Enhancing the flexibility of pipeline infrastructure to cope with heavy oils: incremental thermal retrofit

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ABSTRACT

Pipelines that were well designed for conventional oils may not be able to cope with a transition to heavy oils without some retrofit adaptation, as the increased pressure drop may exceed constraints and force some reduction in throughput. In this paper, ways of enhancing the utilization of existing, capital intensive infrastructure by small, incremental additions are explored. A thermo-hydraulic pipeline model for a buried pipeline is presented. The model is then applied to a case study involving a section of the important, recently built Russia-China ESPO pipeline, for which a gradual shift from the current (design) light oil to heavier oils is considered. A number of thermal retrofit scenarios are proposed and assessed which involve the incremental supply of additional heat at selected points. These scenarios go from pre-heating of the oil at entrance to use of single and multiple intermediate heating stations. The heating duty requirements for each case are calculated. The results show that a careful use of such thermal management techniques can significantly mitigate the reduction in throughput that would

otherwise be required, leading to significant economic savings in operations. It is highlighted that the development of adaptable, modular low-cost heating technologies would make this approach significantly advantageous over other alternatives.

KEYWORDS: Crude oil, pipeline, modelling, transportation, drag reduction.

1. INTRODUCTION

Oil pipelines represent the most economical option to transport large amounts of oil over long continental distances. The hydraulic design of pipelines mainly takes into account pressure drop (ΔP) due to friction and ground elevation. Relevant design variables include throughput, operating temperature, environmental conditions and fluid properties expected in the foreseeable future [1]. Viscosity, which varies inversely with temperature, is the key physical property for design, determining line size, pumping stations spacing and required pumping capacity (hence capital and operating costs). The pressure drop by friction increases with decreasing temperature (due to increase in viscosity), and decreases with flowrate (except for very low throughputs, as in the case of very viscous oils [2]). Therefore, the maximum distance between pumping stations heavily depends on the flowrate and the viscosity (hence on temperature) of the fluid being transported and heat losses along the pipeline.

Depletion of conventional oil reservoirs is gradually leading to extraction of heavier oils. These oils are generally characterized by higher viscosity, density and content of heavy metals, nitrogen and sulfur [3, 4]. It is estimated that more than half of the recoverable oil resources are unconventional, with about 57% of those being some type of heavy or viscous oil [5]. In addition, the depletion of conventional sources is also leading to extraction in remote locations, many of them in cold regions (Alaska, Canada, Russia, deep oceanic waters) and even Arctic

locations, where pipelines are seasonally or permanently exposed to extreme cold conditions. Under those conditions, viscosity increases due to gradual cooling along the line and application of drag reduction methods may be required for very viscous oils.

The main techniques for drag reduction involve viscosity reduction [2]–[4]: thermal (heating), dilution, and water emulsion. Emulsion and dilution reduce viscosity by adding up to 30_{vol}% of water or other diluent, which lead to reduced oil throughput and require additional auxiliary facilities. Other alternatives, such as core annular flow, internal coatings, and drag reduction agents, represent promising technologies for cold flow transportation, but are still costly, and may present stability issues or limited applicability depending on the oil composition. Further development is required for most of those alternative technologies [4].

Thermal methods, on the other hand, are widely proven and permit fully using the pipeline capacity to transport oil, but require local or continuous heating. A typical heating strategy consists of maintaining the high temperature at which oil is produced and introduced into the pipeline by applying insulation (passive strategy, e.g. insulation layer, burial) and, in most cases, reheating at later locations. Examples of existing heated pipelines are Alyeska in Alaska [3], Chad-Cameroon [6, 7] (both with heating at pumping stations) and Mangala in India (with continuous heating along the entire length of the pipeline) [8].

Most drag reduction methods are conceived to be installed in new facilities. However, not many are suitable to retrofit existing infrastructures. In fact, although thermal strategies are generally considered viable for long, insulated pipelines with heating provided at pumping stations, recent works indicate that the development of new technologies applicable at intermediate locations can lead to significant increase of the length between pumping stations [7], reducing the high capital

cost of pipeline infrastructures. In this paper, intermediate point heating is considered as the means to adapt existing pipelines to transportation of heavier feedstock, with the objective of minimizing the loss in throughput.

About 87% of all unconventional oil resources, including tar sands, bitumen, heavy and extra-heavy oil, are located in Canada, Venezuela and Russia. The exploitation of these hydrocarbons is commercially well advanced in Canada and Venezuela. On the other hand, oil production in Russia in the past decades has been focused on light oils, and heavy oil and bitumen reserves remain almost unexploited [3]. As conventional sources deplete, this is inevitably leading to a shift in oil quality, with viscous oils becoming more important in the coming years. Russia has developed a huge pipeline network to export crude oil from Siberia and the Urals to Europe and to the Far East [9]. Export to the Far East has been recently achieved with the finalization of the Eastern Siberia–Pacific Ocean (ESPO) pipeline, providing an alternative exportation route with great economic and geopolitical importance [10, 11]. This pipeline allows transportation to Japan, Korea and especially to China, where oil can now be massively exported through the 953 km pipeline branch recently constructed between Skovorodino (Russia) and Daqin (China) [12]. This is an example of a new costly and long unheated pipeline through remote locations, seasonally exposed to very cold environment, and designed to transport light oil.

The adaptation of these infrastructures to transport similar large amounts of heavier feedstock is a challenging task that will be of paramount importance for the economic viability of heavy oil production. Changes in oil quality are difficult to foresee for the entire lifetime of a pipeline (typically decades). As a result, pipelines that originally were optimally designed (even overdesigned) may face problems if the feedstock varies significantly, and the pipeline itself may become a bottleneck to production. A plausible scenario, considered in this paper, is the

transition in crude oil feedstock towards heavier quality. The questions addressed are whether it is possible to use with the heavy oils the pipeline as originally designed for light oils, to quantify any reduction in throughput arising and decide if drag reduction techniques have to be retrofitted. The high capital cost of pipeline infrastructures makes the construction of new systems prohibitive and the re-utilization of existing infrastructure an unavoidable and challenging task.

Modelling tools have emerged as a powerful alternative to assist in design and retrofit of these infrastructures [2]. In addition, these tools can also assist in the control of the heating systems [13] to prevent flow stoppage or deposit formation. The evaluation of temperature and pressure drop profiles involves the simultaneous solution of momentum and energy balance equations along the length of the pipeline. For the correct evaluation of these profiles it is important to take into account the variation of the physical properties with local operating conditions. In addition, it is important to correctly evaluate heat losses, hence an adequate representation of the boundary condition (buried, subsea, over-ground) is essential [14].

When designing heating systems, temperature constraints must be taken into account [1]: i) upper temperature limit, imposed either by consideration of vapor pressure (to avoid partial vaporization at hot spots) or by the maximum allowable temperature of the metal wall of the pipe (given by metallurgy and construction); and ii) lower temperature limit, imposed either by the maximum viscosity for transportation (0.5 cP in South America [2] and 0.25 cP in Europe and North America [6]) or by the wax appearance temperature [15], if the oil also presents wax deposit formation problems.

In this paper, a thermo-hydraulic model of a buried, insulated pipeline is used to study a realistic pipeline section. The impact of changes in oil feedstock quality are analyzed and several thermal

retrofit options, including initial heating and intermediate single and multiple-point heating are evaluated. The trade-off between throughput losses and the required heating is quantified, and optimum locations for the heating stations are identified which minimize heating requirements.

2. MODELLING APPROACH

A radially and axial distributed model is used to describe the thermo-hydraulic behaviour of an insulated, unheated pipeline. It is composed of 4 spatial domains: tube-side, pipe wall, insulation layer, and losses to the environment (Figure 1). This modelling approach has been used elsewhere for shell-and-tube heat exchangers [16, 17]. The pipeline model is a modification of the tube model in that work. The advantages are the easy set-up of different configurations (e.g. insulation layers, boundary conditions), the modular construction of composite models (e.g. multiple section pipelines) and potential use to solve simulation as well as optimization problems.

2.1. Tube-side

For a homogeneous fluid (oil) flowing in a horizontal pipe (for simplicity ground elevation is neglected in the following), the pressure drop is mainly due to friction. The pressure drop on a differential element in the axial direction is:

$$-\frac{dP(z)}{dz} = \frac{1}{4R_{w,i}} f(z)\rho(z)u(z)^2 = \frac{2\tau_w(z)}{R_{w,i}} \quad \forall z \in (0, L] \tag{1}$$

where P is pressure, z the axial coordinate, f the friction factor, u the oil linear velocity, ρ the oil density, τ_w the wall shear stress, and $R_{w,i}$ is the pipe wall inner radius. Subscript w refers to the pipeline metal wall.

The energy balance is:

$$\rho(z)\frac{\partial e(z)}{\partial t} = -\rho(z)u(z)\frac{\partial e(z)}{\partial z} + \frac{2}{R_{w,i}}\left(-q"_{losses}(z) + q"_{fr}(z)\right) \quad \forall z \in (0, L] \tag{2}$$

$$q"_{losses}(z) = -h(z)\left(T_w|_{r=R_{w,i}}(z) - T(z)\right) \quad \forall z \in [0, L] \tag{3}$$

$$q"_{fr}(z) = \tau_w(z)u(z) \quad \forall z \in [0, L] \tag{4}$$

where e is the specific enthalpy of the oil, $q"_{losses}$ is the heat flux lost through the pipe inner surface, T is the oil temperature, T_w is the wall temperature, r is the radial coordinate, and $q"_{fr}$ the heat of friction, important for viscous oils and large and insulated pipelines [1].

The heat transfer coefficient, h, and the friction factor, f, are calculated as a function of the local conditions (at each z) using the Gnielinski and Petukhov correlations, respectively [18]. For the cases considered here, the flow regime is mainly turbulent. Oil physical properties are calculated using API relationships as function of oil characteristic parameters (API, kinematic viscosity at 38ºC ($\nu_{38°C}$), and mean average boiling point (MeABP)) and local bulk temperature [19]. The mass flowrate ($\dot{m}$) is:

$$\dot{m} = \pi R_{w,i}^2 \rho(z)u(z) \qquad \forall z \in [0, L] \tag{5}$$

2.2. Insulation layer and tube wall

The energy balance on a differential element of the insulation layer, neglecting axial effects and heat sources, is:

$$\rho_{ins}C_{p,ins}\frac{\partial T_{ins}(z,\ r)}{\partial t} = \frac{1}{r}\frac{\partial}{\partial r}\left(r\lambda_{ins}\frac{\partial T_{ins}(z,\ r)}{\partial r}\right) \quad \forall z \in [0, L], r \in (R_{ins,i}, R_{ins,o}) \tag{6}$$

where the subscript *ins* refers to insulation, C_p is the specific heat capacity and λ the thermal conductivity, both considered constant. The local heat flux is defined as:

$$q"_{ins}(z,r) = -\lambda_{ins}\frac{\partial T_{ins}(z,\ r)}{\partial r} \qquad \forall z \in [0,L], r \in [R_{ins,i}, R_{ins,o}] \tag{7}$$

Likewise, the energy balance and heat flux to the tube wall (subscript *w*) are:

$$\rho_w C_{p,w}\frac{\partial T_w(z,\ r)}{\partial t} = \frac{1}{r}\frac{\partial}{\partial r}\left(r\lambda_w\frac{\partial T_w(z,\ r)}{\partial r}\right) \forall z \in [0,L], r \in (R_{w,i}, R_{w,o}) \tag{8}$$

$$q"_w(z,r) = -\lambda_w\frac{\partial T_w(z,\ r)}{\partial r} \quad \forall z \in [0,L], r \in [R_{w,i}, R_{w,o}] \tag{9}$$

2.3. Losses to Environment for a Buried Pipeline

The modelling approach used permits considering alternative models for the losses to the environment depending on the location of the pipeline, including buried, over-ground continental or sub-sea pipeline, and other boundary conditions such as uniform wall temperature or uniform heat flux. For a buried pipeline, the local heat losses can be simply described using a conduction shape factor [18]:

$$q"_{env}(z) = \frac{\lambda_{gr}(T_{ins}|_{r=R_{ins,o}}(z) - T_{env})}{R_{ins,o}\cosh^{-1}(\delta/R_{ins,o})} \tag{10}$$

where $q"_{env}$ is the heat flux at the insulation outer surface, δ the distance from the ground surface to the pipe centre, T_{env} is the temperature of the environment (air), and $R_{ins,o}$ is the outer radius of the insulation layer.

More detailed models have been proposed to model the losses to the environment from buried pipelines [12, 20–22]. However, those are computationally expensive and more appropriate when the main subject of the study is the effect of a hot pipeline on the surroundings [23, 24]. Here, the use of a shape factor has been considered sufficient for the level of detail required in the present work. It should be noted that this approach neglects the thermal inertia of the ground surrounding

the pipeline, which might be important when considering weather seasonality and transients such as start-up and shutdown.

2.4. Boundary conditions

For the tube-side domain, temperature and pressure are fixed at the inlet (z = 0). Continuity in the radial direction is imposed for temperature between the wall-insulation domains, and for heat flux between the oil-wall, wall-insulation and insulation-environment domains.

$$T|_{z=0} = T_{in} \tag{11}$$

$$P|_{z=0} = P_{in} \tag{12}$$

$$q"_w|_{r=R_{w,i}} = q"_{losses} \tag{13}$$

$$q"_w|_{r=R_{w,o}} = q"_{ins}|_{r=R_{ins,i}} \tag{14}$$

$$T_w|_{r=R_{w,o}} = T_{ins}|_{r=R_{ins,i}} \tag{15}$$

$$q"_{env} = q"_{ins}|_{r=R_{ins,o}} \tag{16}$$

where subscripts *in* refers to inlet conditions, *i* to inner surface, and *o* to outer surface.

2.5. Multiple-section pipeline

A number of pipeline modules can be connected in series to represent intermediate processing, such as heating, pumping, or flow diversion. Similarly, various sections can have different insulation, diameter, buried depth or environment boundary condition. In this paper, the only intermediate change considered concerns temperature increase. The connection between pipeline sections j-1 and j is performed as follows:

$$T_{out,j-1} + \Delta T_{j-1} = T_{in,j} \tag{17}$$

$$P_{out,j-1} = P_{in,j} \quad (18)$$

$$\dot{m}_{j-1} = \dot{m}_{j} \quad (19)$$

where j is the section number and ΔT_{j-1} is the intermediate increase in oil temperature between section j-1 and section j. Subscript out refers outlet conditions.

2.6. Solution method

The model was implemented and all equations solved in a commercial simulation software[25]. The wall and insulation domains are discretized using a second order Centered Finite Discretization method with 10 points. A Backward Finite Discretization method with 100 points is used to discretize each pipeline section in the axial domain.

3. CASE STUDY: RETROFIT OF AN EXISTING PIPELINE TO TRANSPORT HEAVIER OILS

The pipeline considered is based on the China leg of the ESPO pipeline recently constructed to export oil from Russia to China. The pipeline parameters, extracted from various references [12, 23, 26], are shown in Table 1. The oil currently transported (ESPO oil) has very low viscosity [27], allowing transportation in cold conditions (the inlet temperature to the Chinese branch is between -6 ºC and 10ºC), despite the extreme external cold conditions in winter (-40ºC and below). The insulation in the original design for ESPO oil aims to prevent extreme cooling of the oil, which could lead to wax deposition or even complete blockage (the pour point of ESPO is -36ºC [27]).

A pipeline section between two pumping stations is considered of length (L_{ESPO}) = 300 km (the distance between pumping stations in Chinese territory is reported to vary between 250 and 300 km). Information necessary for the accurate calculation of the pressure drop, such as ground elevation, are largely unknown to the authors. The maximum allowable pressure drop (ΔP_{max}) is estimated using the model with the physical properties of the ESPO oil [27] (Table 2) and assuming a horizontal pipeline (i.e. the ground elevation is neglected), maximum flowrate (throughput), and worst-case cooling conditions (external temperature of -40ºC and inlet oil temperature of -6ºC). Under these conditions, ΔP_{max} is estimated to be 4.8 MPa. This value is below the Maximum Allowable Operating Pressure (MAOP), which typically is between 8 and 10 MPa for this type of infrastructure. Therefore the inlet pressure required to make up for the head losses due to friction is well within feasible limits for the ESPO oil.

It is of interest to evaluate a potential gradual change in oil quality, from ESPO oil to increasingly heavier Oils 1 to 4 (the properties of which have been extracted from available databases [28] and are given in Table 2), and the implication in respect of the throughput rate achievable for this pipeline. The kinematic viscosity vs. temperature behavior of the various oils, shown in Figure 2, indicates that Oils 1-4 are all much more viscous than ESPO at low temperatures. First, the options of inlet heating of the oil (before pumping) and flowrate reduction are considered for the heavier oils. Then, intermediate heating retrofits are explored to minimize throughput loss for the heaviest oils. The only temperature constraint considered is the maximum oil temperature given by the pipeline design, which is fixed at 90ºC (normally 80-100ºC). This will limit the temperature increase (ΔT) in the heating stations.

4. RESULTS

4.1. Effects of viscosity and inlet oil temperature on throughput

The temperature, viscosity and pressure drop along the pipeline section for the ESPO oil are shown in Figure 3. Over the 300 km, the temperature loss is only 5.9ºC and the exit temperature is -11.9ºC. The low viscosity of ESPO permits its transportation over long distances without requiring re-heating. As the oil becomes heavier than ESPO, the drag along the pipeline increases and cold flow (without additional heating) is no longer possible. For example, the maximum distance achievable for the given ΔP_{max} becomes only 38 km for cold flow (i.e. with inlet temperature of -6ºC and no heating) of Oil 1 (second column in Table 3). Assuming that the inlet pressure cannot be raised any further, inlet heating of the oil before pumping is the preferred thermal retrofit option, given that suitable facilities are likely to exist already or to be easily installed at the extraction and pumping terminals. For Oil 1, the temperature at the inlet must be raised to the maximum transportation value (90ºC) to maintain 100% throughput. The heat duty would depend on the thermal management strategy applied in sections upstream. The corresponding temperature, viscosity and pressure drop profiles achieved are shown in Figure 3. This retrofit solution (labelled HS0, for heat station 0) enables transportation at maximum throughput for oils with viscosity lower or equal to that of Oil 1.

For more viscous oils inlet heating is not enough and, if no other drag reduction techniques are applied, the only alternative is to reduce throughput. For example, with HS0 in place, the maximum length ($L_{(\Delta Pmax)}$) that Oil 3 can be transported (at maximum throughput, inlet heating to 90ºC and ΔP_{max} = 4.8 MPa) is 264 km (Figure 3 and Table 3). A reduction in throughput of 8.8% (equivalent to 1.32 Mtpa) enables transportation of this oil to the end of the 300 km

section. The results for the other oils, shown in Table 3, indicate that, with maximum inlet heating in HS0, a throughput reduction of 2.7% and 15.8% are required for Oils 2 and 4, respectively.

4.2. Intermediate heating to reduce throughput loss

Alternatively to reducing throughput, intermediate heating stations may be installed at key locations, increasing the length for which the oil can be transported for the maximum given pressure drop. In each intermediate heating station, the oil temperature is raised by a value ΔT to an outlet oil temperature not higher than 90ºC. The location of the heating stations, the heat duty (Q) required in each, and the number of intermediate heating points are some of the decision variables to consider for such intermediate heating retrofit options.

The main objective of the thermal retrofits is to maintain the original throughput, or at least minimize the loss of throughput. Ideally this should be achieved with a minimum heat input, which accounts for additional operating cost and environmental impact (from fuel combustion in fired heaters, generation of steam or electricity, etc.). Furthermore, this should be achieved with a minimum number and capacity of intermediate stations, which accounts for additional capital costs. In this section, a number of thermal retrofit options are evaluated, involving different amount of heat input, location, and number of heating stations. The number of stations and locations considered in the case study are represented in Figure 4, where L is the pipeline length (300 km) and fractions of L indicate the distance from the inlet to the location of the station (e.g. $L/3$ means a station located at 100 km from the inlet).

4.2.1. Single-point intermediate heating

Initially, a single-point heating at the midpoint of the line is considered (Case A). Figure 5 illustrates the impact of intermediate heating on temperature, viscosity and pressure drops for Oil 3. After inlet heating at HS0, a reduction of 8.8% in throughput was still required to meet the max pressure drop constraint. If additionally a single intermediate heating station (labelled HS1) is installed at the midpoint, with the oil reheated back to 90ºC, only a 4.5% reduction in throughput is needed, representing a significant additional throughput of 4.3% (0.645 Mtpa) with respect to the inlet heating case.

Restoring the oil temperature to the maximum value may not be the optimal option. Figure 6(a) shows the throughput losses vs. ΔT in the heating station HS1 for Case A and various oils. In the case of Oil 1, no intermediate heat input was required to maintain throughput, and therefore the HS0 option would be located at point (0, 0) in the plot. For heavier oils, as ΔT increases at the intermediate station, the throughput achieved increases accordingly. For Oil 2, a ΔT of 0ºC (no heating) corresponds to a throughput loss of 2.7%, as already noted. A ΔT of about 11ºC (a duty of 10.2 MW) in the midpoint station is enough to maintain maximum throughput. Further heating up to 90ºC is not necessary.

Although a proper techno-economic evaluation is required to evaluate the optimal case, maintaining throughput is clearly dominant in economic terms with respect to the cost of supplying additional heating. For illustration purposes, assuming heating entirely supplied by natural gas (with 100% efficiency) and Russian natural gas and average oil prices in October 2015[29], the fuel cost of intermediate heating is about $1.9m/yr per 10ºC increase, against a cost of $50.6m/yr for each 1% (equivalent to 0.150 Mtpa) of throughput lost. Therefore,

preserving throughput is clearly the priority in economic terms, although minimizing heating cost is not to be neglected when designing a retrofit system. The economic balance seems, a priori, very positive and indicates a fast return on the investment, although this would depend on the capital costs, i.e. on the particular heating technology used.

The previous analysis gives an idea of the optimal heat duty required for each oil type. However, if a gradual change in oil quality occurs, the heating system may need to be adapted. The arrows in Figure 6(a) indicate a potential adaptation pathway for Case A as the oil becomes progressively heavier. The installation of heating station HS0 at the inlet of the pipeline permits assuring transportation at full throughput as oil changes from ESPO to Oil 1. The installation of an additional single intermediate heating station HS1, providing an increase of 11ºC (Case A), is sufficient to handle a switch to oils from Oil 1 up to Oil 2. If no more retrofits are applied and the viscosity increases further to that of Oil 3, the loss in throughput increases from 0 to 5.4%. An upgrade of the intermediate station to deliver a greater ΔT will partially mitigate the reduction in throughput. A heat duty increase at the station by additional 3.7 MW (to reach the maximum oil temperature of 90ºC), reduces throughput losses to 4.5% (i.e. achieves a throughput increase of 0.9% or 0.135 Mtpa). This station cannot be further upgraded for heavier oils quality due to the maximum operating temperature constraint. After this second upgrade, the savings achieved with the heavier oils in terms of throughput are substantial compared to the base case (no intermediate heating). For instance, for Oil 4 the loss in throughput is reduced to 10.6% (1.59 Mtpa) compared to 15.8% (2.37 Mtpa) without intermediate heating.

The effect of the location of the intermediate heating station HS1 is shown in Figure 6(b) (Cases A-E). For Oil 2, maximum oil flowrate is achievable for all locations between C (at $L/4$ = 75 km) and E (at $3L/4$ = 225 km). Locations towards the start of the pipeline require smaller ΔT,

providing a more energy efficient heating option. The difference in ΔT is more noticeable beyond the pipeline midpoint (cases A, D and E), whilst locations in the first half of the pipeline (cases B and C) require similar ΔT. If the station is located at point B (at $L/3$ = 100 km) or C, maximum throughput can be restored with an increase of 8 or 7ºC (with duties of 7.4 MW or 6.5 MW), respectively. On the other hand, if the station is located at point D (at $2L/3$ = 200 km) or E, a temperature increase of 15.1 ºC or 20.6 ºC (duties of 14.0 MW or 19.1 MW) is required, respectively. This can be attributed to the non-linear impact of temperature on viscosity and, hence on drag and pressure drop.

For heavier oils (e.g. Oil 3 in Figure 6(b)) a single intermediate station is not sufficient, as discussed, and with the previous retrofits (HS0 and HS1) some throughput losses are inevitable. For the same throughput, HS1 locations closer to the inlet of the pipeline are more advantageous in terms of energy efficiency. However, for the same outlet temperature from the station (dash-dot line), a minimum in the throughput loss is observed for locations near the middle of the pipeline for both Oil 2 and Oil 3.

The location of the heating station should be chosen carefully if further change of the oil quality is expected. For instance, location C is the optimal retrofit option for Oil 2, since it enables full throughput to be achieved with minimum heat input. However, in this solution the crude oil is heated to the maximum allowable temperature. This would represent a bottleneck for later adaptation of the heating system to heavier oil, since no additional heat input is possible. On the other hand, options B or A could still be further retrofitted in a future upgrade with some extra duty if oils become heavier than Oil 2, to deliver greater ΔT and further reduce throughput loss. For this, the best options would be for the station to be near the middle point. Consequently, the optimal retrofit depends on: a) how fast the shift to heavier oils is expected to occur; b) how

pronounced this shift is expected to be; c) flexibility margins for future upgrade/retrofit. It should also be noted that the maximum allowable temperature is mainly determined by the pipeline construction and metallurgy. An upgrade of the pipeline in the heating station and its vicinity might allow heating above 90ºC. This option may entail additional capital costs and potential safety risks, which should be taken into account in addition to operating cost (fuel consumption) against the benefit of increasing throughput.

4.2.2. Multiple-point heating

In this section a plurality of intermediate heating stations are considered. For simplicity, heating stations are assumed to be uniformly distributed along the pipeline, with the required ΔT also equally distributed between them. Cases F and G in Figure 4 consider 2 and 3 intermediate heating stations, respectively. By introducing more than one heating point it is possible to maintain the oil at an average higher temperature (and hence relatively low viscosity) along the pipeline. An example is shown in Figure 7 for Oil 3, with 3 intermediate heating points (Case G) and the oil re-heated to the maximum temperature (90ºC) in each station. Results for Case A (single intermediate station at midpoint) are also shown in the figure for comparison.

The advantage of a multi-point system is the capability to supply greater heat duties without violating the maximum oil temperature constraint, by distributing the heating input between the various individual stations. This is shown in Figure 7. In Case A, the maximum ΔT at the intermediate station is 14.8ºC (for a duty Q = 13.9 MW), which is limited by the maximum oil temperature of 90ºC. In Case G, a ΔT of 7.4ºC (a duty Q = 7.1 MW) per station can be supplied without violating the constraint, which in cumulative terms equals to a total ΔT of 22.3ºC (total duty Q = 21.3 MW). As a result, in Case G the average viscosity along the pipeline is lower, and

oil temperature higher than in Case A, resulting in lower throughput losses. Figure 8 shows this in a slightly different way, by plotting the loss in throughput against the total ΔT (sum of ΔT at individual stations) for Oil 3, with 1, 2 and 3 intermediate heating stations (cases A, F, G). The lines corresponding to the three cases almost overlap. This indicates that a ΔT delivered by a station at the middle point (Case A) and the same ΔT uniformly distributed between several points around the centre lead to the same savings in throughput. For instance, a total ΔT of 14.8ºC concentrated at the middle point (maximum rise for Case A) reduces the throughput loss to 4.5%. If this total ΔT is distributed in 3 stations (case G), e.g. with a temperature rise of 4.9ºC per station (less than the maximum that could be applied), the impact on throughput is the same.

Table 4 summarizes the minimum throughput losses achievable for each of the oils and the retrofit options considered so far. Table 5 summarizes the total ΔT and Q for 1, 2 and 3 intermediate stations and the minimum throughput losses in Table 4. It should be noted that higher ΔT does not imply greater Q necessarily, since the latter depends on the throughput (flowrate) too.

The incremental improvement in throughput is smaller as the number of stations increases. A larger number of stations would also lead to greater capital and maintenance cost, not taken into account in this study, hence there is an optimization opportunity.

4.3. Retrofit heating strategy and requirements of potential heating technology

The results show that the best heating retrofit depends on the oil type. Single intermediate point heating is sufficient for the pipeline system to handle medium viscosity oils (e.g. Oil 1), whilst multiple intermediate point heating are required to minimize the loss in throughput with heavier oils. When approaching the problem here presented, one difficulty is, of course, predicting the

evolution of oils quality in the long term. When carrying out a retrofit, it is important to look for an optimal economic/energy design for the case on hand, but also to avoid introducing bottlenecks that might limit later adaptation to more viscous feedstock.

For the cases here presented, and merely based on an analysis of loss in throughput and energy input, a suitable retrofit strategy for the entire oil quality range and evolution sequence would be:

1) To start by installing an inlet heating station HS0 to increase the incoming oil temperature to up to 90ºC before entering the pipeline section.

2) To follow with Case B (a single heating station HS1 located at L=100 km, of capacity Q = 7.4 MW), allowing full throughput transportation of oils of viscosity up to Oil 2.

3) To further increase the capacity of this HS1 station (hence its exit temperature from HS1) in a later retrofit by installing additional duty of approx. Q = 2 MW, up to a maximum capacity of 9.4 MW. This will maintain throughput between 100% and 95% for oils of viscosity intermediate between Oil 2 and Oil 3, respectively.

4) As oil becomes heavier still (significantly heavier than Oil 2, closer to Oil 3) to install a second heating station (HS2) at 2/3 of the pipeline length (200 km from inlet), of progressively increasing capacity up to 9.4 MW. Now two intermediate heating stations operate (HS1 and HS2), as in Case F. This would lead to significant savings in throughput for Oils 3 and 4 by just adding a single station.

5) Redistribution of the same heat duty over 3 heating stations with minor duty additions (as in Case G) would enable further throughput improvements with the heavier oils.

Clearly, there are many possibilities for initial retrofit and gradual adaptation, and the best strategy can only be found with a detailed techno-economic analysis based on forecasted oil grade scenarios.

Some general observation can be made. Current industrially tested point heating technologies are mainly restricted to fired heaters or heat exchangers. These systems require building ancillary processing stations and infrastructure (e.g. piping, steam generators, pumps, power stations), greatly impacting the original pipeline infrastructure and leading to additional pressure drops [7]. For the amount of infrastructure change required, this is as significant as installing an additional pumping station. Continuous heating technologies, such as the skin-effect electrical heating system used in the Mangala pipeline also require significant infrastructures (e.g. auxiliary gas pipeline, power generation stations, special pipeline design)[8]. Once installed, these options are difficult to retrofit (e.g. upgrade or relocate). Therefore future demands must be considered at the design stage and infrastructure built-in at the onset, if the pipeline is to deal with a wide spectrum of possible future scenarios. Thus, it must be greatly overdesigned, at significant upfront capital cost.

Single and multi-point heating strategies that can be easily upgraded by the incremental addition of heating capacity would offer a potential alternative to cold drag reduction techniques or the installation of new pumping/heating stations. To achieve these benefits, the heating technology needs to feature low impact on existing infrastructure and be easy to set-up, dismantle and retrofit. A modular design and installation, with flexible capacity addition and low capital cost, would meet these requirements. The ability to use a variety of fuels at high efficiency, to provide good performance over a wide heating range (turn-down ratios) and be easy to control are additional desirable features.

Direct surface heating of the pipeline using flameless catalytic heating [30–33] is a new emerging technology for industrial heating that seems to fit the above requirements. Of particular interest is its ability to be ‘wrapped around’ existing pipelines (implying low installation costs and ease of maintenance), its modular design (for easy incremental addition/removal of duty), and high operating efficiency. The development of such a technology would offer an interesting thermal strategy alternative to current methods for retrofit of pipelines to handle heavier oils.

5. CONCLUSIONS

A single and multipoint intermediate heating strategy can be beneficially used to retrofit existing pipelines, initially designed to transport light oil, so as to enable the transport of much heavier crude oils. Through intermediate heating, viscosity is reduced and significant reduction in throughput losses can be achieved. The thermo-hydraulic analysis presented shows that the same amount of heating energy input may have quite different effects depending on the location of the heating stations. A retrofit strategy is proposed aimed at retaining maximum throughput for changes to progressively more viscous oils, subject to given overall pressure drop and maximum oil temperature constraints. Options considered include varying the number and location of intermediate heating stations and their heat duty (and temperature increase). Choosing the best set of options is a complex combinatorial problem that requires a detailed techno-economic analysis for projected oil change scenarios. The strategy proposed involves the incremental addition and relocation of heating duty as the oils become progressively more viscous. This approach will be made particularly advantageous over other options (emulsion, dilution, or installation of new pumping stations) by the development of easy to install, modular, high efficiency, low-cost heating technologies, some of which were identified.

As a next step, the thermo-hydraulic pipeline model presented in this paper could be validated against experimental data, either for industrial scale pipelines or pilot plant scale facilities, for example, by comparing flow temperature, flow pressure, and insulation surface temperature measurements to the simulation results. The flexibility of the framework presented allows easy adaptation to a wide variety of environmental conditions, fluids and pipeline configurations. The validation of the pipeline model and consideration of detailed economics for specific heating technologies are left as subjects of future work.

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NOMENCLATURE

API	=	API gravity
C_p	=	Specific heat capacity, J kg^{-1} K^{-1}
e	=	Specific enthalpy, J kg^{-1}
ESPO	=	Eastern Siberia-Pacific Ocean
f	=	Friction factor, -
h	=	Convective heat transfer coefficient, W m^{-2} K^{-1}
HS	=	Heating station
L	=	Pipeline length, m
$MeABP$	=	Mean average boiling point, °C
$\dot{m}$	=	Mass flowrate, kg s^{-1}

P = Pressure, Pa

Q = Heat duty, W

$q"$ = Heat flux, W m^{-2}

R = Radius, m

r = Radial coordinate, m

T = Temperature, K

t = Time, s

u = Linear velocity, m s^{-1}

z = Axial coordinate, m

Subscripts

env = Environment

fr = Friction

gr = Ground surrounding the pipeline

i = Inner

in = Inlet

ins = Insulation

j = Pipeline module number

$losses$ = Losses through pipe inner surface

max = Maximum

o = Outer

out = Outlet

vol = Volume

w = Pipeline wall

Greek letters

ΔP = Pressure drop, MPa

ΔT = Temperature increase between pipeline modules, ºC

δ = Distance ground surface to pipe centre, m

ρ = Density, kg m^{-3}

λ = thermal conductivity, W m^{-1} K^{-1}

ν = kinematic viscosity, mm^2 s^{-1}

$\nu_{38°C}$ = kinematic viscosity at 38^0C, mm^2 s^{-1}

τ_w = Wall shear stress, N m^{-2}

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Table 1. Pipeline geometry and operating conditions.

Parameter	**Value**
$R_{w,i}$ [m]	0.3906
δ [m]	1.5
λ_{gr} [W/mK]	1.2
Ins. Thickness [m]	0.08
λ_{ins} [W/mK] (foam)	0.03
Max.flow [Mtpa]	15
u_{in} [m/s]	1.14
MAOP [MPa]	8
ΔP_{max} [MPa]	4.8
T_{env} [ºC]	-40

Table 2. Characteristic parameters of the oils.

Oil	**API**	**MeABP (ºC)**	**$\nu_{38ºC}$ ($mm^2\ s^{-1}$)**
ESPO	34	280	5.1
1	24	350	120
2	22	350	150
3	20	400	300
4	18	450	450

Table 3. Maximum length transported with and without inlet heating and loss in throughput required for heavy oils to meet the maximum pressure drop constraint with inlet heating-.

Oil	**ESPO**	**Oil 1**		**Oil 2**		**Oil 3**		**Oil 4**	
Case	**1**	**1**	**2**	**1**	**2**	**1**	**2**	**1**	**2**
Inlet Heating	No	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes
T_{in} [^{o}C]	-6	-6	90	90	90	90	90	90	90
Throughput	Max	Max	Max	Max	Reduced	Max	Reduced	Max	Reduced
u_{in} [m/s]	1.14	1.14	1.14	1.14	1.11	1.14	1.04	1.14	0.96
$L_{(\Delta Pmax)}$ [km]	300	38	300	288	300	264	300	239	300
L_{ESPO}–$L_{(\Delta Pmax)}$ [km]		-262	0	-12	0	-36	0	-61	0
Throughput Loss [%]		-	0	-	2.7	-	8.8	-	15.8
Throughput Loss [Mtpa]		-	0	-	0.405	-	1.320	-	2.370

Table 4. Minimum throughput loss for various retrofit options

Oil	**Oil 1**		**Oil 2**		**Oil 3**		**Oil 4**	
Units / **Retrofit option**	**%**	**Mtpa**	**%**	**Mtpa**	**%**	**Mtpa**	**%**	**Mtpa**
Inlet heating only	0	0	2.7	0.405	8.8	1.320	15.8	2.370
1 int. heating(A-E)	-	-	0	0	4.5	0.675	10.6	1.590
2 Int. heating (F)	-	-	-	-	3.3	0.495	9.2	1.380
3 Int. heating (G)	-	-	-	-	2.7	0.405	8.5	1.275

Table 5. Total temperature rise and heat input at intermediate stations for various retrofit options

Oil	**Oil 1**		**Oil 2**		**Oil 3**		**Oil 4**	
Case	**ΔT (^{o}C)**	**Q (MW)**	**ΔT (^{o}C)**	**Q (MW)**	**ΔT (^{o}C)**	**Q (MW)**	**ΔT (^{o}C)**	**Q (MW)**
Inlet heating only	0	0	0	0	0	0	0	0
1 int. heating (A; B)	-	-	11; 8	10.2; 7.4	14.8; 10.1	13.9; 9.4	15.2; 10.4	13.6; 9.2
2 Int. heating (F)	-	-	-	-	19.8	18.8	20.3	18.4
3 Int. heating (G)	-	-	-	-	22.3	21.3	22.8	20.9

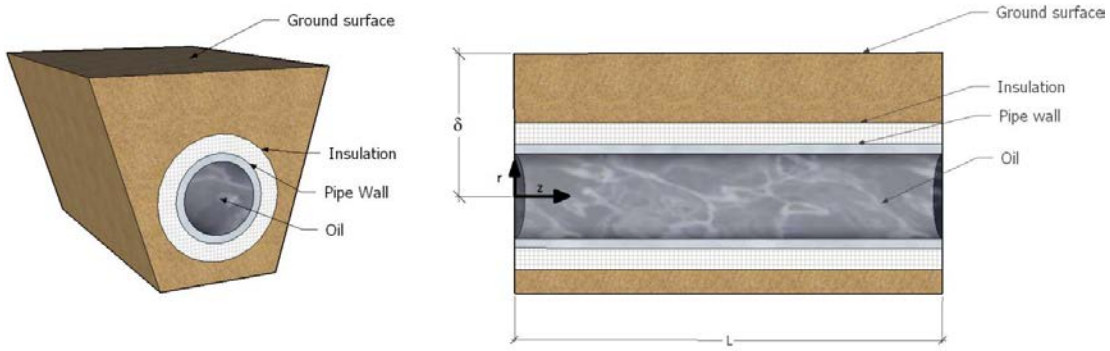


Figure 1. Schematic representation of buried, unheated, insulated pipeline and the domains considered in the model.

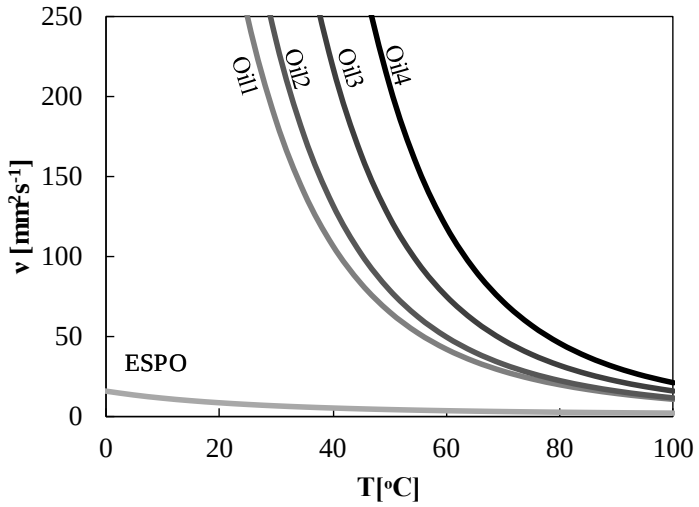


Figure 2. Viscosity vs. Temperature for the oils considered

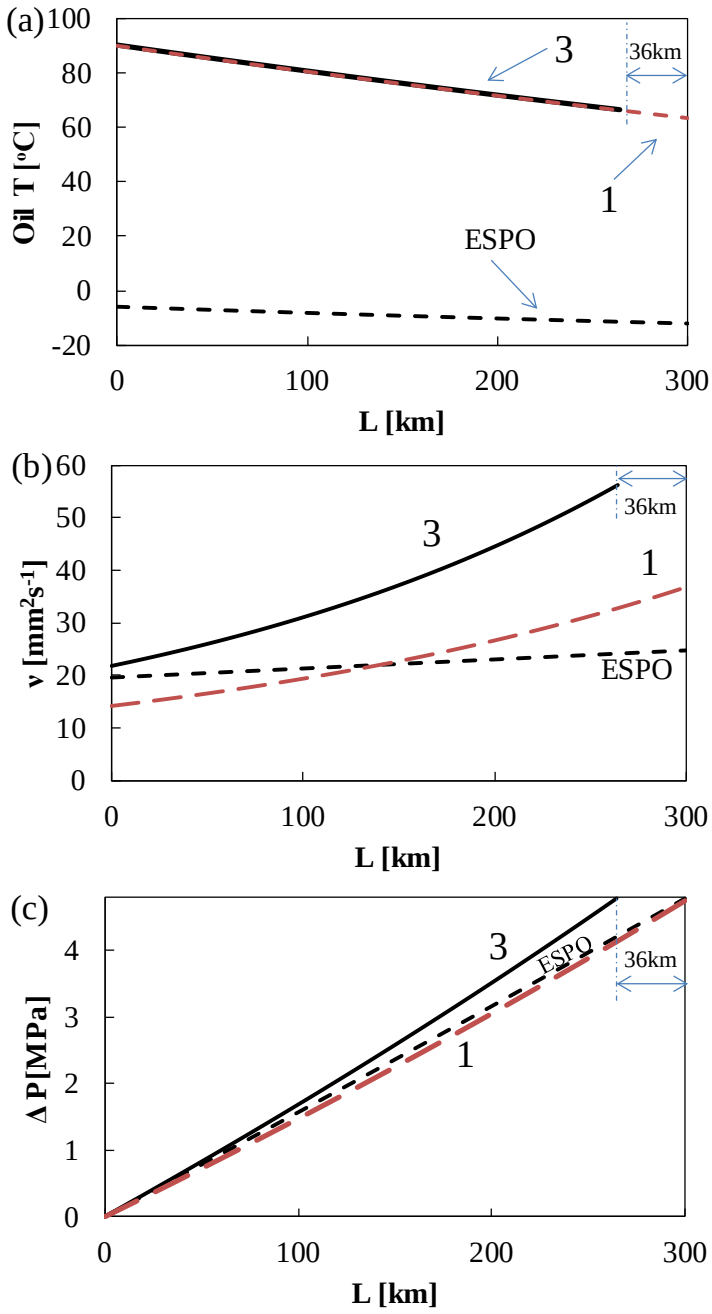


Figure 3. Temperature (a), viscosity (b), and pressure drop (c) profiles for ESPO, Oil 1 and Oil 3 (maximum throughput)

Case	L/4	L/3	L/2	2L/3	3L/4	No. Stations
A			ΔT_A			*1*
B		ΔT_B				*1*
C	ΔT_C					*1*
D				ΔT_D		*1*
E					ΔT_E	*1*
F		$\Delta T_F/2$		$\Delta T_F/2$		*2*
G	$\Delta T_G/3$		$\Delta T_G/3$		$\Delta T_G/3$	*3*

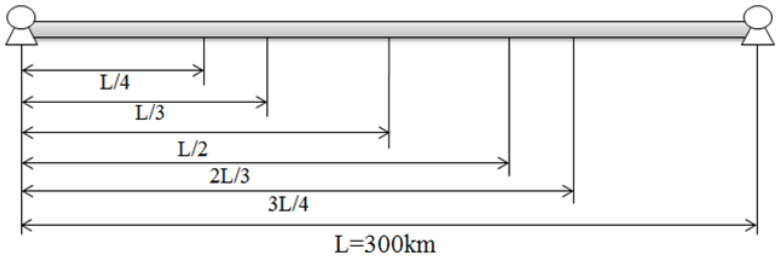


Figure 4. Location of intermediate heating stations and temperature increase at each station for cases A-G

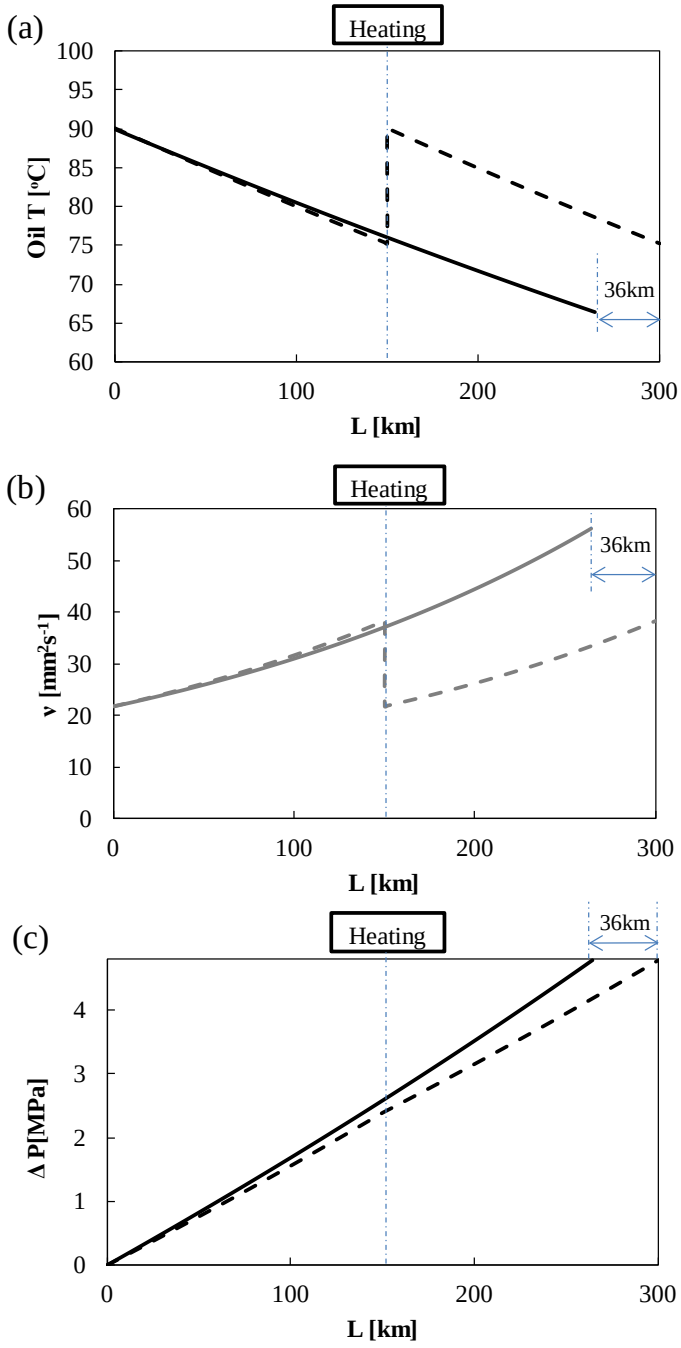


Figure 5. Temperature (a), viscosity (b) and pressure drop (c) profiles for Oil 3: max throughput (continuous line); and single heating point, case A (dashed line).

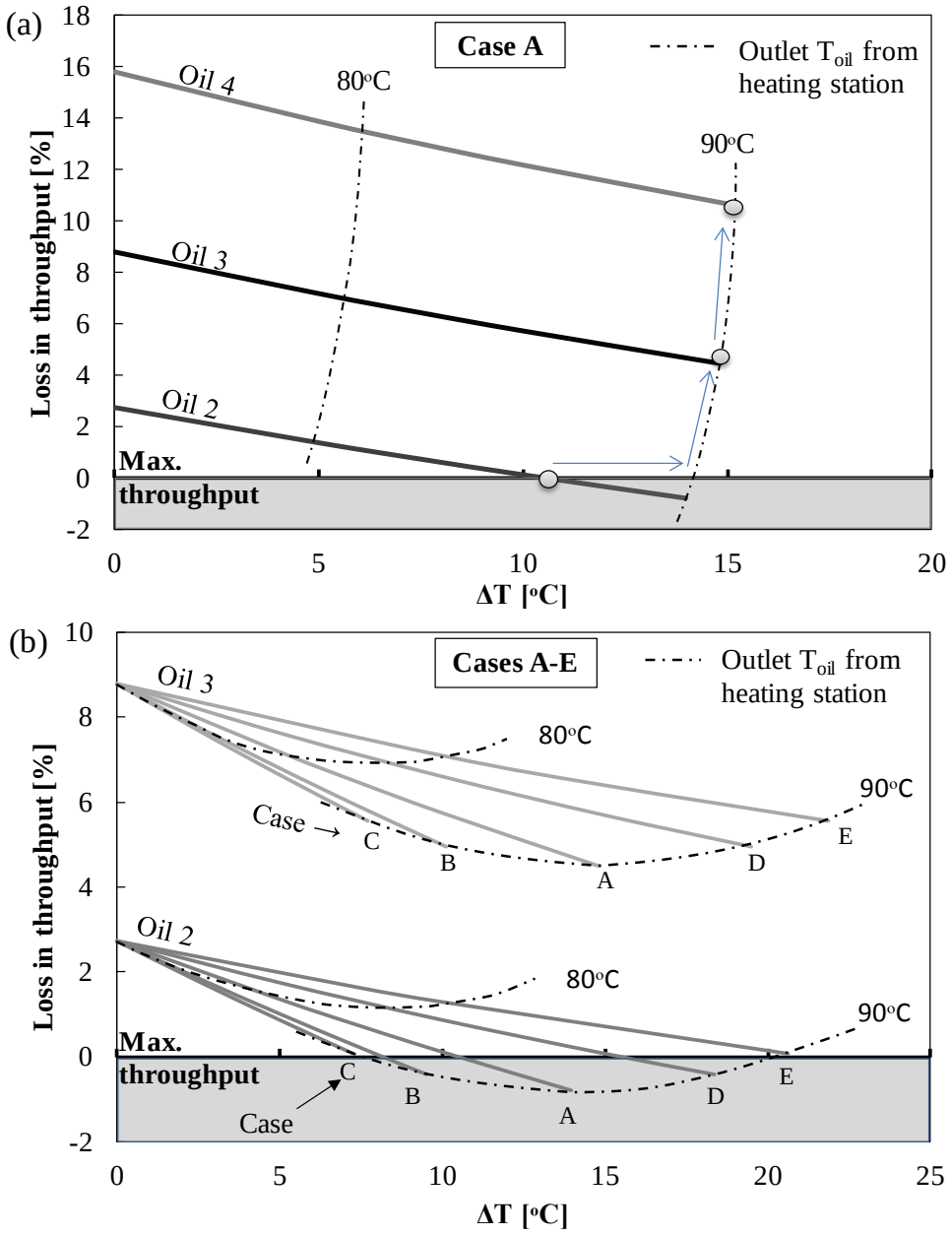


Figure 6. Loss in throughput vs. temperature increase for single heating at the midpoint (a) and at different locations (b) for heavy oils. The arrows in (a) indicate a potential adaptation pathway for Case A as the oil becomes progressively heavier.

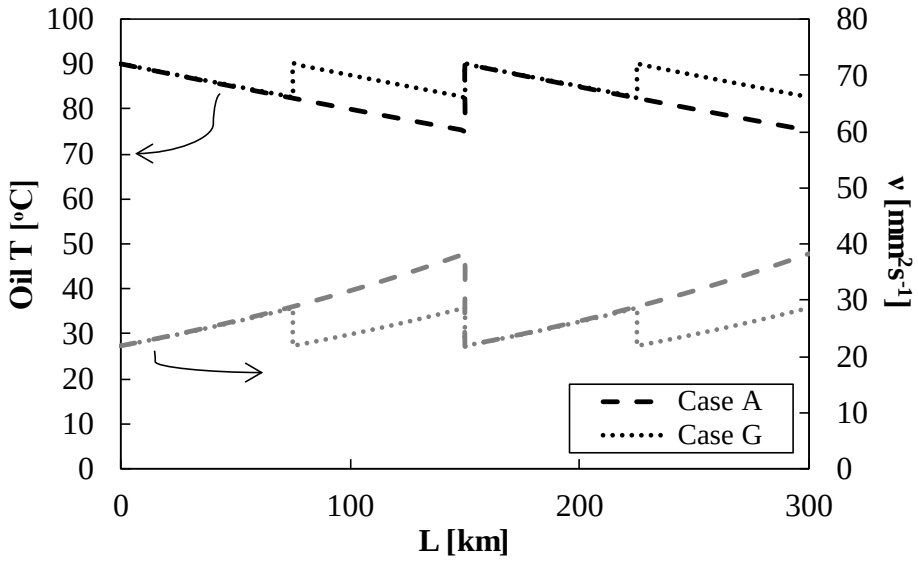


Figure 7. Temperature and viscosity profile for Oil 3, cases A and G, and outlet temperature of 90ºC

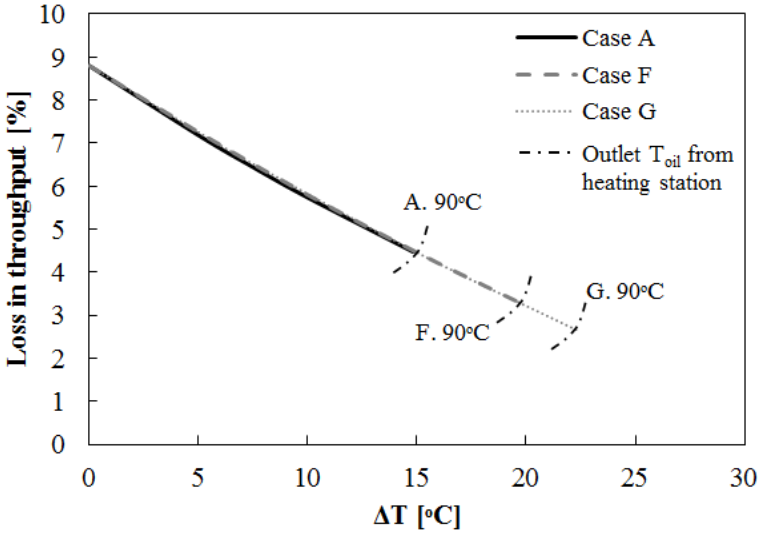


Figure 8. Throughput loss vs. total ΔT for Oil 3, cases A, F and G