations and crude and product pipelines were promptly laid. The first crude oil pipeline was laid from Digboi oil fields to Digboi refinery. Though this was a very small project it was a benchmark for further improvements in the Indian pipeline industry. During 1960-63, Oil India limited laid the first trunk crude oil pipeline, 1156 km long from Naharkatiya and Moran oil fields to the refineries at Guwahati and Barauni. The first cross-country product pipeline was laid during 1962-64 to transport products from Guwahati refinery to Siliguri. Subsequently, a number of product and crude oil pipelines were laid in the 60's, 70's and 80's, including sub-sea crude oil pipelines.

The pipelines laid during the 60's were designed, engineered and constructed by foreign companies. However, the exposure to this technology enabled Indian engineers to gain confidence, and the pipelines, which came up later, were designed and constructed with indigenous expertise. The country today has about 13,000 km of major crude oil and product pipelines. There are also a number of pipelines in the conceptualisation and building stage.

1.3 ADVANTAGES OF PIPELINE SYSTEM

The main advantages of the pipeline system are: -

- Product handling is minimal.
- Offers large scale economy in transportation.
- Energy consumption is less.
- Reliable mode of transportation.
- Transit losses are lower.
- Impact on environment during construction, operation and maintenance is negligible.
- Pipelines can be used all through the year.
- Multiple products can be handled.
- Pipelines can traverse difficult terrains.
- Flexibility in transport as the volume transported can be increased or decreased at a negligible cost.
- No consumption of energy for the transportation of dead weight containers.

Roadways, railways and seaways have always been the most common modes of transportation. The main disadvantages of these systems are: -

- The time consumption is more.
- Additional energy is consumed
- Safety hazards involved.
- Running these systems requires energy, which is again uneconomical.
- Losses due to evaporation, accounting and manual handling.

Therefore there is a need to develop such a mode of transportation, which is both safe and economic. The pipeline system of transportation is safe, economically viable and also environmentally friendly.

1.4 Categories of Petroleum Product Pipeline

The petroleum product pipelines would be categorized as follows:-

(i) Pipelines originating from refineries, whether coastal or inland, upto a distance of around 300 kilometers from the refinery;

(ii) Pipelines dedicated for supplying product to particular consumer, originating either from a refinery or from oil company's terminal; and

(iii) Pipelines originating from refineries exceeding 300 Km in length and pipelines originating from ports, other than those specified in (i) & (ii) above.

There are capacity augmented pipelines in India. Their lists have been given in table 1.

Table 1.1: Capacity Augmented Pipelines in India

Name Of The Pipeline	Capacity (MMTPA)	Length Of Pipeline (Kms)	Diameter Of The Pipeline (inch)	Augmented To Capacity (MMTPA)
Mumbai-Manmad Pipeline	4.3	252	18	6
Mumbai-Manmad Pipeline extension project to Manglya	1.4	358	14	3.5
Chennai – Asanur Section	1.800	256	14	2.2
Koyali-Bareja Section	4.100	80	18	4.9
Bareja-Sidhpur Section	3.000	165	18	3.6
Sidhpur-Sanganer Section	3.400	517	18	4.2

1.5 AUGMENTATION

Augmentation is the process of increasing the throughput of a pipeline without changing the basic design like diameter, thickness etc instead using methods like

- Looping.
- Drag Reducing Agent.
- Increasing the number of pumping station.
- Modification in initial condition.

These are the basic methods by which we can increase the capacity of a pipeline. The process of capacity augmentation does not alter the diameter of the pipeline nor changes any basic design of the pipeline. These methods mainly concentrate on increasing the efficiency of the current working environment. The Maximum Allowable Operating Pressure is also not varied for increasing the capacity of the pipeline. In this project documentation it has been discussed how the capacity of a product pipeline can be increased. Capacity augmentation of a crude pipeline and product pipeline is different.

In this thesis, Numaligarh – Siliguri Product Pipeline (NSPL) is taken into account. The capacity of 1.721 MMTPA is being changed to the maximum allowable limit. This pipeline is owned by Oil India Limited. The pipeline travels from Numaligarh to Siliguri through Guwahati, Alipurdaur, and Mal bazaar. The despatch terminal is at Rangapani near Siliguri, where the facility is provided by Numaligarh Refinery Limited (NRL).

PIPELINE DETAILS

Numaligarh – Siliguri Product Pipeline

- **Length** : **660 km**
- **Capacity** : **1.721** MMTPA
- **Products** :
  - High Speed Diesel : **1367** TMTPA
  - Superior Kerosene Oil : **219** TMTPA
  - Motor Sprit : **135** TMTPA

Table 1.2 : Product details

Products	**Sp. Gravity @ 15° C**	**Viscosity cSt**
MS	0.7289	0.51 @ 38° C
HSD	0.850	0.5 @ 37° C
SKO	0.8105	1.18 @ 37° C

- Pumping station : ONE at Numaligarh
- Diameter of the Pipeline: 16 inch.
- Crosses 4 major rivers at 5 places.
- Micro-tunneling used for 3 major river crossings.
- Open cut method used for another river crossing.
- Cuts through rivers and canals at 16 and 27 places respectively.
- 18 Railway crossings.
- Cost of total project without including the cost of augmentation : Rs 468.92 crores

CHAPTER -2
LITERATURE REVIEW

2.1 BASIC DEFINITIONS

To discuss the basics of fluid flow in pipeline systems, it is necessary to first familiarize ourselves with how the key physical properties of fluids affect flow. The term "fluids" includes both liquids and gases. The effect of fluid properties on flow varies with the fluid type, i.e. Compressibility does not significantly affect the flow of liquids since liquids can, for the most part, be considered incompressible. Most of the following fluid properties and pipeline variables should be considered in modeling pipeline systems.

- **Density:-**

Density or mass density of a fluid is defined as the ratio of the mass of a fluid to its volume. Thus mass per unit volume of a fluid is called density. The unit of mass density in SI unit is kg per cubic meter, *i.e.* kg/m^3. The density of liquids may be considered as constant while that of gases changes with the variation of pressure and temperature.

- **Specific Weight:-**

Specific weight or weight density of a fluid is the ratio between the weight of a fluid to its volume. Thus weight per unit volume of a fluid is called weight density

- **Specific Volume:-**

Specific volume of a fluid is defined as the volume of a fluid occupied by a unit mass or volume per unit mass of a fluid.

- **Specific Gravity:-**

Specific gravity of a liquid is the density of the liquid divided by the density of water.

- **Viscosity:-**

Viscosity is the property of a fluid that resists flow, or relative motion between adjacent parts of the fluid. It is an important term in calculating line size and pump horsepower requirements for liquid pipelines. Viscosity varies with temperature. Fluid viscosity will affect flow calculations.

- **Pour Point:-**

The lowest temperature at which oil will flow when cooled under specified test conditions is the pour point. Oils can be pumped below their pour point, but the design and operation of a pipeline under these conditions present special problems.

- **Vapor Pressure:-**

The pressure that holds a volatile liquid in equilibrium with its vapor at a given temperature is the vapor pressure. Vapor pressure is an especially important design criterion when handling volatile petroleum products, such as Liquefied Petroleum Gas (LPG). The minimum pressure in the pipeline must be high enough to maintain these fluids in a liquid state.

- **Pressure:-**

Pressure can be defined as the force or thrust exerted over a surface divided by its area. In the context of pipelines, pressure can be thought of by the same definition. The source of the force applied to a fluid within the pipeline could come from the pumps, which transfer energy to the fluid via pistons or impellers, energy transferred from the reservoir within the earth, or the energy from gravity acting on a column of fluid due to elevation.

- **Hydraulic Gradient:-**

The hydraulic gradient is a profile showing the pressure at any point along a pipeline. In the flow of liquid with a uniform velocity through a pipe of constant diameter, the hydraulic gradient is a straight line. This gradient represents only the pressure loss due to friction, which varies directly with the length of the pipe and the velocity of the fluid. The slope of the hydraulic gradient is proportional to the flow rate. The higher the rate, the greater the slope of the hydraulic gradient.

- **Reynolds number:-**

This dimensionless number is used to describe the type of flow exhibited by a flowing fluid. In laminar flow, the molecules move parallel to the axis of flow. In turbulent flow, molecules move back and forth across the flow axis. Other types of flow are also possible, and the Reynolds number can be used to determine which type is likely to occur under specified conditions. In turn, the type of flow exhibited by a fluid affects pressure drop in the pipeline. The Reynolds number can be calculated for any given liquid and pipe size as follows:

$$\mathbf{Re=VD/\mu} \quad (2.1)$$

Where,

Re= Reynolds Number (dimensionless)

V = average" velocity (ft/sec)

D = internal diameter (ft)

μ = viscosity of the liquid.

It has been shown that for values of Re less than approximately 2000, the flow is laminar. For values of Re above 4000 the flow is considered turbulent. Between these two values lies the "critical zone" where the flow is unpredictable. It is more practical to express the calculation of the Reynolds number in oil field units as follows:

$$\mathbf{Re = 2214\ Q/\ k\ D} \qquad (2.2)$$

Where,

Re = Reynolds Number (dimensionless)

Q = flow rate.

D = internal diameter (m)

k = kinematic viscosity (centistokes)

Or,

$$\mathbf{Re = 35.42\ dQ\ /\mu D} \qquad (2.3)$$

Where,

Re = Reynolds Number (dimensionless)

Q = flow rate

D = internal diameter (m)

d = density (kg/m^3)

μ= Absolute viscosity (centipoise)

- **Friction Factor:-**

A variety of friction factors are used in pipeline equations. They are determined empirically and are related to the roughness of the inside pipe wall. For laminar flow conditions (Re < 2000), the friction factor (f) is a function of the Reynolds number (Re) and is given by:

$$\mathbf{f=64/Re} \qquad (2.4)$$

For turbulent flow conditions (Re > 4000), the friction factor (f) is a function, of the Reynolds number (Re) and the surface roughness of the pipe wall. The value of f is usually obtained from a chart developed by Moody.

Or

$$\mathbf{(1/\sqrt{f}) = -2\log[(e/3.7D) + (2.51/(R\sqrt{f}))} \qquad (2.5)$$

f = Friction factor

e = Roughness factor

D = Diameter of the pipeline

R = Reynolds number

- **Darcy-Weisbach Equation for Head Loss**

$$h_f = (flv^2) / (2gd) \qquad (2.6)$$

h_f =head loss,

f=Darcy friction factor, dimensionless

L=Pipe length, m

D=Pipe internal diameter, m

V=Average liquid velocity, m/s

g=Acceleration due to gravity,

- **Steady state vs. Transient state:-**

Steady State: - A state or condition of a system that does not change.

Transient state: - A temporary oscillation that occurs in a system because of a sudden change.

We can apply these generic definitions to pipeline models or simulations. Steady state simulations are simply pipeline models, which do not change over time. Steady state models can be single-phase liquid or gas, or multi-phase systems. Models can contain all types of standard pipeline equipment including pipes, pumps, compressors, valves, separators, well bores, etc., but as the name implies, nothing changes over time.

On the other hand, transient simulations are pipeline modes, which can change over time. Again all of the standard equipment types can be modeled, and results of changes to the system can be analyzed. Transient and steady state models are closely related in the sense that all transient models must start out at steady state conditions.

Steady state applications include line sizing, equipment sizing and location, deliverability or capacity analysis, gas lift analysis, bottleneck analysis, well bore analysis, slug catcher sizing, etc. In a sense, steady state simulators can model changes to the system over time by using time stepping techniques. This is useful for modeling changes in supply and demand, or equipment requirements over time, but each time step solution is at constant or steady conditions.

Steady state models do not simulate startup procedures, mechanics and impact of changes, or pressure wave propagation throughout the system. This means that the effects of reinforcing pressure waves, equipment tripping, column separation/collapse, line pack/peak shaving, and relaxation effects are ignored. Since many of the effects are important in pipeline design and operation, transient simulation is a very useful tool.

Transient simulations accurately model startup and shutdown procedures, mechanics of pressure changes, effects caused by equipment and control operations, and effects of pressure waves. Thus, one can optimize startup and shutdown procedures, fine tune the operation of equipment and controls, and design for surge relief.

Other applications of transient simulation include water hammer/surge analysis, design of sequencing systems, stability analysis, cascade control design, real-time predictive system management, temperature shutdown problems, upset control, operator training, batch tracking, operating problem analysis, impact of pipeline rupture, and performance tests of equipment.

- **Station Discharge Head (SDH):-**

It is the head that is required to be discharged at the pumping station for the product to reach the next station, with the required residual head. The SDH is calculated by taking into consideration the friction loss elevation difference and the distance. The ground profile is assumed to be uniform.

$$\mathbf{SDH = L + (H'' - H') + h} \qquad (2.7)$$

Where

L = Distance (m)

H''-H' = Elevation difference (m)

H = Residual head (m)

- **Maximum Allowable Operating Pressure (MAOP):-**

It is the maximum pressure the pipeline allowable in the pipeline based on the pipe material.

$$\mathbf{MAOP = (S * 2T * S.F) / D} \qquad (2.8)$$

Where

S = Yield strength (psi)

T = Wall thickness (inches)

S.F = Factor of Safety

- **Situation Of Pumping Stations:-**

  The steps followed in deciding the location of the pumping stations are:-

  - Calculate SDH required as per energy equation.
  - SDH required > MAOP, more than One station necessary based on the following conditions:-

    Case I: SDH < or = MAOP; ONE station.

    Case II: SDH > MAOP & < 2 MAOP i.e. SDH / MAOP; 2 stations.

    Case III: SDH > 2 MAOP & < 3 MAOP i.e. SDH / MAOP; 3 stations.
  - Depending on value of SDH / MAOP, determine number of stations.

Sometimes the ground profile may not be uniform there may be peaks in the route of the pipeline and, the selected hydraulic gradient between end points may not cross the in-between peaks. Hence it will be necessary to add more stations. Minor variations could be corrected by using higher SDH in the same system with higher wall thickness and higher-grade pipes. Major variations may require addition of pump station. It will also be necessary to adjust the location of stations according to the tap off points and place.

- **Horse Power Required**

$$(Q * H * Sg) / (367.46 * \eta_1 * \eta_2) \qquad (2.9)$$

Where

Q = Flow rate

H = Station Discharge Head

Sg = Specific gravity

η_1 = Pump efficiency

η_2 = Motor efficiency

2.2 THEORY OF FLUID FLOW

When pressure is applied to one end of a section of pipe filled with liquid, the liquid tends to move toward the end with a lower pressure. Due to the friction between the fluid and the pipe wall, the velocity of the fluid varies across the cross section of the pipe. The following equation expresses fluid velocity as a function of the square of the radius or distance from the pipe wall:

$$V = (P\ g_c / 4\ \mu_E\ L)\ (r_w^2 - r^2) \qquad (2.10)$$

Where,

V = velocity, m/sec

P = pressure difference, N/m^2

g_c = acceleration of gravity, (N/m^2)

μ_E = viscosity of the liquid, Ns/m^2

L = length of pipe, m

r_w = internal pipe radius, m

In general, the laminar flow of liquids occurs at Re < 2000, and continues until flow velocity reaches a certain a critical value that depends on pipe size and liquid properties causing Re > 2000. The liquid velocity in laminar flow can be visualized as being divided into many concentric cylinders with friction resisting motion of one with respect to the other Liquid velocity is near zero at the pipe wall and increases to a maximum at the pipe center. This effect of one lamination or thin cylindrical sheet of liquid flowing inside another gives us the name "laminar flow".

As liquid velocity increases, the laminations are subject to increasingly disruptive forces. At some critical velocity where *Re* becomes greater than 2000, the flow pattern begins to break down, and the liquid flow becomes unstable. The instability increases as velocity increases, until the liquid panicles move in random directions, all moving at about the same velocity within the pipe .As *Re* approaches *4000,* the flow is said to be turbulent. Individual particles of fluid move in a turbulent pattern, but as a whole the fluid volume moves at a constant average velocity in the direction of the flow. Between laminar and turbulent flow the liquid is said to be in the transition zone or critical zone. In this critical zone, the relationship of pressure loss and flow is variable and not subject to accurate measurement.

Pipelines are designed to have fluids flow in the turbulent pattern due to the operational advantages of turbulent flow. Since liquid particles are moving approximately at the same velocity across the cross section of the pipe, there is less mixing of the batches of various grades of fluids pumped in sequence. There is also less of a tendency for water or sediment to separate from the fluids, which would decrease the efficiency of the pipeline.

Bernoulli's Equation:-

There are many equations for describing flow of fluids in pipelines. For this course, we are interested only in the liquid equations. Some of the equations are valid only for laminar flow, and some do not account for elevation changes, while others are based on the laws of conservation of energy and the conservation of mass. The equation, which takes all these factors into consideration, is the Bernoulli's equation.

The Bernoulli's equation states that in a steady, ideal flow of an incompressible fluid, the total energy at any point of the fluid is constant. The total energy consists of pressure energy, kinetic energy and potential energy or datum energy. These energies per unit weight of the fluid are:

Thus mathematically, Bernoulli's theorem is written as:-

$$\mathbf{P / (Þ\, g) + v^2 / (2g) + z = Constant.} \qquad (2.11)$$

Pressure energy = $p / Þ\, g$

Kinematic energy = $v^2 / 2g$

Datum energy = z

CHAPTER -3
THEORETICAL DEVELOPMENT

3.1.1 Batch and Fungible Pipeline Service

Petroleum products pipelines also differ by whether they operate on a batch or fungible basis. In batch operations, a specific volume of refined petroleum products is accepted for shipment. The identity of the material shipped is maintained throughout the transportation process, and the same material that was accepted for shipment at the origin is delivered at the destination. In fungible operations, the carrier does not deliver the same batch of material that is presented at the origin location for shipment. Rather, the pipeline carrier delivers material that has the same product specifications but is not the original material.

A pipeline carrier operates in a batch or fungible mode based on its circumstances. Unless there is a more compelling reason, a pipeline operator's selection of its mode of service is based on maximizing operating and economic efficiency. In general, fungible product operation is the more efficient mode of operation. Fungible operation tends to minimize the generation of interface material .Another efficiency of fungible operation is that it permits split-stream operations. In a split-stream operation, material originating at Point A and destined for Points B and C can be delivered at both distant points simultaneously; part of the stream can continue on to Point C while delivery is still underway at Point B. In a batch mode, a delivery operation to Point B means that all pipeline movements beyond Point B cease while the delivery to Point B is completed. Fungible operations also support more efficient utilization of storage tanks. In fungible operations, large storage tanks are used to accumulate or deliver multiple consignments of identical refined products. In batch operations, only one consignment of material is typically held in each tank. Accordingly, storage tanks used in batch pipeline operations tend to be smaller (and, possibly, more numerous) and are not utilized as intensively as storage tanks used in fungible service. Among the pipeline characteristics that determine whether a refined petroleum products pipeline operates in a batch or fungible mode, customer requirements for segregation are an important factor. (Many pipelines operating on a fungible product basis can make provision to accept a distinct batch from a shipper. In doing so the carrier might impose a higher minimum volume requirement or charge a higher tariff rate to cover the higher operating cost of providing the special service.) Nonetheless, many pipelines or pipeline segments serve areas where the structure of the market does not support the "one size fits all" character of fungible service. Another important factor in determining a pipeline's type of service offering is the possible availability of multiple pipelines in the same service corridor. If existing practice and customer service arrangements initially mandate batch pipeline service, it is difficult for a refined petroleum products pipeline carrier to change to fungible service subsequently. On the other hand, if a pipeline carrier serves a transportation corridor using multiple pipelines; it has more flexibility to adopt fungible service. Thus, while an oil pipeline is likely to prefer fungible service, batch service is often the only feasible choice. Like the difference between trunk and delivering carriers, the difference between fungible and batch service is one of scale for many operating parameters. An oil pipeline in batch service has considerably less flexibility to offset operating "hiccups" (such as product contamination at a shipper's terminal tank) than does an oil pipeline operating in fungible service.

3.1.2 Sequencing Product Flow

Products pipelines are routinely capable of transporting various types of products or grades of the same petroleum products in the same pipeline. For example, it is common for a single refined products pipeline to transport various grades of motor gasoline, diesel fuel, and aircraft turbine fuel in the same physical pipeline. (For the most part, oil pipelines do not transport both crude oil and refined petroleum products in the same pipeline.) To carry multiple products or grades in the same pipeline, different petroleum products or grades are held in separate storage facilities at the origin of a pipeline and are delivered into separate storage facilities at the destination. The different types or grades of petroleum products are transported sequentially through the pipeline. While traversing the pipeline, a given refined product occupies the pipeline as a single batch of material. At the end of a given batch, another batch of material, a different petroleum product, follows. A 25,000-barrel batch of products occupies nearly 50 miles of a 10-inch-diameter pipeline. Generally, product batches are butted directly against each other, without any means or devices to separate them. At the interface of two batches in a pipeline, some, but relatively little, mixing occurs. The actual volume of mixed material generated depends on a number of physical parameters, including pipeline diameter, distance, topography, and type of material. As a guide to understanding the volume of interface generated, it would be typical for 150 barrels of mixed material to be generated in a 10-inch pipeline over a shipment distance of 100 miles. The hydraulic flow in a pipeline is also a crucial determinant of the amount of mixing that occurs. "Turbulent flow," as occurs in most pipelines, minimizes the generation of interface, while operations that require the flow to stop and start will generate the most interface material.

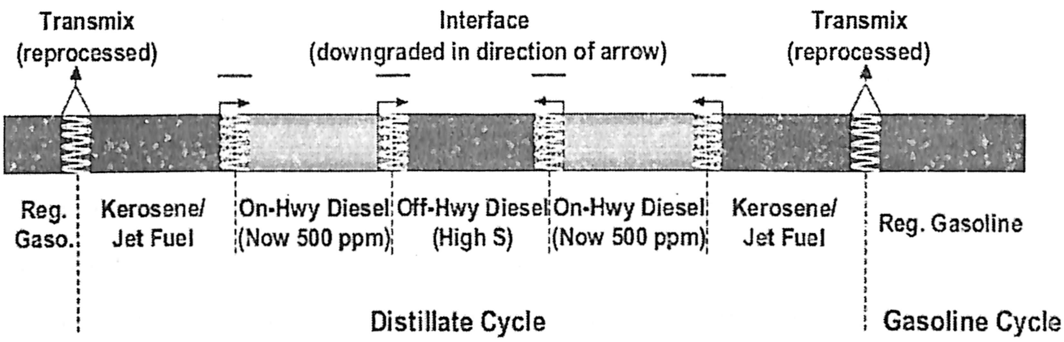

Fig 3.1: Typical Product Sequence and Interfaces in a Refined Products Pipeline

3.1.3 Monthly Batch Scheduling

As a part of their strategy to minimize the generation of interface material, pipeline operators sequence batches on the basis of the total number of products routinely shipped and the number and capacity of storage tanks available at the origin, destination, and intermediate breakout locations. Most often, pipeline operators use a recurring monthly schedule of "cycles," shipping all the available petroleum products of the same type in sequence. For example, only gasoline grades would be shipped during the days that constitute the gasoline cycle, and only distillates would be shipped during the days that constitute the distillate cycle. The actual duration of the cycles might vary from 6 to 10 days, depending on the volume of each material to be shipped during a particular month. Operators accommodate increased seasonal demand and stock builds, for instance, by adjusting the cycle schedule. The schedule is published far in advance, however, leaving little opportunity for last-minute flexibility. Batch sizes are determined by the availability of storage tankage (not only to pipeline operator directly, but also to originating shippers and receiving terminal operators), the batch sizes consigned by shippers, shippers' time requirements, and whether the pipeline is operated on a batch or fungible basis.

3.1.4 Interfaces and Transmix

The composition of the mixed (or interface) material reflects the two materials from which it is derived. While it does not conform to any standard petroleum product specification or composition, it is not lost or wasted. For interface material resulting from adjacent batches of different grades of the same product, such as mid-grade and regular gasoline, the mixture is typically blended into the lower grade. This "downgrading" reduces the volume of the higher quality product and increases the volume of the lower quality product. The interface between two different products—gasoline and a distillate, for instance—produces a hybrid called "transmix." Transmix cannot be blended back into either of its components, as gasoline's flash point will contaminate the distillate, and distillate's higher boiling point will contaminate the gasoline. Transmix, therefore, is segregated and then reprocessed in a full-scale refinery or a purpose-built facility. When it has been separated again into its component products (gasoline and distillate, for instance), the distinct products are reintroduced into the appropriate segregated transportation and storage system. A refined products pipeline typically "wraps" the current highway diesel (at 500 ppm) with kerosene and/or jet fuel (2,000 ppm or so), and non-road diesel (up to 5,000 ppm). The chance that the 500 ppm material will be forced off-specification by sulfur contamination is low. The product tendered is around 300 ppm, leaving leeway for any minor contamination from the neighboring product. Typically, refined oil products are transported from a source location, such as a refinery or bulk terminal, to a distribution terminal near a market area. Large aboveground storage tanks at an origin location accumulate and hold a given petroleum product pending its entry into the pipeline for transport. Petroleum products are also stored temporarily in aboveground storage tanks at destination terminals. Storage tanks usually are dedicated to holding a single petroleum product or grade. Most storage tanks used in pipeline operation are filled and drained up to four or more times per month. Operators usually are able to place the same type of petroleum fuel in a given tank on each drain and fill cycle, and the tank is not purged and cleaned between the routine drain and fill cycles. When a tank is filled and drained with a given material, small to substantial quantities of the former material remain in the tank. To the extent that the previous material was different from new material being placed in the tank, contamination can occur. Generally, such contamination is inconsequential because the new material is substantially the same as the old material or its volume is small. In addition to tanks at the origin and destination terminals, "working" or "breakout" tanks are used in the normal course of pipeline operation. Over a pipeline route, there may be various needs to interrupt the flow of pipeline material in transit, including branching of the pipeline, change in size or capacity, mainline pumping operations, change from fungible to batch operation, and others. In each case, breakout tanks provide the flexibility to temporarily stop or buffer different flow rates of pipeline segments. The maintenance of material in continuous pipeline transit without need for diversion into breakout tankage is known as "tightlining." A pipeline operator's ability to tightline material will prove to be a slight advantage in protecting the integrity of ULSD. Overall, however, tightlining is not an easy option to engage if facilities and operating requirements do not already permit it. In addition to the minor creation of interface material that occurs in pipeline transit, creation of interface material also occurs in the local piping facilities (station piping) that direct petroleum products from and to respective origin and destination storage tanks and in the tanks themselves. Essentially, station piping represents the connection between a main pipeline segment and its requisite operating tanks. The concept is simple in theory, but in practice the configuration of station piping is not. Station piping layouts become more complex as the tanks at a pipeline terminal facility become more numerous. Configurations of station piping necessary to accommodate a given number of tanks and to provide flexibility in routing multiple products in and out of those tanks provide many possibilities for the creation of pipeline interface material. Each pipeline facility is different, not only among pipeline companies but within pipeline companies. There is no way to predict how easy or hard it will be to minimize possible sulfur contamination of ULSD in station piping, except to examine the risks on a case-by-case basis. In fact, the interface generation in station piping and breakout tanks may be even more important than during pipeline transit. The volume of interface material thus generated is due to the physical attributes of the system. It has fewer variables but approaches being a fixed value on a barrel-per-batch, not a percentage, basis. For instance, one pipeline operator may create 25,000 barrels of high-sulfur/low-sulfur distillate interface per batch whether the batch is 250,000 barrels or 1,000,000 barrels. In addition, a given batch of product might be transported in multiple pipelines between its origin and its final destination and even within the same system might require a stop in breakout tanks, as noted above. Each segment of the journey generates additional interface.

3.1.5 Slack Line and Open Channel Flow

Generally most pipelines flow full with no vapor space or a free liquid surface. However, under certain topographic conditions with drastic elevation changes, we may encounter pipeline sections that are partially full, called open channel flow or slack line conditions. Slack line operation may be unavoidable in some water lines, refined product and crude oil pipelines. Such a flow condition cannot be tolerated with high vapor pressure liquids and in batched pipelines. In the latter there would be intermingling of batches with disastrous consequences. Consider a long pipeline with a very high peak at some point between the origin A and the terminus B as shown in figure. Due to the high elevation point at C, the pressure at A must be sufficient to take care of the friction loss between A and C, and the pressure head due to elevation difference between A and C, and the minimum pressure required at the top of the hill at C to prevent vaporization of liquid. Once the liquid reaches the peak at C with the required minimum pressure, the elevation difference between C and B helps the liquid gain pressure as it flows down the hill from C to the terminus at B. The frictional pressure drop between C and B has an opposite effect to the elevation and hence the resultant pressure at the terminus B will be the difference between the elevation head and the friction head. If the elevation head between C and B is sufficiently high compared with the frictional pressure drop between C and B, the final delivery pressure at B will be higher than the minimum required at the terminus. If the delivery at B is into an atmospheric storage tank, the hydraulic gradient will be modified as shown in the dashed line for slack line conditions

The upper hydraulic gradient depicts a packed line condition where the delivery pressure at B represented by point F is substantially higher than that required for delivery into a tank represented by point G. The lower hydraulic gradient shows that a portion of the pipeline between the peak at C and a point D will run in a partially full or slack line condition. Every point in the pipeline between C and D will be at zero gauge pressure. From D to B the pipe will run full without any slack. The slack line portion CD of the pipeline where the pipe is only partially full of the liquid is also referred to as open channel flow.

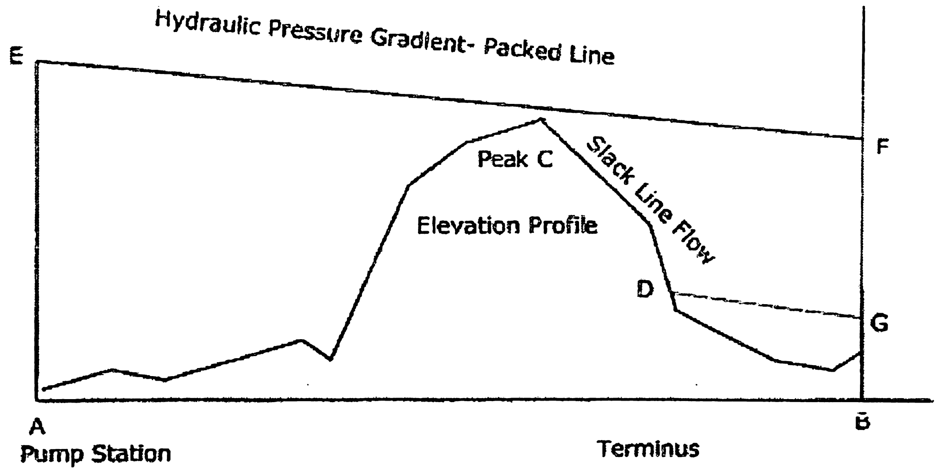

Fig 3.2: Hydraulic gradient: slack line versus packed line.

In this portion of the pipeline both liquid and vapor exists, which is an undesirable condition especially when pumping high vapor pressure liquids. Since a minimum pressure has to be maintained at the peak C, to prevent vaporization, the subsequent open channel flow in section CD of the pipeline defeats the purpose of maintaining a minimum pressure in the pipeline. In such instances, the pipeline must be operated in a packed condition (no slack line or open channel flow) by providing the necessary back pressure at B using a control valve, thus bringing the hydraulic gradient back to EF. The control valve at B should have an upstream pressure equal to the pressure that will produce the packed line hydraulic gradient showed in figure. In crude oil and refined product pipelines where a single product is transported, slack line can be tolerated. However, if the pipeline is operated in batched mode with multiple products flowing simultaneously, slack line cannot be allowed since intermingling and consequently degradation of the different batches would occur. A batched pipeline must therefore be operated as a tight line by using a control valve to create the necessary back pressure to pack the line. The back pressure valve would maintain the upstream pressure corresponding to point F on the hydraulic gradient. Downstream of the valve the pressure would be lower for delivery into a storage tank.

3.2 LOOPING

The process of paralleling of an existing pipeline by another pipeline over the whole length or any part of it to increase capacity and efficiency.

A pipe loop is a length of parallel pipe installed between two points on a main pipeline as shown in Figure. The purpose of the pipe loop is to split the flow through a parallel segment of the pipeline between the two locations, resulting in a reduced pressure drop in that segment of the pipeline. Consider pipeline from A to B with a loop installed from C to D as shown in Figure. The flow rate between A and C is 6000 gal/min. At C where the loop is installed the flow rate of 6000 gal/min is partially diverted to the loop section with the remainder going through the mainline portion CD. If we assume that the diameter of the loop is the same as that of the main pipe, this will cause 3000 gal/min flow through the loop and an equal amount through the mainline. Assume that the section CD of the mainline prior to looping with the full flow of 6000 gal/min flowing through it had a resulting pressure drop of 25 psi/mile. With the loop installed, section CD has half the flow and therefore approximately one-fourth of the pressure drop (since the pressure drop varies as the square of the flow rate) or 6.25 psi/mile. If the length CD is 10 miles, the total frictional pressure drop without the loop will be 250 psi. With the pipe loop the pressure drop will be 62.5 psi, which is a significant reduction. Therefore if a pipeline section is bottlenecked due to maximum allowable operating pressure, we can reduce the overall pressure profile by installing a loop in that pipe segment.

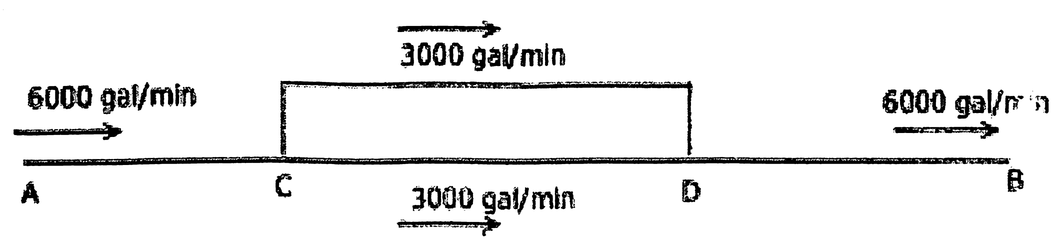

Fig 3.3: looping in a pipeline.

What would be the impact if the looped section of pipe were smaller than the mainline?

If we install a smaller pipe in parallel, the flow will still be split through the loop section but will not be equally divided. The smaller pipe will carry less flow rate than the larger mainline pipe, such that the pressure drop through the mainline from point C to point D will exactly equal the pressure drop through the pipe loop between C and D, since both the mainline pipe and the pipe loop have common pressures at the junction C and D.

This method is not possible for a product pipeline as the Reynolds number changes. The Reynolds number in the case of a product pipeline has to be greater than 4000 (i.e.) turbulent flow has to be maintained. So this case is ruled out.

3.3 Liquid Pipeline Drag Reducers

Drag reduction is the process of reducing the pressure drop due to friction in a pipeline by continuously injecting a very small quantity (parts per million, or ppm) of a high-molecular-weight hydrocarbon, called the drag reduction agent (DRA), into the flowing liquid stream. When injected into the pipeline these long chain polymers interact with small scale flow disturbance that develop into large scale turbulent structures. These interactions interfere with the development of large scale turbulent flow structures resulting in a reduction in the amount of turbulent flow in the pipe. This reduction in turbulence results in a reduction in the frictional pressure loss for a given flow rate. Drag reduction is defined as the reduction in the friction pressure loss of a DRA treated commodity when compared to the untreated commodity and it is typically expressed a percent. The long chain polymer DRA's are broken up in regions of flow where high shear is present such as pumps or through pipe section with numerous elbows. Once broken up these types of DRA no longer exhibit any significant drag reduction. There are new types of DRA which are able to reform after passing through regions of high shear. These types of DRA do exhibit drag reduction effects after regions with high shear flow.

The DRA is effective only in pipe segments between two pump stations. It degrades in performance as it flows through the pipeline for long distances. It also completely breaks up or suffers shear degradation as it passes through pump stations, meters and other restrictions. DRA works only in turbulent flow and with low-viscosity liquids. Thus, it works well with refined petroleum products (gasoline, diesel, etc.) and light crude oils. It is ineffective in heavy crude oil pipelines, particularly in laminar flow. To determine the amount of drag reduction using DRA we proceed as follows. If the pressure drops due to friction with and without DRA are known, we can calculate the percentage drag reduction:

$$\textbf{Percentage Drag Reduction} = 100*(DP_0-DP_1)/DP_0$$

Where

DP_0 = Friction drop in pipe segment without DRA, psi

DP_1 = Friction drop in pipe segment with DRA, psi

The above pressure drops are also referred to as untreated versus treated pressure drops. It is fairly easy to calculate the value of untreated pressure drop, using the pipe size, liquid properties, etc. The pressure drop with DRA is obtained using DRA vendor information. In most cases involving DRA, we are interested in calculating how much DRA we need to use to reduce the pipeline friction drop, and hence the pumping horsepower required. It must be noted that DRA may not be effective at the higher flow rate, if existing pump and driver limitations preclude operating at higher flow rates due to pump driver horsepower limitation. Consider a situation where a pipeline is limited in throughput due to maximum allowable operating pressures (MAOP). Let us assume the friction drop in this MAOP limited pipeline is 800 psi at 100,000 bbl/day. We are interested in increasing pipeline flow rate to 120,000 bbl/day using DRA and we would proceed as follows:

Flow improvement desired = (120,000-100,000)/100,000= **20%**

If we calculate the actual pressure drop in the pipeline at the increased flow rate of 120,000 bbl/day (ignoring the MAOP violation) and assume that we get the following pressure drop:

Frictional pressure drop at 120,000 bbl/day = 1150 psi

And

Frictional pressure drop at 100,000 bbl/day = 800 psi

The percentage drag reduction is then calculated as

Percentage drag reduction = 100(1150-800)/1150 = **30.43%**

In the above calculation we have tried to maintain the same frictional drop (800 psi) using DRA at the higher flow rate as the initial pressure-limited case. Knowing the percentage drag reduction required, we can get the DRA vendor to tell us how much DRA will be required to achieve the 30.43% drag reduction, at the flow rate of 120,000 bbl/day. If the answer is 15 ppm of Brand X DRA, we can calculate the daily DRA requirement as follows:

Quantity of DRA required= (15/106)(120,000)(42)=75.6 gal/day

The quantity of DRA required will depend on the pipe size, liquid viscosity, flow rate, and Reynolds number, in addition to the percentage drag reduction required. Most DRA vendors will confirm that drag reduction is effective only in turbulent flow (Reynolds number>4000) and that it does not work with heavy (high-viscosity) crude oil and other liquids. Also, drag reduction cannot be increased indefinitely by injecting more DRA. There is a theoretical limit to the drag reduction attainable. For a certain range of flow rates, the percentage drag reduction will increase as the DRA ppm is increased. At some point, depending on the pumped liquid, flow characteristics, etc., the drag reduction levels off. No further increase in drag reduction is possible by increasing the DRA ppm.

3.3.1 Why we use DRA?

DRA has typically been used to cater for those occasional instances when more oil is produced than can be physically pumped down the line, given the pipeline dimensions and pressure constraints available. However. Drag Reduction is rapidly becoming an essential aspect of cost savings. Pipelines are built with a life expectancy of about 20 years (wall thickness, materials and corrosion rate calculations all taken into account). But replacing pipelines is a very expensive pastime (up to $50 million for 100 km). Clearly, if replacing pipelines can be postponed for as long as possible, there are enormous savings in store. Over time pipelines corrode, no matter how well you look after them (regular pigging, cathodic protection, injecting corrosion inhibitors, etc.). As the wall thickness reduces, so does the Maximum Allowable Operating Pressure (MAOP). If we continue to operate a line at high pressures but the wall thickness has reduced, there is a risk of pipeline rupture. Hence, there are 3 choices:

- Renew the line (very costly)
- Reduce your pressure and hence flow (deferment = very costly)
- Inject Drag Reducer (enables equal flows at lower pressures = low cost)

If the MAOP has been reduced to maintain integrity of the system, the amount of oil we can pump through that line must reduce. This can cause deferment in the worst case. However, by injecting Drag Reducer, the same quantity of oil can be pumped, but at a lower pressure. The drag of the oil on the pipeline is reduced, and thus the pressure drop between the two ends of the node is reduced. Thus, careful monitoring of the line, the complete line renewal can be postponed, and the massive investment can be postponed by perhaps several years.

Drag Reducing Agent (DRA) comes in both liquid and gel form. DRA can be directly injected into the Main Oil Line (MOL), downstream of the oil export pumps

3.3.2 In which instances is DRA used?

DRA was initially used only for "peak shaving." This means that during normal operations, no DRA is injected. However, under pump-down conditions DRA would be injected to enable extra flow of oil through a given pipeline with a limited MAOP. This typically occurs following a MOL shut down. A MOL shut down does not necessarily imply deferment. The stations along the MOL mostly have some form of storage tanks and as such can continue producing without pumping into the MOL. They produce to their tanks. Following the shut down, the MOL coordinator then agrees with the Areas who will empty their tanks first and temporarily increase their section of MOL flow. This may only be possible with the use of DRA. DRA can however be used as described above, to postpone the replacement of an existing pipeline whose MAOP is decreasing (due to corrosion). Thus it can be seen that DRA has 2 uses:

• To increase the flow of oil through an unchanged MAOP

• To maintain a flow rate through a line where MAOP has been reduced due to corrosion

3.3.3 Advantages of DRA

Capacity may be increased by installing more pumping power on the pipeline system, by installing parallel pipes section or by increasing the diameter of the mainline pipe. The installation of new pumping facilities or additional pipe is capital investment and is a time consuming process. A DRA injection installation, in its simplest form, consists of an injection tap, an injection pump, and a DRA storage tank. This typically requires a much smaller capital investment and can be quickly installed at almost any existing facility. The DRA injection equipment can also be easily relocated to other locations, in case operational needs in the future. Since DRA injection equipment can be deployed quickly, it can be used to provide short term increase in capacity if required. DRA can be used selectively. It can be injected into specific commodities and at specific rates to meet the required goals of increased capacity and improved operating costs.

3.3.4 Disadvantages of DRA

Unlike other methods of increasing capacity such as increasing pumping power or increasing the effective pipe diameter, the increase in capacity is gradual as the DRA is injected into the pipe segment. The full effect of DRA in a pipe segment is not realized until all the fluid in the pipe segment contains the required concentration of DRA. DRA is destroyed when it passes through high shear devices like pump and therefore must be injected in every pipe section between pump stations if the benefits of using DRA are required. DRA is only suitable for pipe sections where the frictional pressure loss is significant and provides no significant benefits in pipe section where primary losses are gravitational losses. With deregulation in the energy sector and real time negotiation of energy costs optimizing the uses of DRA in term of locations, injection rates, and scheduling may become quite difficult. The use of DRA may not be allowed in certain products such as aviation fuel so commodity scheduling may need to change to avoid potential contamination.

3.3.5 DRA Which Can Be Used For Flow Improvement

3.3.5 Product name: LP Arctic Grade Flow Improver

LP Arctic Grade Flow Improver is used widely by many pipeline companies to increase the flow rate. The adaptability of the product in all climatic condition is one of the main advantages. The long chain polymer easily mingles with product to increase the turbulence in the flow.

Description of the flow improver LP Artic is given below.

Table 3.4: Product Data Sheet

GENERAL	
Designed For Use On	Petroleum Products
Flow Improver type	Suspension
Carrier/Solvent	Primary alkyl alcohol
PERFORMANCE	
Maximum drag reduction	Greater than 80%
Typical concentration	5 to 50 ppm
PROPERTIES	
Color	White
Density	7.3 lbs/gal (0.88 g/cm3
Flash Point	>175°F (>79°C)
Viscosity	145 - 150 cP @ 511s-1 (Non-Newtonian)
Freezing Point	-60°F (-51°C)
Vapor Pressure	0.02 psi @ 100°F
HANDLING	
Operating range	-40°F to 90°F (-40°C to 32°C)
Product stability	Very stable suspension Intermittent agitation recommended
Heating	Not required
INJECTION EQUIPMENT	
Pumps	Various designs available for different injection range and environments
Range	5 to 2,500 gal/day (20 to 9,500 L/day)
Flow meter	Mass (Coriolis)
Automation	Available
SAFETY AND ENVIRONMENTAL	
Safety	Low hazard Combustible, non-flammable liquid
Health	Low toxicity. Conventional protection equipment
Environmental	Non-hazardous waste as per Environmental Protection Agency

3.3.5.2 Performance graph using the product

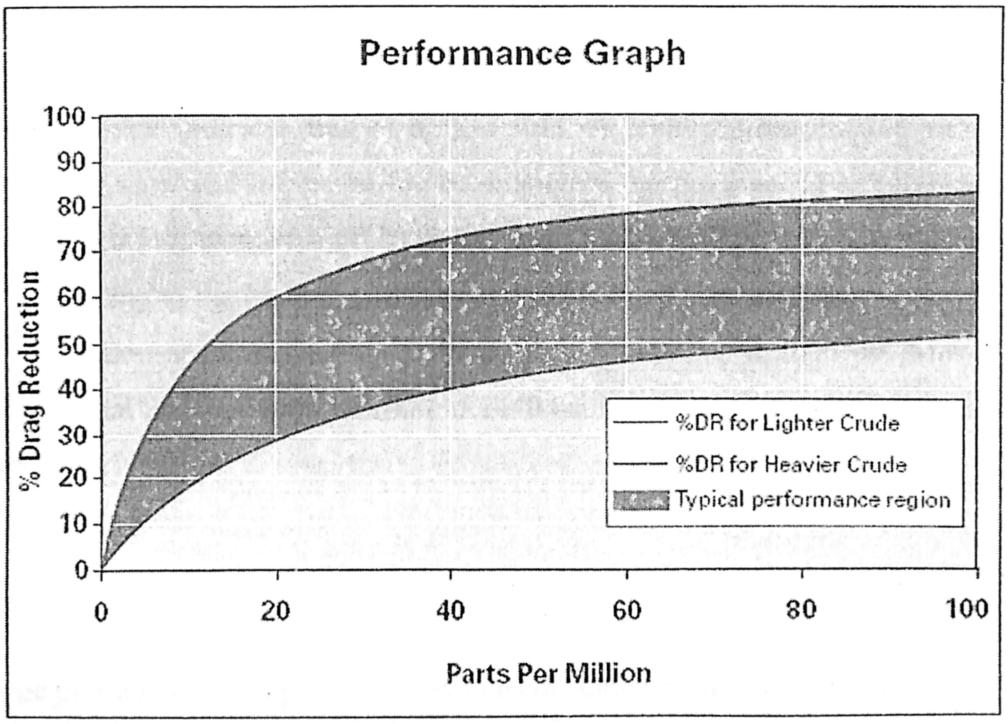

FIG 3.5: PERFORMANCE GRAPH

3.3.6 COST ANALYSIS ON DRA

Cost of DRA depends upon the amount that is added to the required section and length of the section. It is almost estimated that injection along the length of the pipeline at a combined cost of less than \$0.13 per incremental barrel represented a return on investment of 5:1.

Cost of DRA Rs 5.2/barrel of product obtained.

Cost of equipments and labor involved in the entire process (app)	=Rs 35000
Cost of Petrol per barrel (app)	=Rs 7473
Cost of DRA per barrel of petrol	=Rs 5.2
Therefore cost incurred upon usage of DRA	= Rs 47.45*

* This cost includes the amount considered for equipments and labor also.

In general for all products the amount increased per liter is almost Rs 0.38 to 0.65

3.4 PUMPING STATION

In long pipelines the total pressure required to pump the liquid is provided in two or more stages by installing intermediate booster pumps along the pipeline. Taking an example calculation which indicates that at a flow rate of 5000 gal/min, a 100 mile pipeline requires a pressure of 2000 psi at the beginning of the pipeline. This 2000 psi pressure may be provided in two steps of 1000 psi each or three steps of approximately 670 psi each. In fact, due to the internal pressure limit of the pipe, we may not be able to provide one pump station at the beginning of the pipeline, operating at 2000 psi. Most pipelines have an internal pressure limit of 1000 to 1440 psi based on pipe wall thickness, grade of steel, etc.

In the example case with a 2000 psi requirement and 1400 psi pipeline MAOP, we would provide this pressure as follows. The pump station at the start of the pipeline will provide a discharge pressure of 1000 psi, which will be consumed by friction loss in the pipeline and at some point (roughly halfway) along the pipeline the pressure will drop to zero. At this location we boost the liquid pressure to 1000 psi using an intermediate booster pump station. We have assumed that the pipeline is essentially on a flat elevation profile. This pressure of 1000 psi will be sufficient to take care of the friction loss in the second half of the pipeline length. The liquid pressure will reduce to zero at the end of the pipeline. Since the liquid pressure at any point along the pipeline must be above the vapor pressure of the liquid at the flowing temperature, and the intermediate pumps require certain minimum suction pressure, we cannot allow the pressure at any point to drop to zero. Accordingly, we will locate the second pump station at a point where the pressure has dropped to a suitable suction pressure, such as 50 psi. The minimum suction pressure required is also dictated by the particular pump and may have to be higher than 50 psi, to account for any restrictions and suction piping losses at the pump station. For the present, we will assume 50 psi suction pressure is adequate for each pump station. Hence, starting with a discharge pressure of 1050 psi (1000+50) we will locate the second pump station (intermediate booster pump) along the pipeline where the pressure has dropped to 50 psi. This pump station will then boost the liquid pressure back up to 1050 psi and will deliver the liquid to the pipeline terminus at 50 psi. Thus each pump station provides 1000 psi differential pressure (discharge pressure minus suction pressure) to the liquid, together matching the total pressure requirement of 2000 psi at 5000 gal/min flow rate. In the above analysis we ignored pipeline elevations and assumed that the pipeline profile is essentially flat. With elevations taken into account, the location of the intermediate booster pump will be different from that of a pipeline along a flat terrain

Hydraulic balance is when each pump station supplies the same amount of energy to the liquid. Ideally pump stations will be located at hydraulic centers. This will result in the same horsepower (HP) being added to the liquid at each pump station. For a single flow rate at the inlet of the pipeline (no intermediate injections or deliveries), the hydraulic centers will also result in the same discharge pressures at each pump station. Due to topographic conditions it may not be possible to locate the intermediate pump station at the locations desired for hydraulic balance. For example, calculations may show that three pump stations are required to handle the flow rate and that the two intermediate pump stations are to be located at milepost 50 and milepost 85. The location of milepost 50, when investigated in the field, may be found to be in the middle of a swamp or a river. Hence we will have to relocate the pump station to a more suitable location after field investigation. If the revised location of the second pump station were at milepost 52, then obviously hydraulic balance would no longer be valid. Recalculations of the hydraulics with the newly selected pump station locations will show hydraulic imbalance and all pump stations will not be operating at the same discharge pressure or providing the same amount of HP to the liquid at each pump station. However, while it is desirable to have all pump stations balanced, it may not be practical. Balanced pump station locations afford the advantage of using identical pumps and motors and the convenience of maintaining a common set of spare parts (pump rotating elements, mechanical seal, etc.) at a central operating district location.

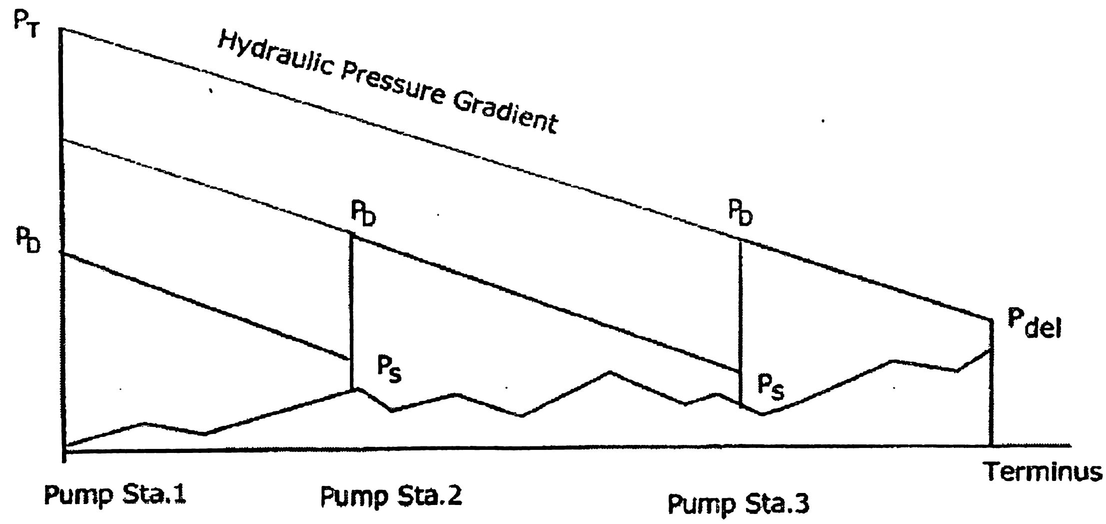

Figure 3.6 Hydraulic gradient: multiple pump stations.

Figure 3.6 shows a pipeline with varying elevation profile but no significant controlling peaks along the pipeline. The total pressure P_T was calculated for the given flow rate and liquid properties. The hydraulic gradient with one pump station at the total pressure PT is as shown. Since P_T may be higher than the pipe MAOP, we will assume that three pump stations are required to provide the pressures needed within MAOP limits. Each pump station will discharge at pressure P_D. If P_S represents the pump station suction pressure and P_{del} the delivery pressure at the pipeline terminus, we can state the following, using geometry:

$$P_D + (P_D - P_S)+(P_D - P_S)= P_T \quad (3.1)$$

Since the above is based on one origin pump station and two intermediate pump stations, we can extend the above equation for N pump stations as follows:

$$P_D + (N-1) * (P_D - P_S)= P_T \quad (3..2)$$

Solving for N we get

$$N= (P_T - P_S)/(P_D - P_S) \quad (3.3)$$

Equation (3.3) is used to estimate the number of pump stations required for hydraulic balance given the discharge pressure limit P_D at each pump station. Solving Equation (3.3) for the common pump station discharge pressure,

$$P_D= (P_T-P_S)/N+P_S \quad (3.4)$$

Cost of constructing a new pumping station including

Labour, cost of land and equipment charge. = 16646 lakhs (approx)

In this case there is no requirement of increasing the pumping station as the current pressure requirement is easily met by single pumping station. The cost of increasing the pumping station is too high.

This case is ruled out.

CHAPTER -4
EXPERIMENTS
&
COMPUTATIONS

4.1 CALCULATION OF CURRENT STATUS

- **Quantity of product** = 1.721 MMTPA

$Q = 1.721*10^6$	[Tonnes /annum]
$Q = (1.721*10^6 *10^3) / 8000$	[kg/hr]
$Q = (1.721*10^6 *10^3) / (8000*850)$	[m^3/hr]
$Q = 253.088$	[m^3/hr]

Q = Area * Velocity	
$A = (\pi / 4) * D^2$	
D = 0.3932	[m]
$A = (\pi / 4) * 0.3932$	
= 0.12143	[m^2]
V = (253.088 / 0.12143)	[m / hr]
V = 0.57895	[m / sec]

- **Reynolds Number**

$Re = (V * D) / (\nu)$

$= (0.57895 * 0.3932) / (10^{-6})$

$= 227643.14$

Turbulent Flow

- **Friction factor**

$(1 / \sqrt{f}) = -2 \log [(e/3.7D) + (2.51/ (R\sqrt{f}))$

$(1 / \sqrt{f}) = 7.894$

$f = 0.01602$

- **Darcy-Weisbach Equation for Head Loss**

$h_f = (flv^2) / (2gd)$

$= (0.01602 * 660000 * 0.57895^2) / (2 * 9.81 * 0.3932)$

$= 459.384$ [m]

- **Station Discharge Head**

S.D.H = h_f + Elevation head + Delivery head

Elevation Head = 176.5 – 44.6 = 131.9 [m]

= 459.384 + 131.9 + 20

= 611.28 [m]

- **Maximum Allowable Operating Pressure (MAOP)**

MAOP = (S * 2T * S.F) / D

= (2 * 0.252 * 60000 * 0.72) / 16

= 1360.8 psi

= 95.64 [kg / m^2]

= ($95.64*10^4$) / 850 [m]

= 1125.1765 [m]

S.D.H < M.A.O.P

Only one pumping station is required.

- **Horse Power Required**

= (Q * H * Sgr) / (367.46 * $\eta_1 * \eta_2$)

= (253.088 * 611.28 * 850) / (75 * 0.8 * 0.85 * 3600)

= 716.24 [Hp]

Number Of Pumps Used = (Horse Power Required / Horse Power of the Pump)

= (716.24 / 360) ≡ 2

Horse Power of the Pump used currently = 360 Hp

Number of Pumps Used currently = 2

- **Pressure Drop Due to Friction**

$P = (6.2475 * 10^{10} * f * Q^2 * S_g) / D^5$

$= (6.2475 * 10^{10} * 0.0156 * 253.088^2 * 0.85) / (393.6^5)$

P = 5.768 [KPa/Km]

= 0.0416 [(Kg/cm^2) / Km]

= 0.5915 [psi / Km]

For the entire 660 km of pipeline

= 390.39 [psi]

4.2 INCREASE IN THROUGHPUT QUANTITY BY 13% OF ACTUAL FLOW

- **Quantity of product** = 1.94473 MMTPA

$Q = 1.94473 * 10^6$	[Tonnes /annum]
$Q = (1.94473 * 10^6 * 10^3) / 8000$	[kg/hr]
$Q = (1.94473 * 10^6 * 10^3) / (8000*850)$	[m^3/hr]
$Q = 285.9897$	[m^3/hr]

Q = Area * Velocity

$A = (\pi / 4) * D^2$

$D = 0.3932$	[m]
$A = (\pi / 4) * 0.3932$	
$= 0.12143$	[m^2]
$V = (285.9897 / 0.12143)$	[m / hr]
$V = 0.6542$	[m / sec]

- **Reynolds Number**

  $Re = (V * D) / (\nu)$

  $= (0.6542 * 0.3932) / (10^{-6})$

  $= 257231.44$

Turbulent Flow

- **Friction factor**

  $(1 / \sqrt{f}) = -2 \log [(e/3.7D) + (2.51 / (R\sqrt{f}))$

  $(1 / \sqrt{f}) = 7.9655$

  $f = 0.01576$

- **Darcy-Weisbach Equation for Head Loss**

  $h_f = (flv^2) / (2gd)$

  $= (0.01576 * 660000 * 0.6542^2) / (2 * 9.81 * 0.3932)$

  $= 577.04$ [m]

- **Station Discharge Head**

  S.D.H = h_f + Elevation head + Delivery head

Elevation Head = 176.5 – 44.6 = 131.9 [m]

= 577.04+ 131.9 + 20

= 728.94 [m]

➢ **Maximum Allowable Operating Pressure (MAOP)**

MAOP = (S * 2T * S.F) / D

= (2 * 0.252 * 60000 * 0.72) / 16

= 1360.8 psi

= 95.64 [kg / m^2]

= (95.64*10^4) / 850 [m]

= 1125.1765 [m]

S.D.H < M.A.O.P

Only one pumping station is required.

➢ **Horse Power Required**

= (Q * H * Sgr) / (367.46 * $\eta_1 * \eta_2$)

= (285.9897 * 728.94 * 850) / (75 * 0.8 * 0.85 * 3600)

= 965.135 [Hp]

Number Of Pumps Used = (Horse Power Required / Horse Power of the Pump)

= 965.135 / 360

≡ 3

Proposed horse power of pumps = (360 * 2) + 250 = 970 Hp

➢ **Pressure Drop Due to Friction**

$P = (6.2475 * 10^{10} * f * Q^2 * S_g) / D^5$

$= (6.2475 * 10^{10} * 0.0156 * 285.9897^2 * 0.85) / (393.6^5)$

P = 7.246 [KPa/Km]

= 0.07151 [(Kg/cm^2) / Km]

= 1.0168 [psi / Km]

For the entire 660 km of pipeline

= 671.088 [psi]

4.3 INCREASE IN THROUGHPUT QUANTITY BY 20% OF ACTUAL FLOW

- **Quantity of product** = 2.0652 MMTPA

$Q = 2.0652*10^6$	[Tonnes /annum]
$Q = (2.0652*10^6 *10^3) / 8000$	[kg/hr]
$Q = (2.0652*10^6 *10^3) / (8000*850)$	[m^3/hr]
$Q = 303.705$	[m^3/hr]

Q = Area * Velocity

$A = (\pi / 4) * D^2$

$D = 0.3932$	[m]
$A = (\pi / 4) * 0.3932$	
$= 0.12143$	[m^2]
$V = (303.705 / 0.12143)$	[m / hr]
$V = 0.6947$	[m / sec]

- **Reynolds Number**

$Re = (V * D) / (\nu)$

$= (0.6947 * 0.3932) / (10^{-6})$

$= 273156.04$

Turbulent Flow

- **Friction factor**

$(1 / \sqrt{f}) = -2 \log [(e/3.7D) + (2.51/ (R\sqrt{f}))$

$(1 / \sqrt{f}) = 0.125$

$f = 0.0156$

- **Darcy-Weisbach Equation for Head Loss**

$h_f = (flv^2) / (2gd)$

$= (0.0156* 660000 * 0.6947^2) / (2 * 9.81 * 0.3932)$

$= 644.09$ [m]

- **Station Discharge Head**

S.D.H = h_f + Elevation head + Delivery head

Elevation Head = 176.5 – 44.6 = 131.9 [m]

= 644.09 + 131.9 + 20

= 795.99 [m]

- **Maximum Allowable Operating Pressure (MAOP)**

MAOP = (S * 2T * S.F) / D

= (2 * 0.252 * 60000 * 0.72) / 16

= 1360.8 psi

= 95.64 [kg / m^2]

= ($95.64*10^4$) / 850 [m]

= 1125.1765 [m]

S.D.H < M.A.O.P

Only one pumping station is required.

- **Horse Power Required**

= (Q * H * Sgr) / (367.46 * $\eta_1 * \eta_2$)

= (303.705 * 795.99 * 850) / (75 * 0.8 * 0.85 * 3600)

= 1119.195 [Hp]

Number Of Pumps Used = (Horse Power Required / Horse Power of the Pump)

= 1119.195 / 360

≡ 4

Proposed horse power of pumps = (360 * 2) + 400 = 1120 Hp

- **Pressure Drop Due to Friction**

$P = (6.2475 * 10^{10} * f * Q^2 * S_g) / D^5$

$= (6.2475 * 10^{10} * 0.0156 * 303.705^2 * 0.85) / (393.6^5)$

P = 8.0886 [KPa/Km]

= 0.07983 [(Kg/cm^2) / Km]

= 1.135 [psi / Km]

For the entire 660 km of pipeline

= 749.1 [psi]

CHAPTER -5
CONCLUSIONS
&
RECOMMENDATIONS

5.1 ANALYSIS ON WHICH IS FEASIBLE

TABLE 5.1: RESULT ANALYSIS

Method used for Augmentation	Capacity increased	Cost involved	Remarks
1. Looping	****	****	Looping not possible for product pipeline
2. Pumping station increase	****	****	One pumping station is sufficient as per calculation.
3. Modification in initial condition	• **Case 1 :** 13% increase	68 lakhs	• Cost effective. • Installation of a pump of 250 Hp • Cost in transporting: 174 Rs/MT
	• **Case 2:** 20% increase	115 lakhs	• Not preferred in long run. • Installation of a pump of 400 Hp • Cost in transporting: 186.34 Rs/MT
4. Drag Reducing Agent	Possible up to 15%	Rs 5.2 per incremental barrel obtained. Investment return of 5:1 ratio	• Not preferred in India. • Used only when demand is very high.

5.2 Recommendation and Discussion

Looping

Looping method is not possible as the Reynolds number changes in a product pipeline which results in mixing of products.

Drag Reducing Agent

Drag Reducing Agent can be used to increase the flow rate. DRA reduces the frictional pressure, thus flow rate increases according to the quantity of DRA added to the flow. Usage of DRA is not preferred in the long term process. According to product being sent, climatic condition, DRA is selected. This involves more research and development for long run. In India, DRA is used only to meet demand requirements.

Cost involved in using DRA is approximately Rs 0.38 to 0.65 per liter of product.

Pumping Station Increase

Another method of capacity augmentation is by increasing the number of pumping station. Pumping station can be increased if the pressure is not exceeding the MAOP. In NSPL, the design is in such a way that only one pumping station is required. So increasing the pumping station is not possible.

Modification of Initial Condition

Modification in initial condition is the final method of capacity augmentation .The current status of NSPL calculation is shown on the earlier stage.

MAOP	: 1360.8 psi
Horse power required	: 716.24 Hp
No of pumps used currently	: 2
Horse power of pump being used	: 360 Hp
Friction loss in 660 Km	: 390.4 psi

Case 1

Throughput is increased by 13%

Throughput : 1.94473 MMTPA

Horse power required : 965.135 Hp

Excessive Hp required as per new design: 250 Hp

Friction loss in 660 Km : 671.088 psi

Cost involved in transporting : 174 Rs/MT

Case 2

Throughput is increased by 20%

Throughput : 2.0652 MMTPA

Horse power required : 1119.195 Hp

Excessive Hp required as per new design: 400 Hp

Friction loss in 660 Km : 749.1 psi

Cost involved in transporting : 186.34 Rs/MT

Case 1 is taken as the best suggestion as the increase in Hp is 250. It can be compensated by installing another pump. In long run, the increase in pressure will not affect as much as in case 2. Cost involved in transporting is less in case 1.

13% increase of throughput is comparatively more feasible than 20% increase.

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