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FLOW ASSURANCE OPERATIONAL PROBLEMS IN NATURAL GAS PIPELINE TRANSPORTATION NETWORKS IN NIGERIA AND ITS MODELING USING OLGA AND PVTSIM SIMULATORS

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Abstract

The challenges associated with natural gas Pipeline flow assurance is an increasingly important issue as the world supply for natural gas expands, and is expected to rise more strongly to match the global demand for a cleaner energy. Flow assurance challenges in pipelines include hydrate formation, paraffin wax deposition, asphaltene deposition, sand deposits, black powder, and on the wall of pipelines, all of which obstruct the flow of well fluids and associated produced hydrocarbons. This study addressed these flow assurance concerns from a technical view by quantifying the threats and establishing appropriate mitigation schemes, leading to designed solutions and operational procedures. Modeling and simulation approach was adopted to achieve the overall aim. The simulation software tools PVTsim and OLGA were used for both steady state and dynamic states. The phase envelope investigation indicates that the cricondentherm within the constraint of the delivery temperature. The slugging analysis, indicates that hydrodynamic slugging will not be predominant for the pipeline operations at the design flow rate of 30MMscfd along Alakiri – Obigbo, and at 70MMscfd along the Obigbo Tie-in - Intermediate scrap station; as the flow regimes are mainly stratified for both pipeline systems. From the hydrate analysis investigated, after a shutdown period (no-touch time); hydrate threat is envisaged during the shutdown period of the Intermediate scraper trap – ALSCON along pipeline system, since the temperature drops to the hydrate formation temperature.

Keywords: *Flow Assurance; Pipeline; Natural Gas; Modeling.*

1. Introduction

Global energy demand has rapidly increased as a result of increase in population and industrialization, with oil and natural gas constituting over 65% of the primary sources. Measured in financial indicators, 90% of chemical products in industrially developed countries are from organic sources whose 98% production are based on oil and natural gas as basic organic chemical feeds [1]. Since petroleum as an energy source is non-renewable, the crude reserves are fast declining due to long period of utilization while the global focus is now shifting towards natural gas as the major source of energy due to its abundance availability, economic viability and environmental friendliness. The increasing use of natural gas as a primary fuel source has led to its greater production and exportation in gaseous and liquid (Liquefied Natural Gas (LNG) forms from many countries that hold sufficient reserves. This has equally increased the global transboundary pipeline networks with minimal considerations to the impacts of its failure it could have on the environment [2]. Natural gas is a combustible gaseous mixture of light hydrocarbon compounds and other components. Its main components are methane (CH_4) and other non-reactive hydrocarbons in gaseous state at ambient temperature and atmospheric pressure. The gas with low energy density is either found in association with crude oil (either dissolved at high temperature and pressure or as gas cap in the same reservoir) or as a non-associated gas. This origin of formation, coupled with type, location of deposit, geological structure of the region and other factors determine its composition. The gas is colorless and odorless in its pure state and when burnt, it gives off a great deal of energy with low level of pollutants compared with other fossil fuels [2].

The oil industry is currently working under completely different circumstances than thirty years ago. The oil companies have a desire to develop marginal fields far from land, and at other nodes at greater water depths than before. Oil recovery can now be accomplished down to 9,843ft of water depth. At such extreme depths, the seawater is cold, which increases the risk of hydrate formation in pipelines [3]. Flow assurance challenges in pipelines include hydrate formation, paraffin wax deposition, asphaltene deposition, sand deposits, black powder, and on the wall of pipelines, all of which obstruct the flow of well fluids and associated produced hydrocarbons. Oil and gas pipeline flow assurance technology puts forward flow assurance measures through predicting the flow variation of oil and gas in the pipeline and evaluating the flow safety.

Flow assurance refers to ensuring successful and economical flow of hydrocarbon stream from reservoir to the point of sale and is closely linked to multiphase flow technology. Flow assurance developed because traditional approaches are inappropriate for deepwater production due to extreme distances, depths, temperatures or economic constraints. While flowing through a long pipeline, it is important to take an account of viscosity, acidity and salt content for field operations. All these factors can affect pipeline capacity. The process of ensuring a constant flow of oil despite different issues which can cause flow obstacles is known as flow assurance. Although flow assurance consists of a spectrum of issues, four main issues are: corrosion, salts, asphaltenes and waxes [4].

The challenges associated with natural gas pipeline flow assurance is an increasingly important issue as the world supply for natural gas expands, and is expected to rise more strongly to match the global demand for a cleaner energy. This study was tailored towards addressing these flow assurance concerns from a technical view by quantifying the threats and establishing appropriate mitigation schemes that will lead to designing solutions and operational procedures.

2. Flow assurance brief background

During flow through pipeline, wax may be deposited on pipe walls. A thermal gradient between the outside ambient conditions and the internal oil flow must exist for flow deposition. The internal wall temperature due to the gradient must be below the initial wax appearance temperature. In addition, internal shear forces in the flow must be low enough to allow crystal growth. Wax deposits, can grow and restrict flow. While it is rare for deposition to completely shut down a pipeline, the loss in production capacity is a major concern during waxy crude oil transportation through pipelines. Flow assurance is an important area for multiphase flow of oil, gas and water to minimize financial loss for the petroleum industry [5].

The term flow assurance was first used by Petrobras in the early 1990s in Portuguese as Garantia do Escoamento (pt::Garantia do Escoamento), meaning literally "Guarantee of Flow", or Flow Assurance. Flow assurance is extremely diverse, encompassing many discrete and specialized subjects and embrace all kinds of engineering disciplines. Besides network modeling and transient multiphase simulation, flow assurance involves handling many solid deposits, such as, gas hydrates, asphaltene, wax, scale, and naphthenates. Flow assurance is a most critical task during deep water energy production because of the high pressures and low temperature involved. The financial loss from production interruption or asset damage due to flow assurance mishap can be astronomical.

What compounds the flow assurance task even further is that these solid deposits can interact with each other and can cause blockage formation in pipelines and result in flow assurance failure. Flow assurance is applied during all stages of system selection, detailed design, surveillance, troubleshooting operation problems, increased recovery in late life etc., to the petroleum flow path (well tubing, subsea equipment, flowlines, initial processing and export lines).

The gas is located thousands of meters below the earth surface with the fluid's pressure in the pores of the rocks ranging between 10MPa/km while in hydrostatic regime (only supporting the weight of the overlying fluid column) to 25MPa/km in geostatic regime (supporting all or part of the weight of the rock column) [6]. Various transportation options of natural gas from off-take include long pipelines transport, methanol, Liquefied Natural Gas (LNG) and compressed natural gas (CNG) of pressure between 3000 and 3600 psi [7]. From these options, only long pipelines and LNG are in common use. The unit cost of pipeline option is clearly superior to that of LNG due to the required high cost of refrigeration and liquefaction of boiled-off liquids and the high risk of over-pressurization for LNG. Pipelines are mainly divided into gas and oil pipelines depending on the nature of the cargo conveyed. Main components of a pipeline network are operational areas and the pipeline segments. Operational areas may be distribution centers, ports or refineries and are connected by pipeline segments. Gas and liquid hydrocarbon pipelines are essentially similar with the greatest operational difference resulting from the varying needs of transporting gas versus liquid. Oil pipelines require pumps to propel the liquid contents while gas lines rely on compressors to force the resource through the pipes.

From field processing facilities, the dried, cleaned natural gas enters the gas transmission pipeline system, analogous to the oil trunk line system [8]. Gas pipelines are usually buried underground about 3-7ft in lands or rights-of-way acquired by, or granted to the pipeline company. Whenever burying the pipe becomes less convenient, the strategy is to place the pipeline 5-6ft above the ground (under strict specifications to withstand environmental conditions) in order to allow for wildlife or any other factor that might damage the pipe. Surely, without pipeline we would not be able to satisfy the huge oil and gas demand of our planet. Pipelines have provided economic, reliable means to transport oil and natural gas from upstream production, often very remote regions, to downstream refineries, power stations, crossing nations, oceans, and continents.

3. Methodology

The system consists of network of pipelines connected in segments. The starting point is Alakiri field of Rivers State and the final receiving point is the ALSCON station at Ikot Abasi (Etetuk) of Akwa Ibom state. The primary fluid flowing is an associated gas from SPDC sources with the aim of supplying gas to the Aluminium Smelting Company of Nigeria (ALSCON).

To study the flow assurance challenges associated with the operations of the Nigeria Gas Company limited (NGC) gas supply pipeline from Alakiri to ALSCON station at Ikot Abasi of Akwa-Ibom state of Nigeria, hydraulic data was collected from NGC.

The pipeline network is about 114km which comprises of three major pipeline segments.

SEGMENT 1: The line diameter is 14" and the length of the segment is about 32km. The starting point is Alakiri launching scraper trap station. The end segment is at Obigbo North tie-in receiving trap station. The first 17km of the pipeline runs parallel to the existing Nigerian Gas Company Alakiri-Onne gas pipeline, traversing mainly swamp area and cross the Bonny River. The last 15.2km of the pipeline traverses mainly build-up area and crosses the following features; railway, express road, tarred roads, pipelines.

SEGMENT 2: The line diameter is 16" and the length is about 44.4km. Starting point is Obigbo North tie-in scraper station and the ends at Intermediate scraper trap station.

SEGMENT 3: The starting point is Intermediate scraper trap station and the end of the segment is at Aluminium Smelting Company of Nigeria (ALSCON) at Ikot Etetuk. The pipeline diameter is 24" and the length is about 37.7km. Currently, the flow assurance problems solved in the above pipeline network system were the hydraulic parameters verification (Pressure, temperature and flow rate).

This study developed flow assurance studies using OLGA software tool, this tool was used to define pipeline operating procedures and control schemes with the aim of ensuring smooth operation during the transportation of the produced gas fluid. OLGA version 7.0 transient simulator was used to build and analyze models for the Alakiri-Obigbo-Ikot Abasi (ALSCON) pipeline network system. The fluid composition was made suitable for use by OLGA via the use of PVTsim to create table files, which transfers fluid thermodynamic properties into OLGA software format.

The model assume that inlet to the system is a closed node and a mass source that provides the specified flow rate is placed at the inlet node. Since the ALSCON conditions are known and specified at the outlet node of the model, the simulator is able to compute the required parameters along the pipeline length down to the inlet node, such that the entire process from the inlet to the receiving facilities are fully defined.

PVTsim was used to characterised the fluid and predict the hydrocarbon phase envelope characteristics at the Alakiri gas source composition and Obigbo source gas composition.

4. Development of the simulation models with available data

Operating conditions: The information gathered from the acquired data shows that the gas will be delivered to ALSCON pipeline at the delivery points at a maximum pressure of 60 bar. Gas temperature at delivery points: Alakiri gas source: 37.5°C; Obigbo gas source: 46.7°C

Gas operating conditions at the ALSCON Terminal station downstream of the metering system at the NGC battery limit are:
Temperature: Maximum: +35°C; Minimum: +20°C.
Pressure: Maximum: 40bar; Normal: 30bar; Minimum: 25bar.
Gas flow rate: Alakiri-Obigbo: 30MMSCFD; Obigbo-Ikot Etetuk: 100MMSCFD.

For the hydraulic calculation the following pipe characteristics have been assumed:
14" OD wall thickness: 6.4mm; 16"OD wall thickness: 6.4mm; 24" OD wall thickness: 11.9mm.

4.1. Modeling of the pipeline network using OLGA simulator

Based on the available data, the pipeline network system was built using OLGA software tool. The pipeline wall is defined by the steel thickness and the insulation thickness is an unknown parameter, which is calculated based on the minimum required arrival temperature at the ALSCON terminal. The flow path is simulated using two major nodes, which are the upstream node which is defined as a closed node (no flow across the node) and the downstream node is modelled as a pressure node (flow across the node) in which the arrival pressure is 60 bar. The models in OLGA are as shown in Figure 1.

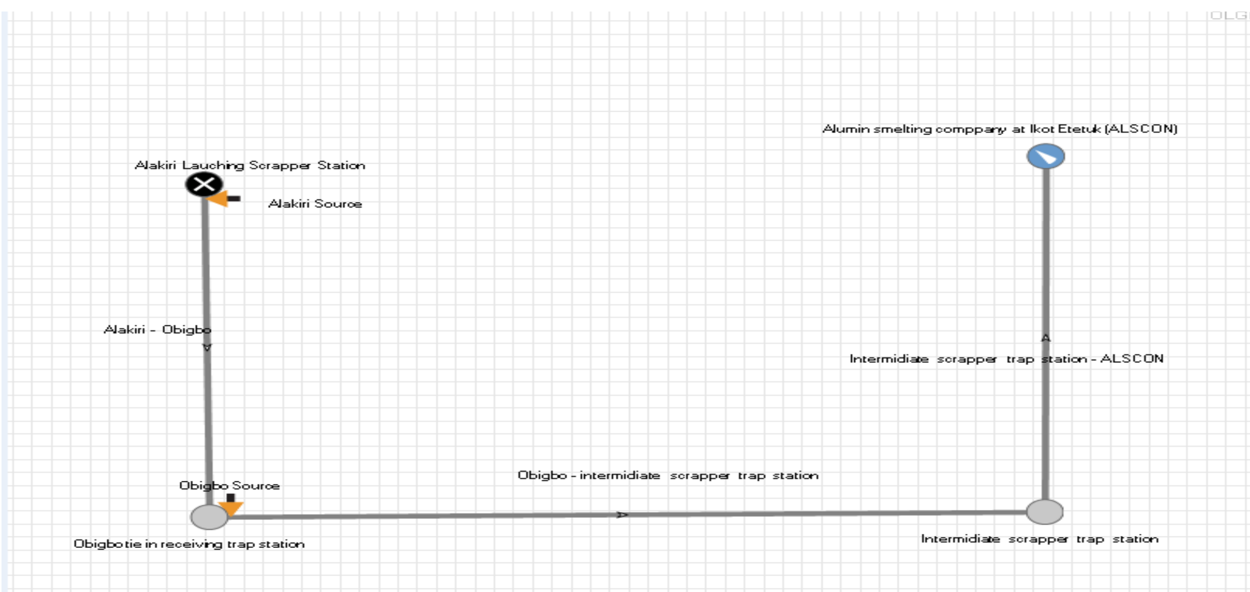

Figure 1. Schematic diagram of OLGA models with nodes and source inlet

From the figures 2 and 3, we have two sources, four nodes, and three flow paths; these pipeline network system points are defined as stated below:
SOURCES: Source 1: Alakiri source; Source 2: Obigbo source
NODES: Node 1: Alakiri source; Node 2: ALSCON at Etetuk; Node 3: Intermediate scraper trap station; Node 4: Obigbo tie –in
FLOW PATHS: Flow path 1: Alakiri-Obigbo; Flow path 2: Obigbo-Intermediate scrapper station; Flow path 3: Intermediate scrapper station- ALSCON at Etetuk.

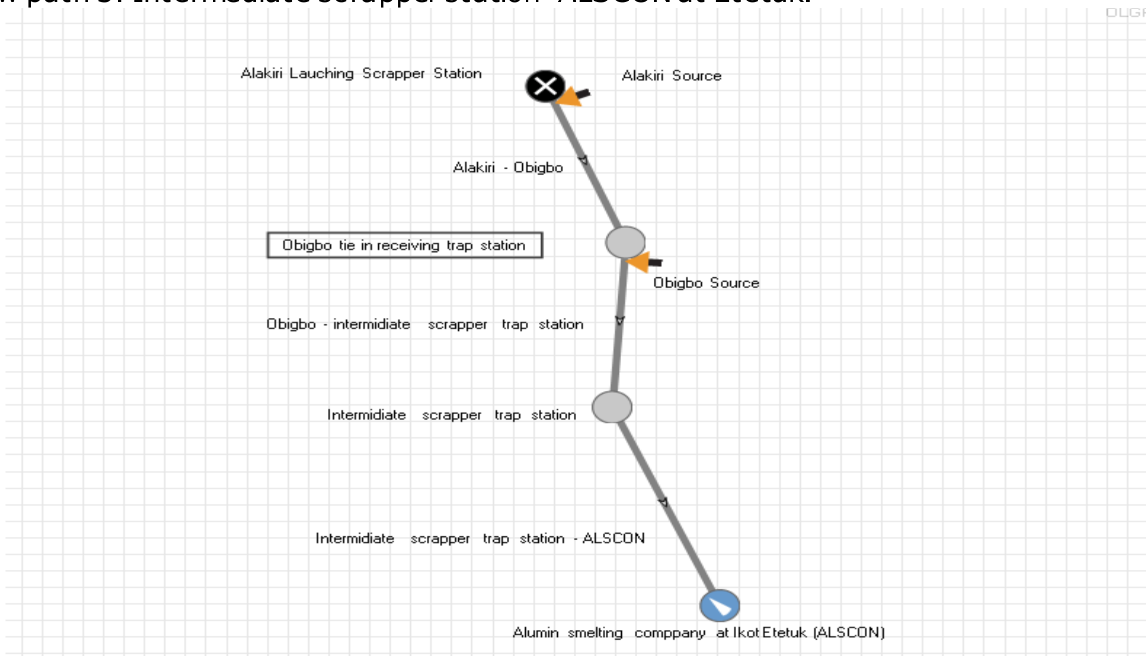

Figure 2. Schematic diagram of OLGA models with nodes and source inlet

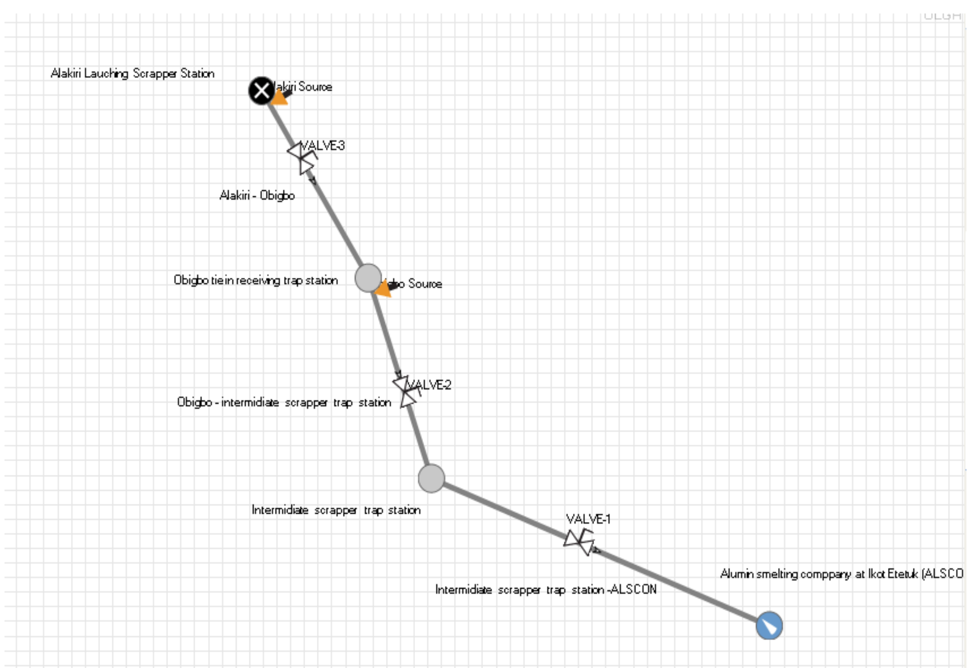

Figure 3. Schematic diagram of OLGA models with valves along the flow path with nodes and sources inlet

Geometry of the Pipeline

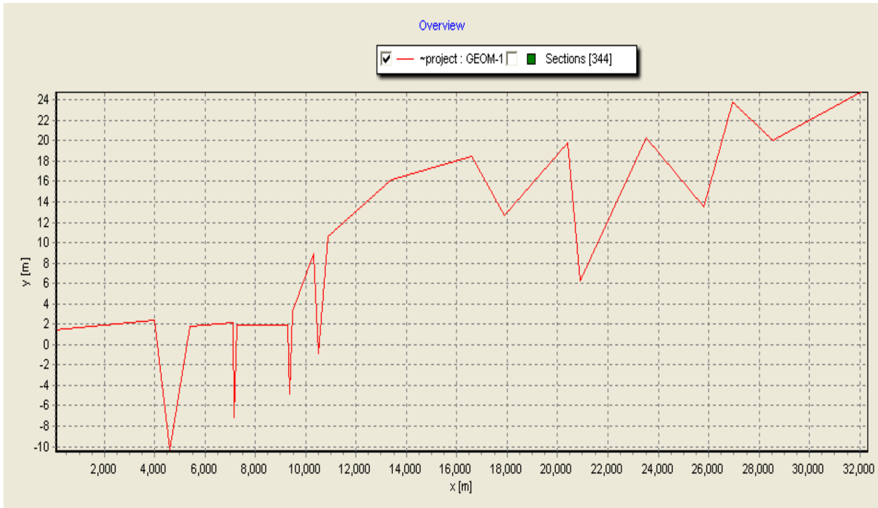

Figure 4. Alakiri - Obigbo Tie-in Profile Plots

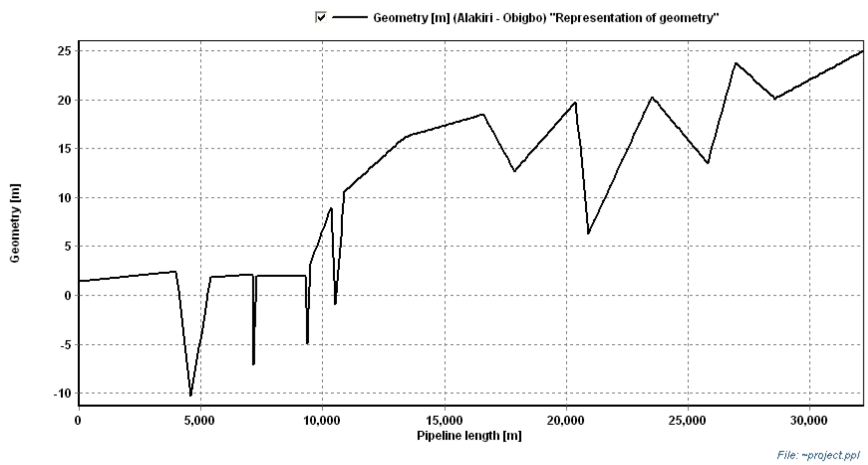

Figure 5. The Alakiri – Obigbo Trap Station Profile Plots

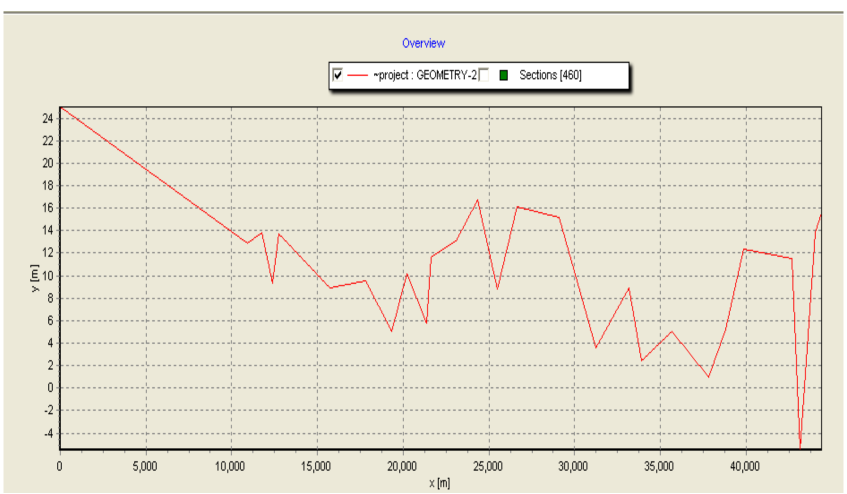

Figure 6. The Alakiri – Obigbo Profile Plots

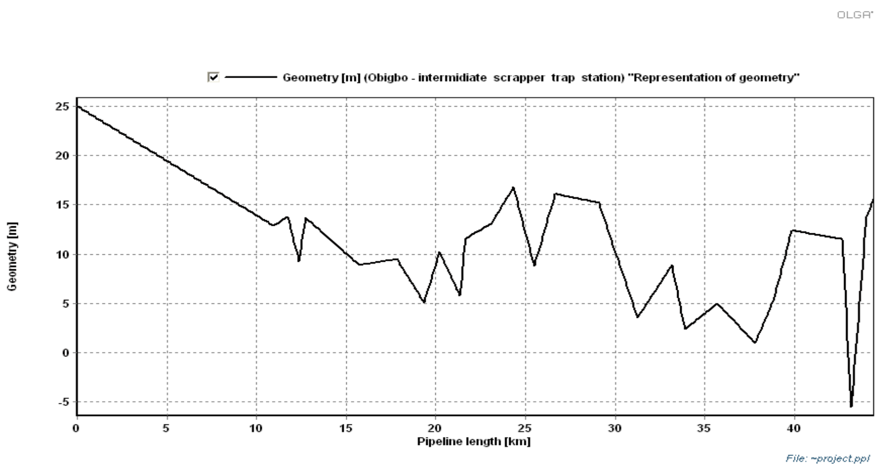

Figure 7. The Obigbo – Intermediate Scrapper Trap Station Profile Plots

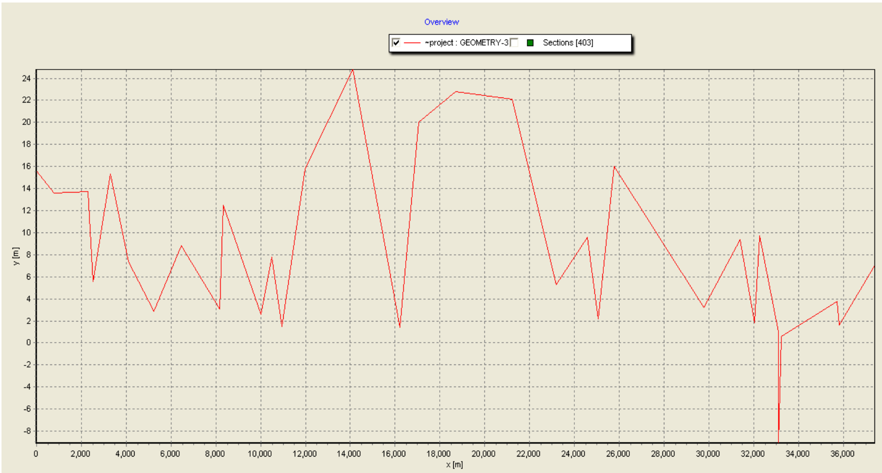

Figure 8. The Obigbo – Intermediate Scrapper Trap Station Profile Plots

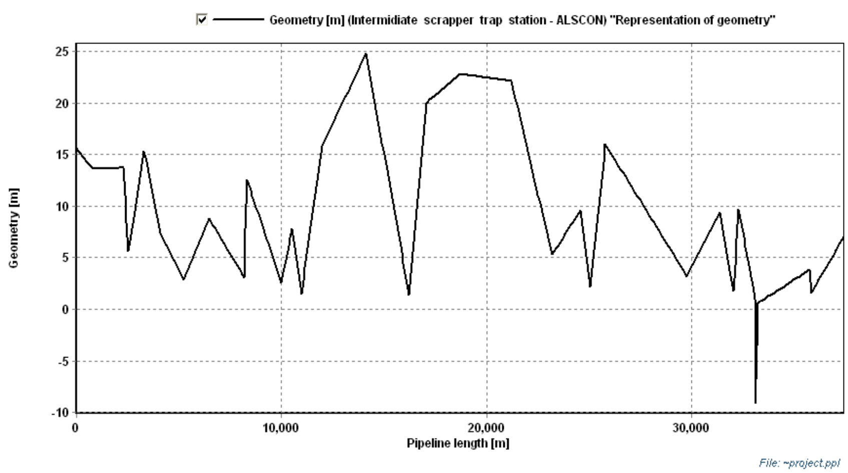

Figure 9. The Intermediate Scrapper Trap Station- ALSCON at Etetuk profile plots

5. Results and discussion

5.1. Phase envelope

From the phase envelope in Figures 10 and 11, the cricondentherm which is the maximum temperature above which liquid cannot be formed regardless of the pressure for Alakiri is -7.27^{0}C and the corresponding cricondentherm pressure is 51.05bar. The cricondenbar which is the maximum pressure above which no gas can be formed regardless of the temperature is found to be 86.98bar and the corresponding cricondenbar temperature is -28.05°C; while the critical temperature is -47.33°C and the critical pressure is 76.87bar.

Likewise, the cricondentherm for Obigbo is $18.18.4^{0}$C and the corresponding cricondentherm pressure is 43.97bar. The cricondenbar is found to be 100.44bar and the corresponding cricondenbar temperature is -17.17^{0}C; while the critical temperature is -52.56^{0}C and the critical pressure is 75.15bar. From the available data, the gas will be delivered to the ALSCON pipeline at the delivery points at a maximum of 60bar. The gas temperature at the delivery points are:

- Alakiri gas source is 37.5^{0}C
- Obigbo gas source is 46.7^{0}C

This suggests that for optimum transmission of natural gas with the given composition and condition and to ensure that no liquid entrainment is present; the temperature of the gas should be above the cricondentherm temperatures and the pressure should be above the cricondenbar pressure values found for Alakiri and Obigbo source respectively.

However, the gas transmitted is at 37.5^{0}C and 46.7^{0}C for both Alakiri and Obigbo respectively, which implies that both sources are within the constraint of the temperature, which will not encourage the presence of a liquid phase in the gas. Conversely, liquid formation in the pipeline is still possible since the cricondenbar pressures are above the gas delivery pressure, this is expected because the gas is hydrocarbon wet which suggests the presence liquid hydrocarbon, hence two phase. So if there is a possibility of these undesired slugs of liquid, then a suction knock-out pots should be install as close as possible to the compressor, with drains, level detection and trip functions, in order to remove these liquid entrainment before it is allowed into a compressor.

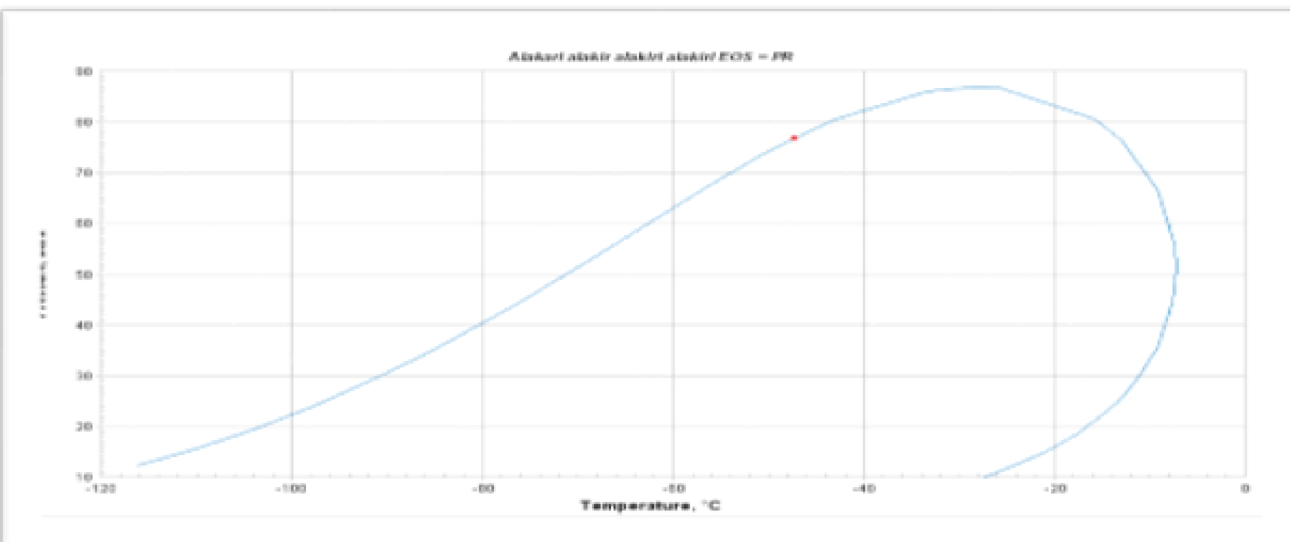

Figure 10. Alakiri Source Phase Diagram

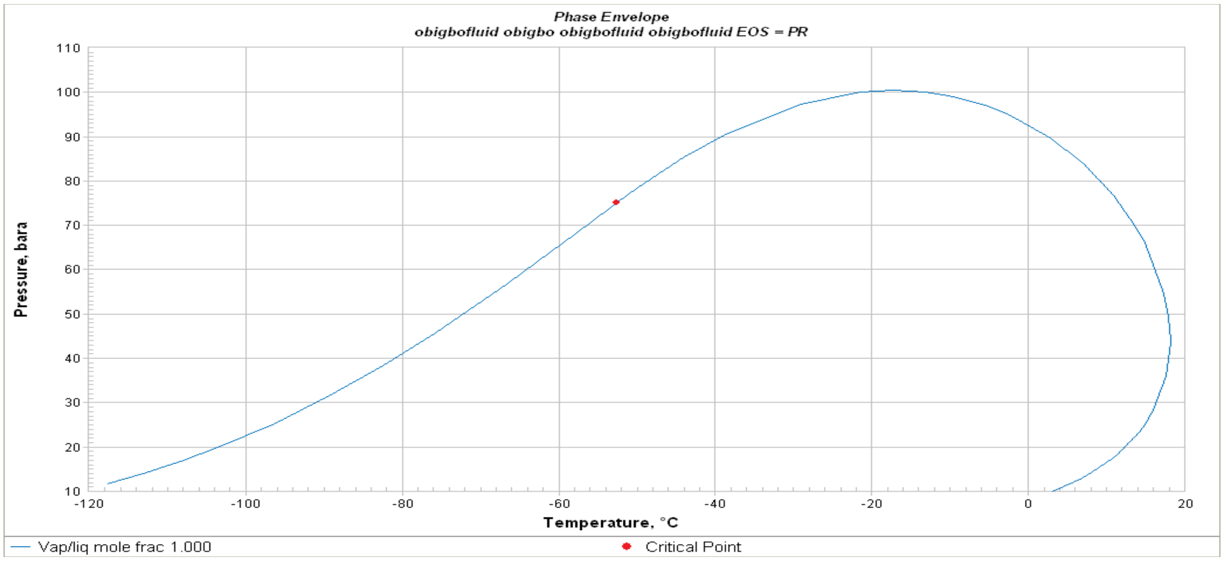

Figure 11. Obigbo source phase diagram

5.2. Steady state simulation model validation with reference to existing data

The steady state analysis was based on gas flow rate of 100MMscfd at the ALSCON terminal station. The system is designed for a maximum pressure and minimum inlet pressure of 40barg, and 25barg respectively, also, with a minimum temperature of 20^{O}C at the ALSCON terminal. Other operating conditions are the Alakiri source temperature of 37.5^{0}C and Obigbo source temperature of 46.7^{O}C. The model built was compared with the existing data. Although there is no conversion from Barg (Gauge pressure) to (Absolute pressure) as atmospheric pressure changes from day to day. However, an approximate conversion can be made by simply adding 1000mBar to Bar*g* to obtain a pressure value in Bar, with error difference of 50mBar.

After performing series of steady state simulations the figures 12 - 17 were obtained and presented below:

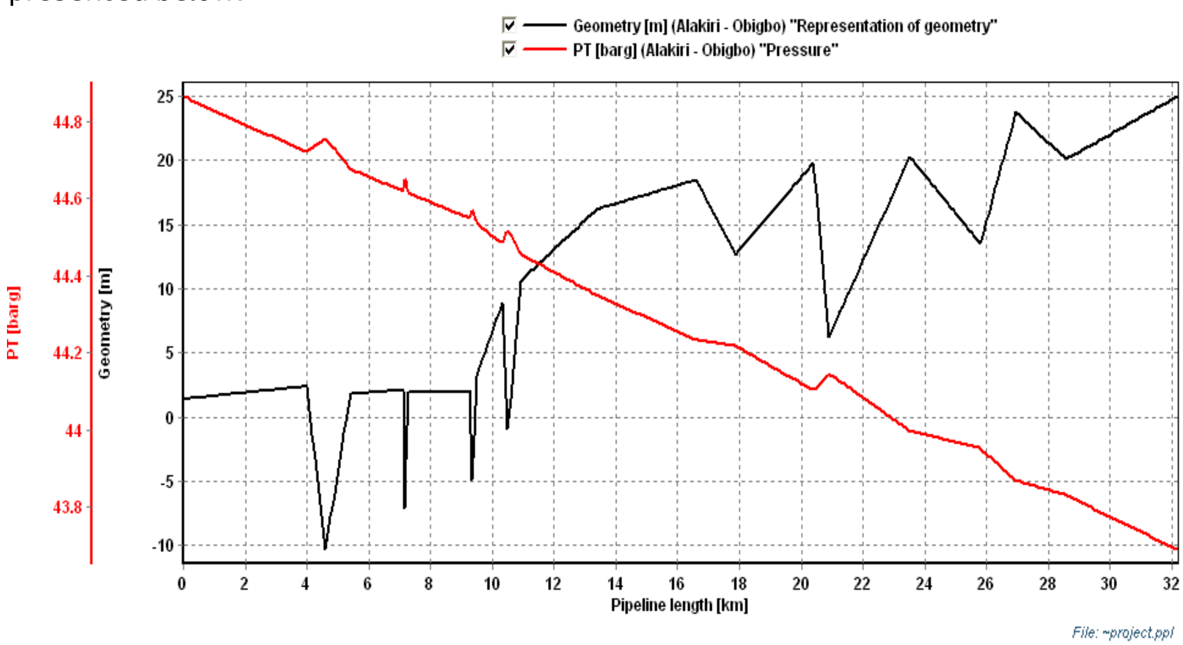

Figure 12. Pressure drop variation along Alakiri-Obigbo within the expected pressure

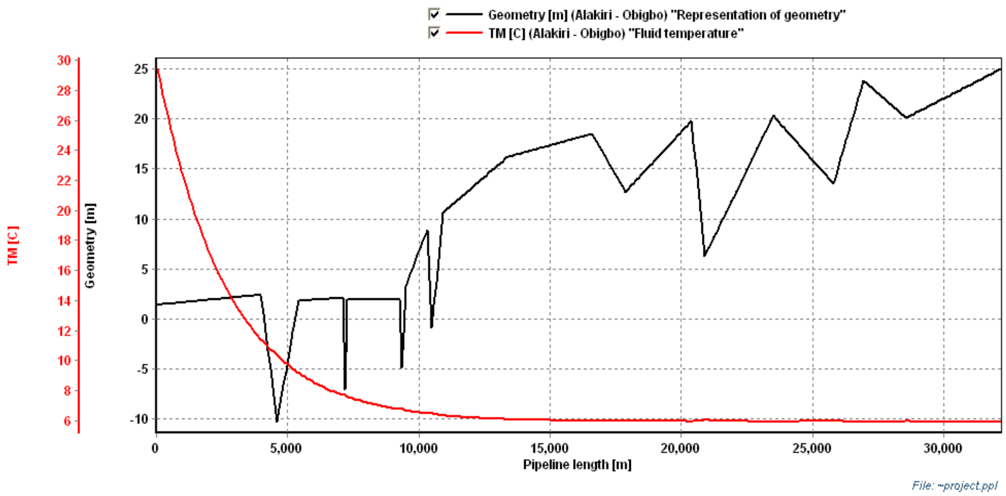

Figure 13. Temperature drop variation along Alakiri- Obigbo within the expected value

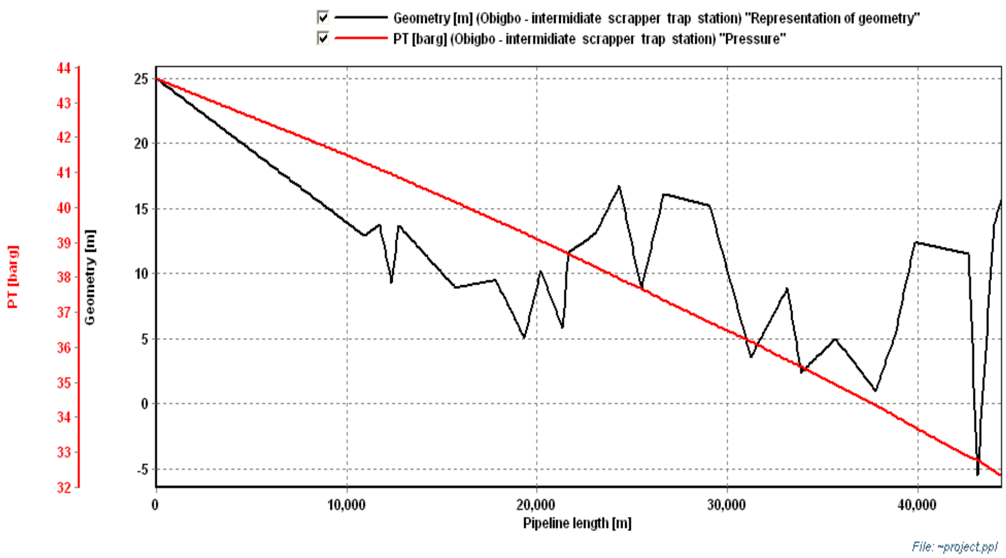

Figure 14. Pressure drop variation along Obigbo-intermediate scrapper trap station within expected value

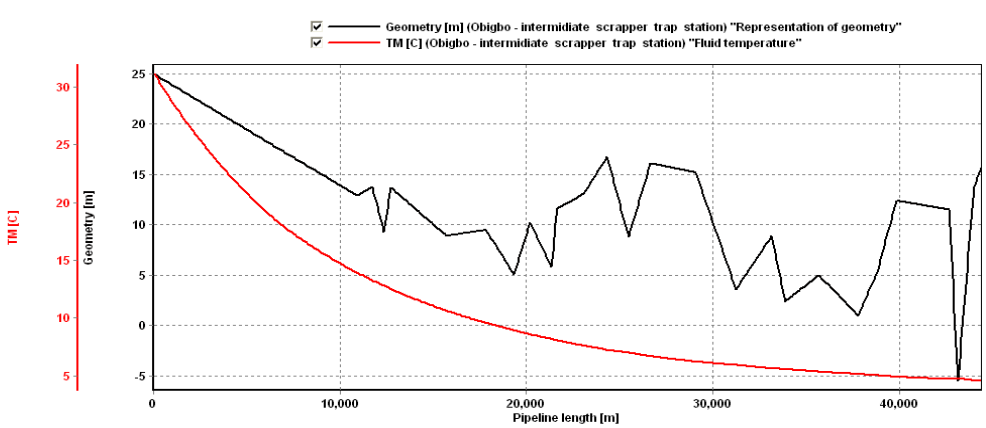

Figure 15. Temperature drop/variation along Obigbo-intermediate scrapper trap station within expected value

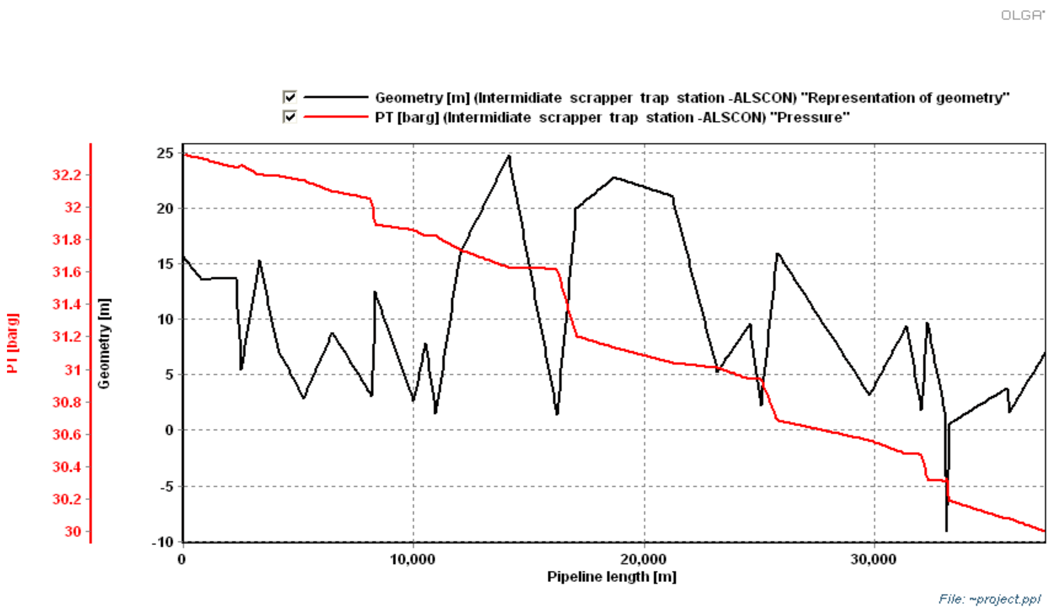

Figure 16. Pressure drop/variation along intermediate scrapper trap-ALSCON less than expected value

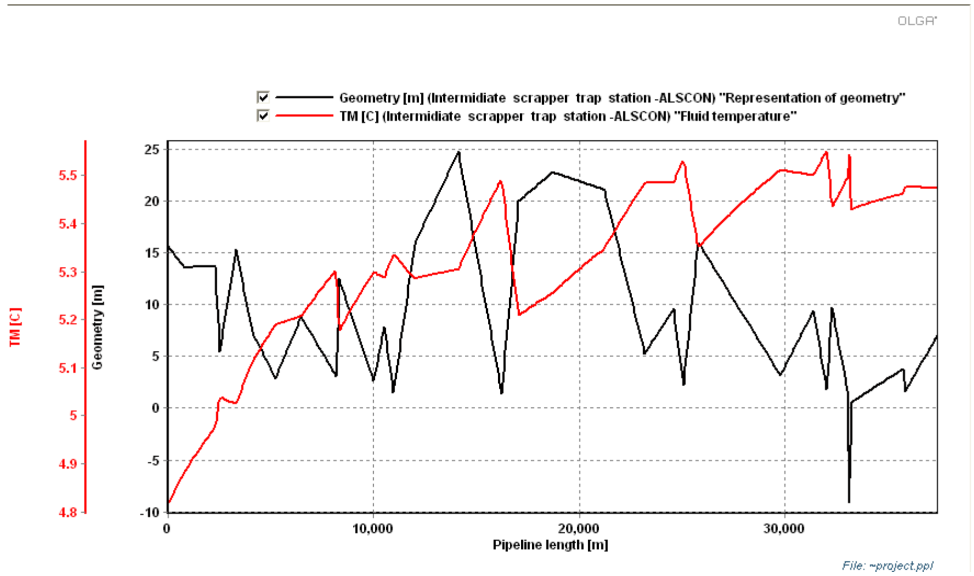

Figure 17. Temperature variation along intermediate scrapper trap-ALSCON less than expected value

Following the steady state analysis, based on gas flow rate of 100MMscfd at the ALSCON terminal. Also the system was designed for a minimum pressure of 25barg and minimum temperature of 20^{O}C at the ALSCON terminal. Other operating conditions are that the sources, Alakiri has temperature of 37.5^{0}C and Obigbo has temperature of 46.7^{O}C.

The simulation results when compared with the existing data indicates that the production system is operating within the pressure and temperature constraints for each platform and the set delivery values.

5.3. Investigating hydrate risks and determining hydrate formation potential during "no touch" time of 24 hours after shutdown

After running the hydrate check simulation in OLGA, the results are presented below:

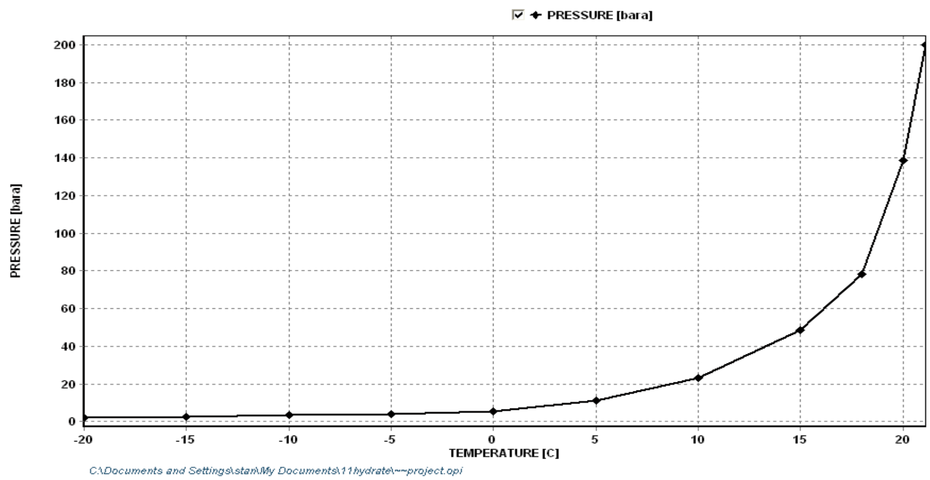

Figure 18. Hydrate curve

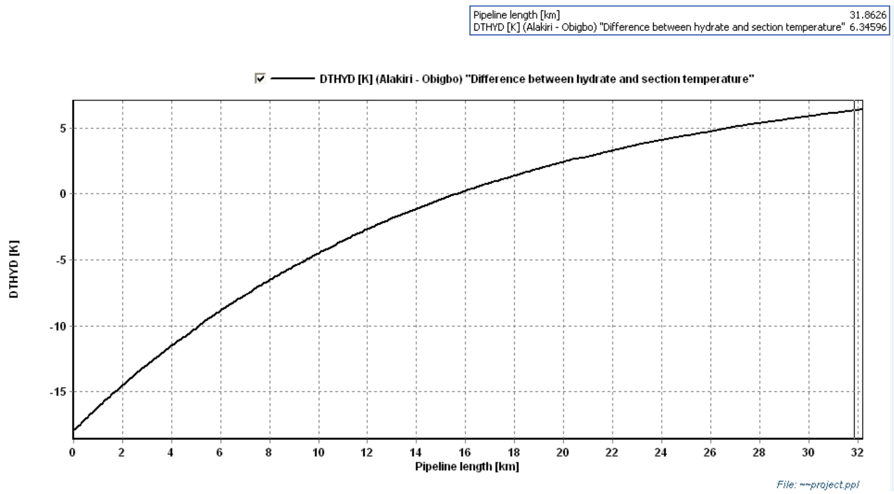

Figure 19. Alakiri – Obigbo different between Hydrate and section temperature

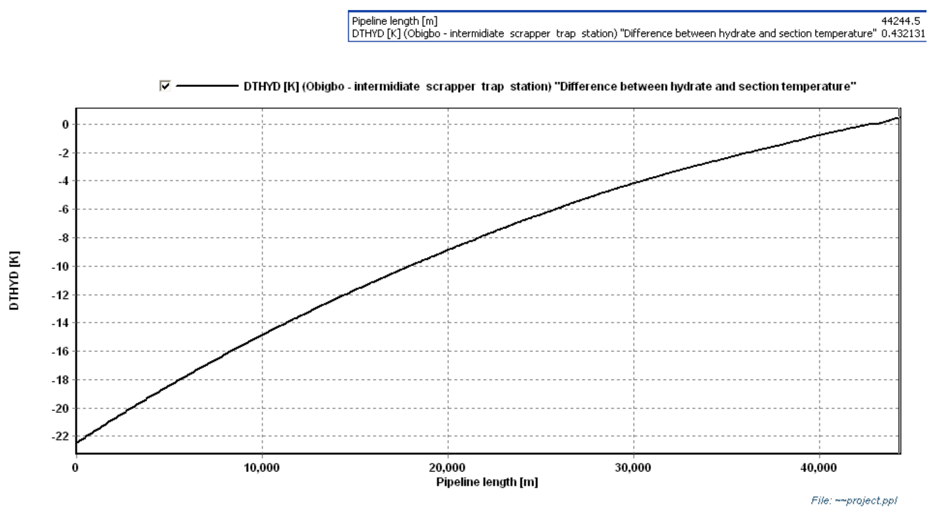

Figure 20. Obigbo - Intermediate scrapper Trapper station different between Hydrate and section temperature

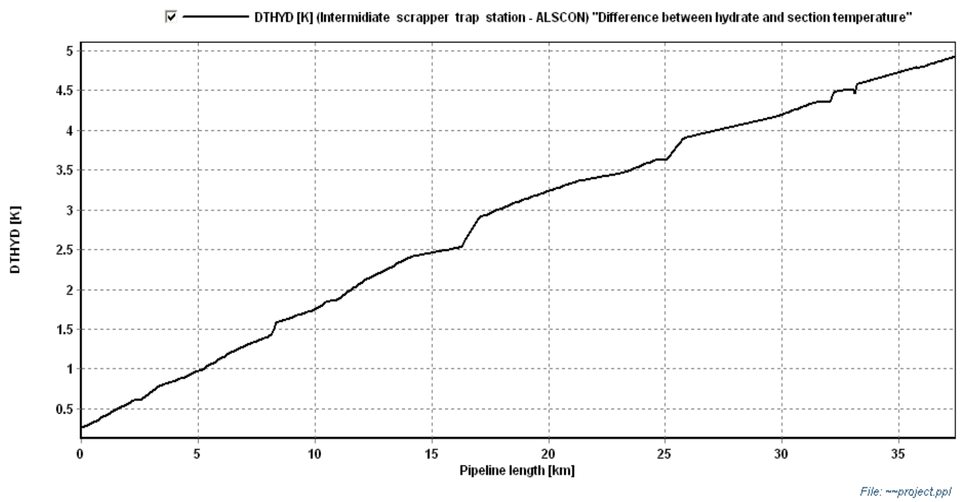

Figure 21. Intermediate scrapper trap station-ALSCON different between Hydrate and section temperature

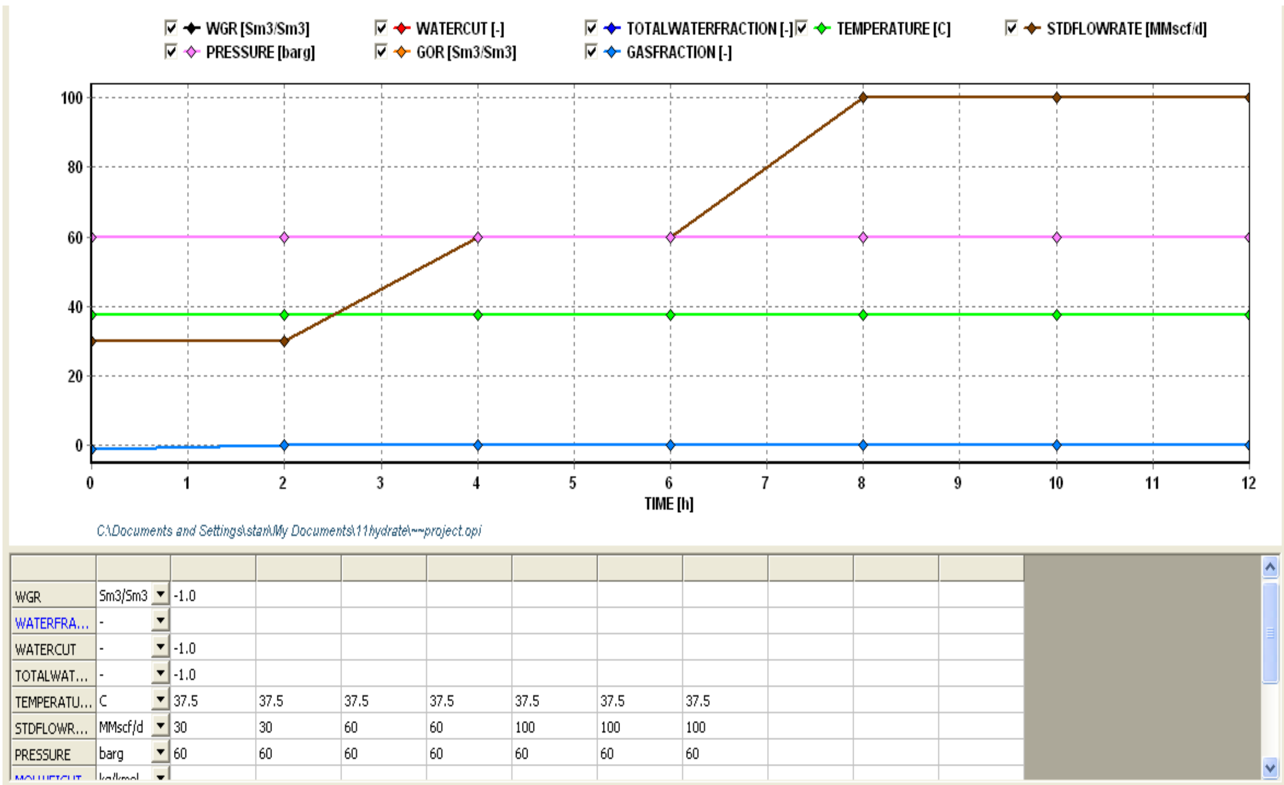

Figure 22. Alakiri Source Ramp-up

The entire pipeline segment from Alakiri - Obigbo-ALSCON was shut down after 12 hours. After a total shutdown period (no-touch time) of 24 hours.The fluid temperature for Alakiri - Obigbo pipeline segments as shown in Fig. 21 and that of Obigbo - Intermediate scrapper station pipeline segments shown in Fig. 22, indicates that they are above the hydrate formation (Difference between hydrate and section temperature is negative for these respective pipelines). Thus, the hydrate analysis before shutting down the plant indicates that no hydrate was form along Alakiri and Intermediate scrapper station. Hence, there is no risk of hydrate formation during the operations and the shutdown period. However, Figure 23 which represent the pipeline Segment 3 indicates the possibility of hydrate formation along

Intermediate scrapper trap station – ALSCON; if the temperature drops to hydrate formation temperature more often than segment 1 and segment 2. Hence, hydrate threat is envisaged during this shutdown period.

Ramp-up simulation was done based on turndown results, in an effort to return the pipeline back to its peak flow rate. However, in this simulation analysis the flow rate will be ramped up from 30MMscfd to 100MMscfd at the Alakiri source, and then ramped up from 100MMscfd to 160MMscfd at the Obigbo source respectively for 12 hours. To have a basis for surge volume calculation different withdrawal rates were considered. The aim of this simulation is to determine the liquid rate and surge volume into the ALSCON receiving facility at different withdrawal rate.

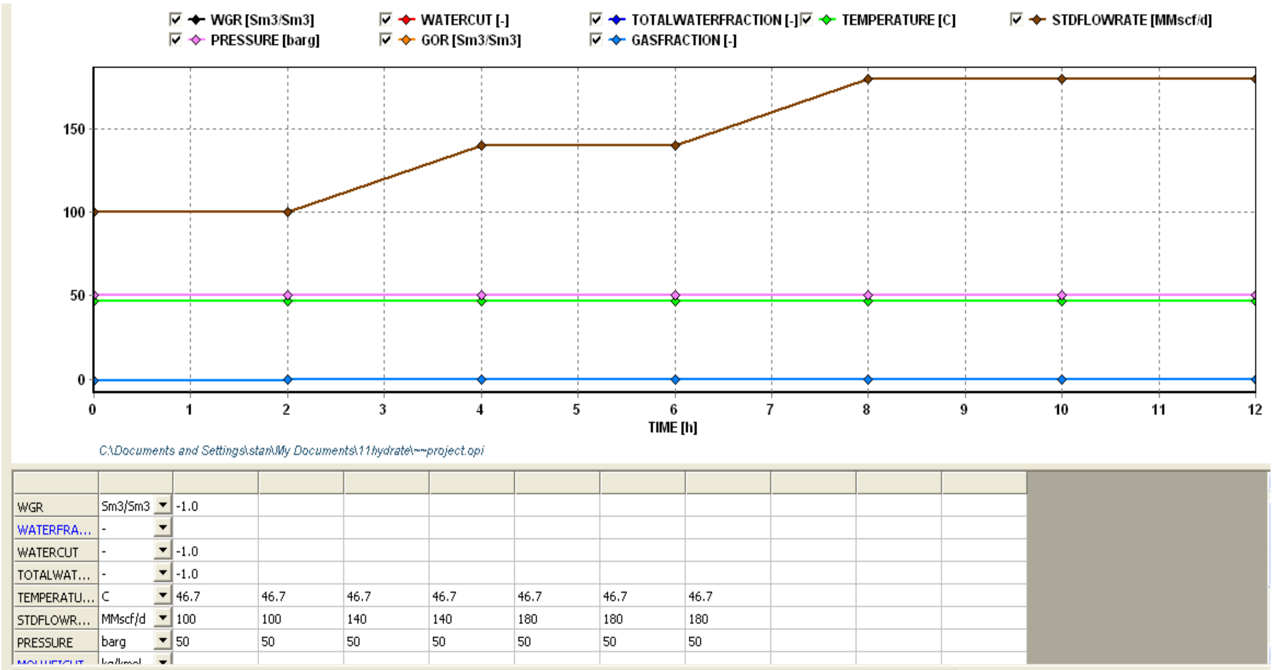

Figure 23. Obigbo Source Ramp-Up

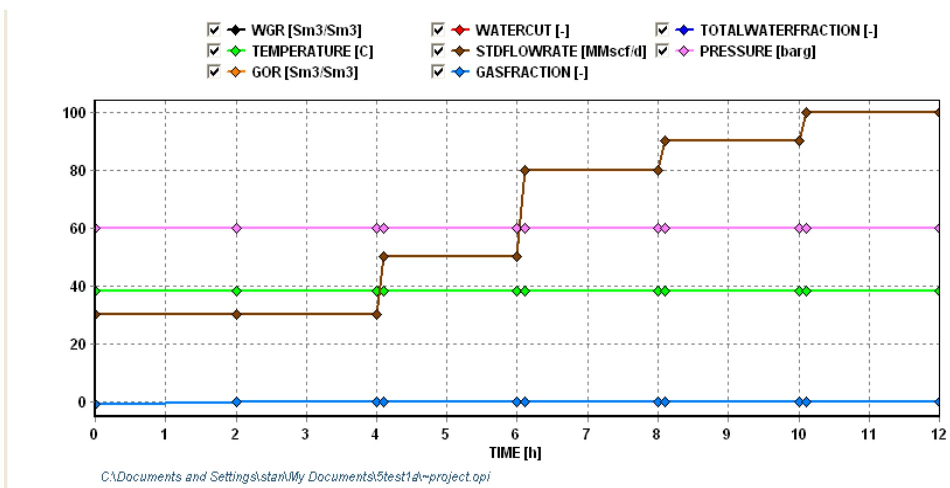

Figure 24. Ramp-up Alakiri Source

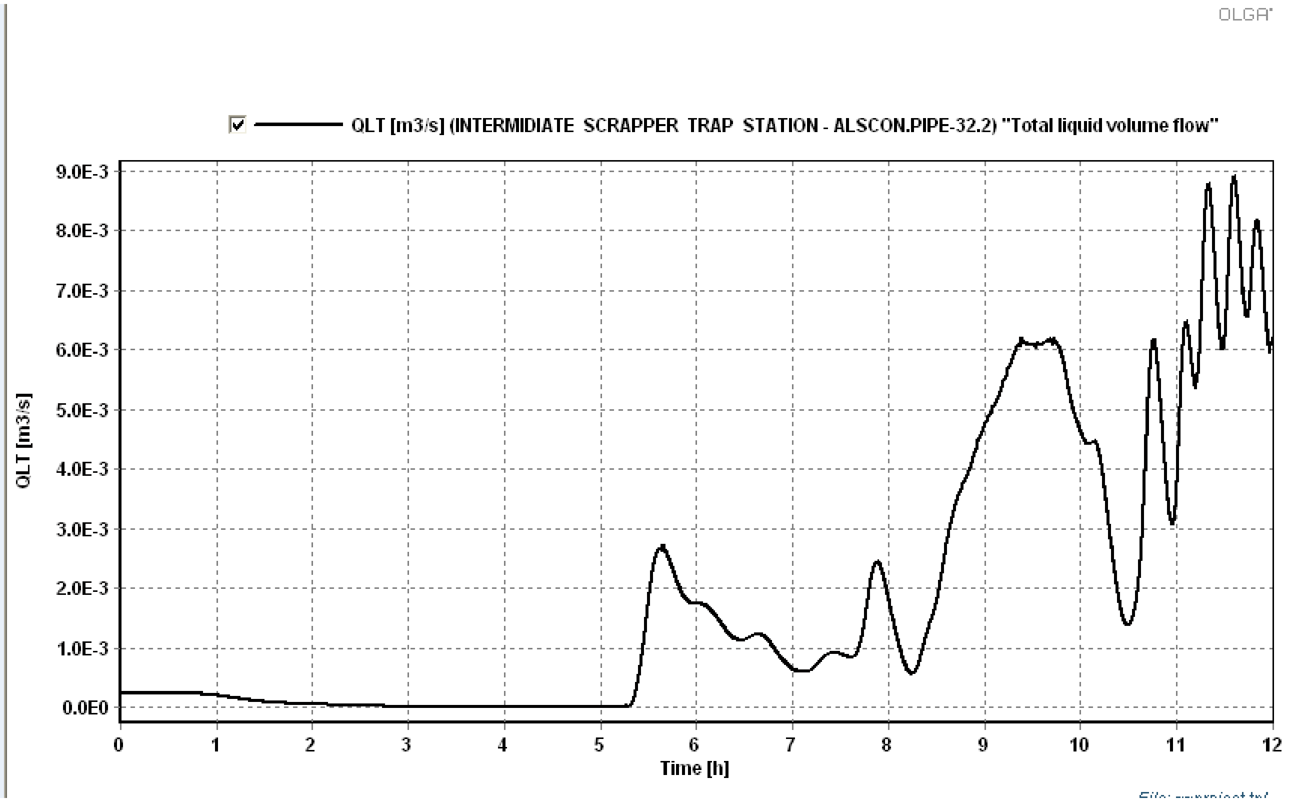

Figure 25. Total Liquid volume at ALSCON

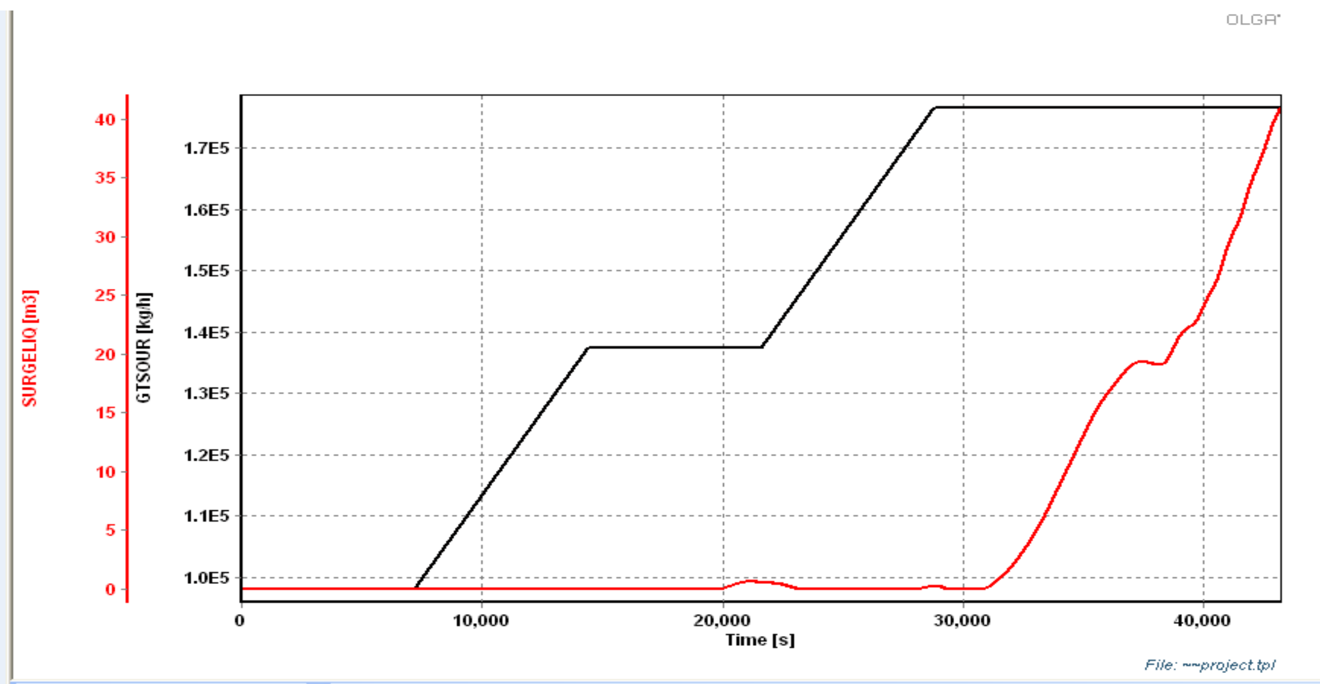

Figure 26. Obigbo Source mass rate and surge liquid volume for Intermediate scrapper trap - ALSCON

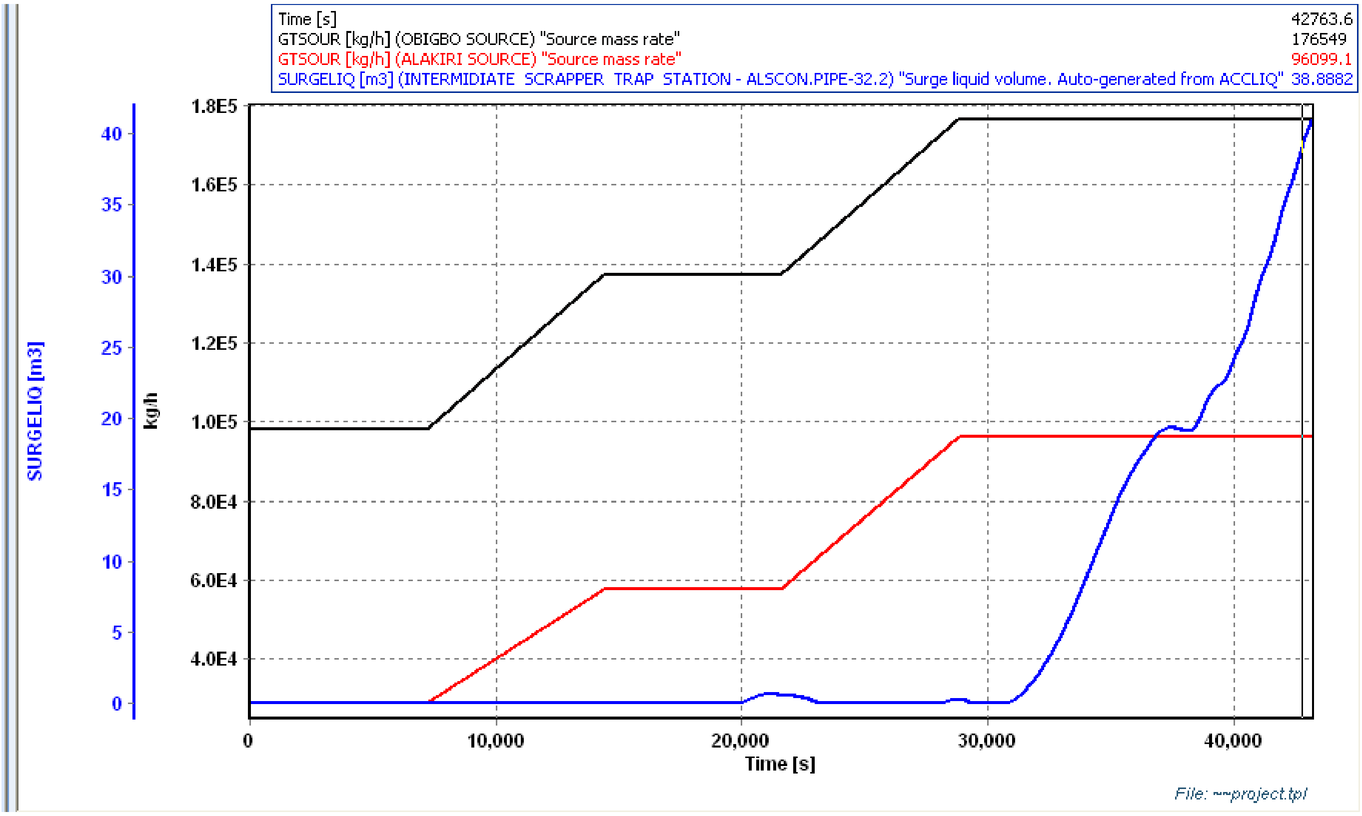

Figure 27. Alakiri Source and Obigbo mass rate and surge liquid volume for intermediate scrapper trap - ALSCON

From Figures 22 - 24, the flow rate was increase variably from 30MMSCFD to 100MMscfd at the Alakiri source while the Obigbo source was ramp up from 100MMscfd to 160MMscfd for 12 hours. Generally, lower ramp-up duration will result in rapid rate of liquid sweeping from the pipeline into the receiving facility to achieve the final flow rate of 160MMscfd.When the gas flow rate is increased, the higher gas velocity will sweep the lines for excess liquid contents. From Figures 28 and 29, we observed that the surge volume increases to 40m^3 at the ALSCON terminal. The surge volume is still within the limit of the recommended slug catcher dimension size of 83m^3.

Also, the pigging simulation using OLGA is intended to effectively remove condensate from the pipeline system and manage the liquid inventory associated with the maximum production rate. The aim of this pigging simulation is to determine the surge volume required at the ALSCON pipeline outlet to handle the liquid surge generated during the pigging operations. Pigging was performed on the ALSCON flow line. Prior to pigging, the ALSCON flow line has been flowing with gas from segment 1 and segment 2 at 100mmscfd. The pig was inserted at 90 minutes and the gas flow rate was kept steady at 100mmscfd.

The results are presented below:

Where: UPIG is the Pig velocity as defined by OLGA; ZZPIG is the pig's total distance travelled; SURGELIQ (liquid surge volume) is the required liquid surge capacity in the slug catcher.

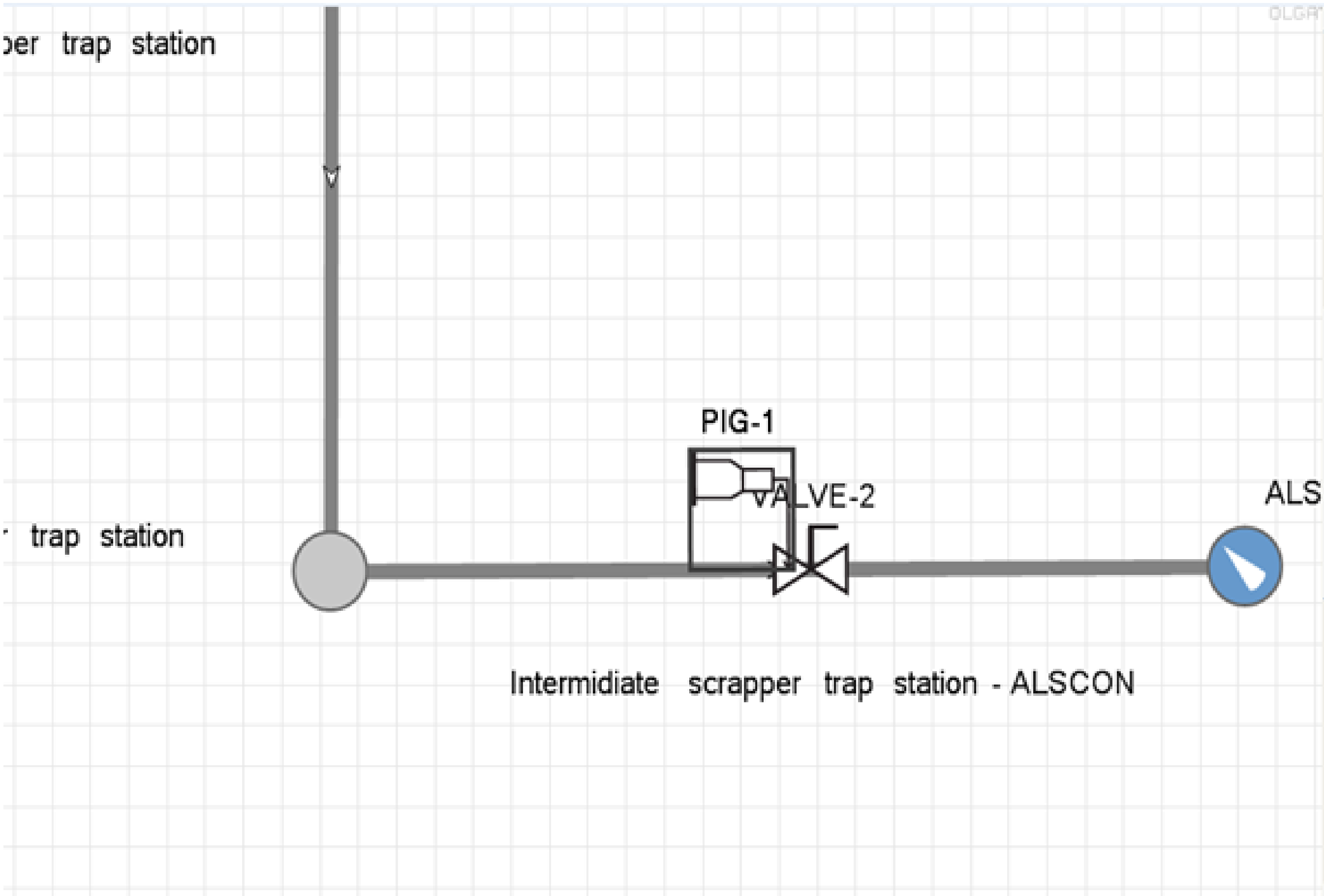

Figure 28. Pig model view 1

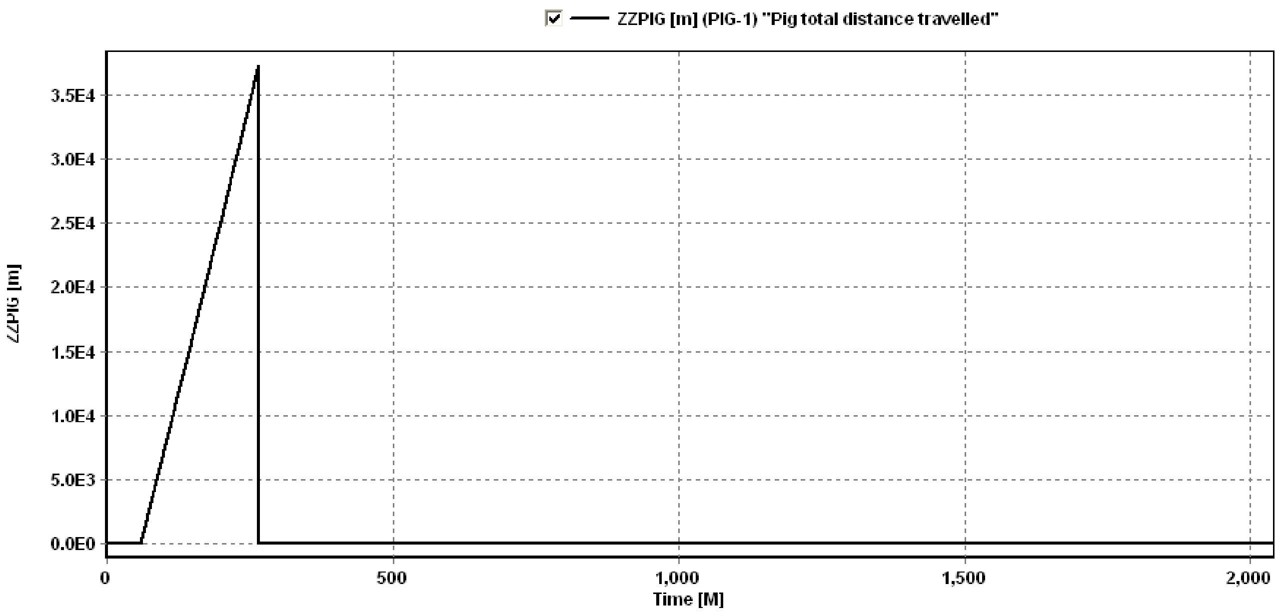

Figure 29. Pig trend plot of ZZPIG to determine when the pig reaches the trap

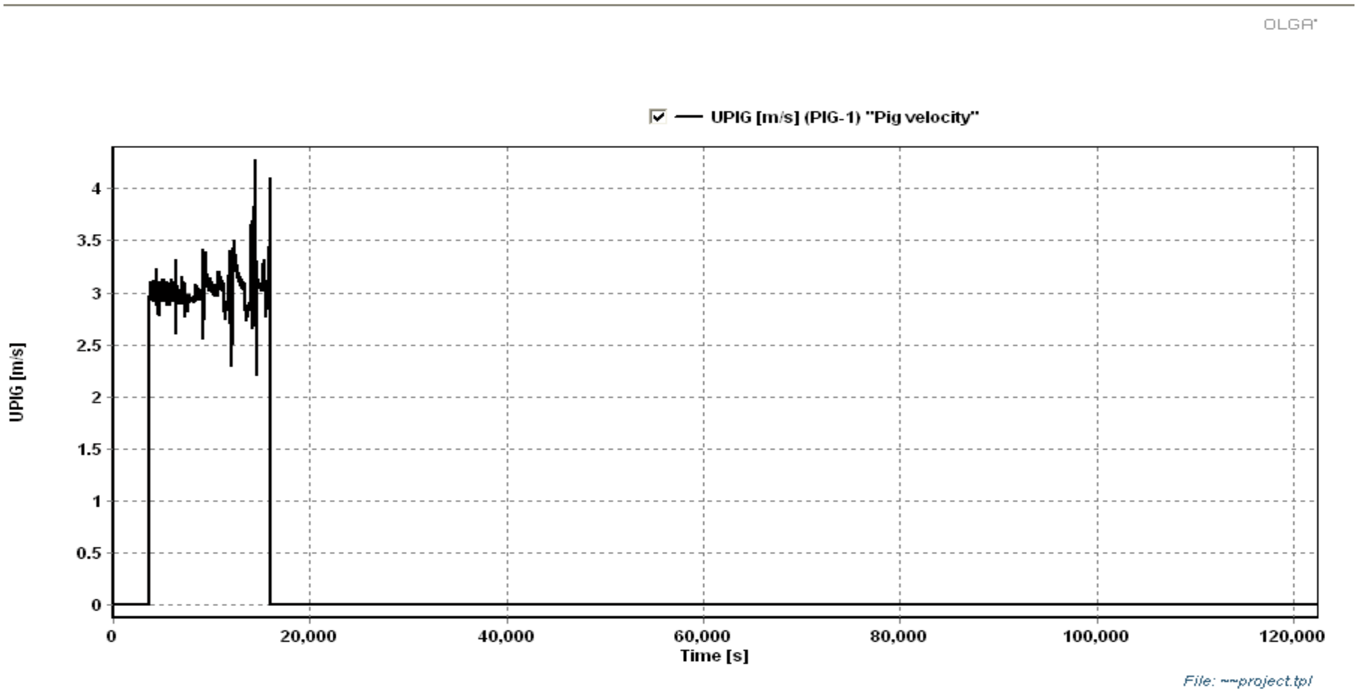

Figure 30. Pig velocity plot to determine the travelling velocity of the pig

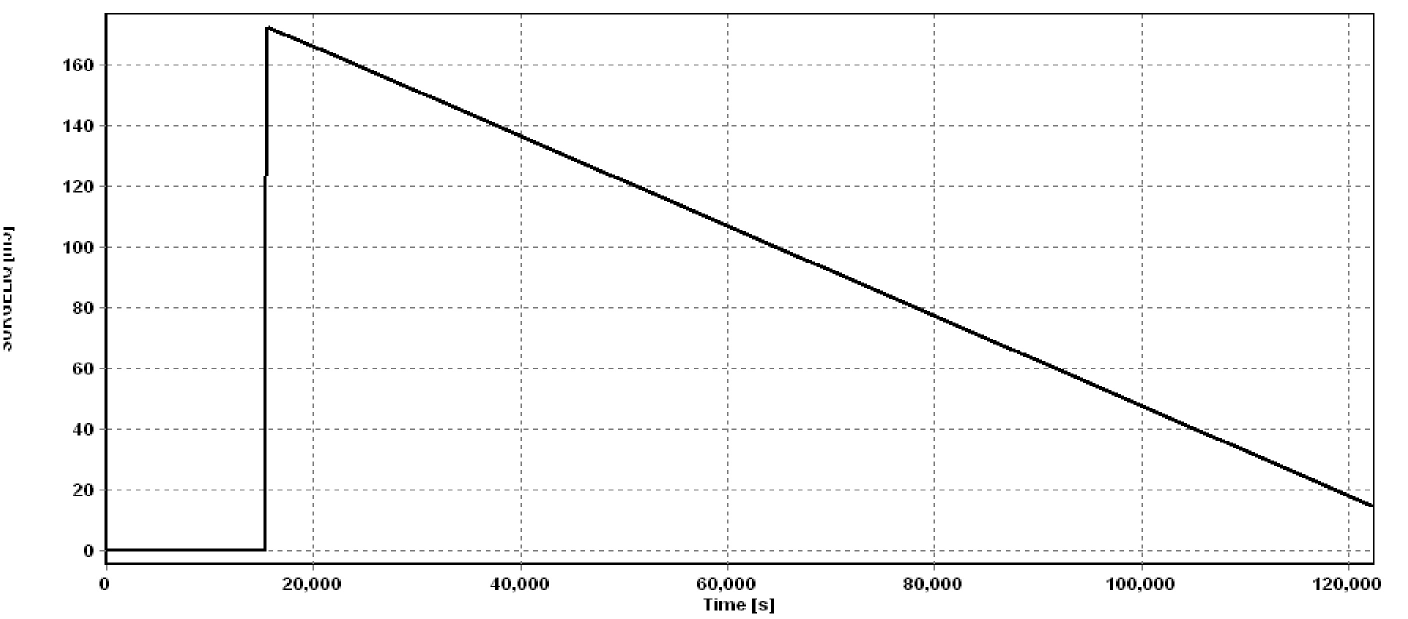

Figure 31. Plot of surge volume to determine the maximum pigging surge volume

From Figure 29, we observed that the pig reached the trap at approximately 266 minutes or 4.33 hours of simulation. The pig travelling time was verified by plotting the pig velocity as shown in Fig. 32. From the analysis shown in Figure 33, the maximum surge volume evaluated was 190m^3 with a corresponding pig velocity of 4.1m/s. During the pigging operation the liquid contents in the flow line increase and expel to the slug catcher as shown in Figure 34.

From the foregoing analysis, it can be concluded that the maximum surge volume dimension of 100m^3 and pig velocity of 4.1m/s values were not within the constraint for the slug catcher which was dimension for 83m^3.

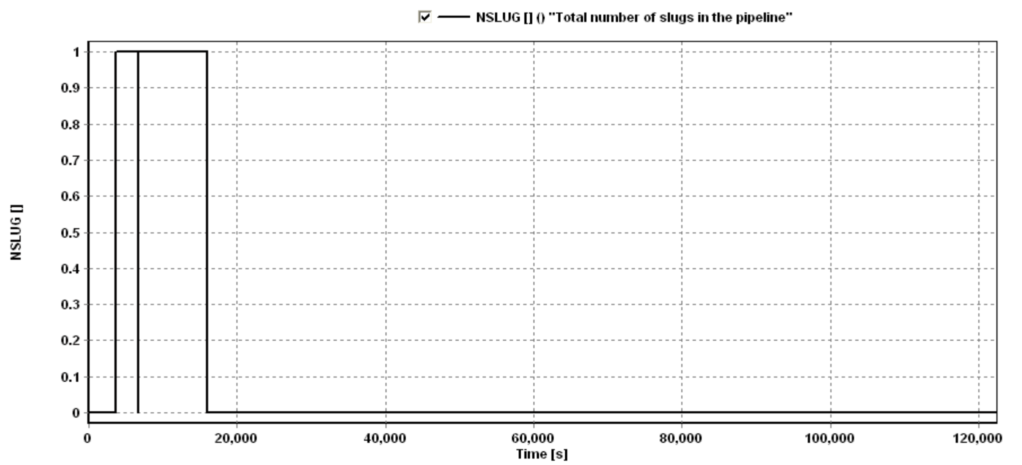

Figure 32. Plot of NSLUG to determine the total number of slugs in the pipeline

6. Conclusion

The research focus was on the Alakiri - Obigbo tie-in- Ikot Abasi, supplying gas to the Aluminum Smelter Plant (ALSCON) at Ikot Abasi. As designed, the pipeline network is about 114km which comprises of three pipeline segments.

From the phase envelope investigations, the natural gas composition used which is hydrocarbon wet suggesting two phase fluid. From the simulations the result indicates that the cricondentherm are within the constraint of the of the delivery temperature, since the cricondentherm is lower than the delivery temperatures for Alakiri and Obigbo. From the steady state analysis based on the gas flow rate of 100MMscfd at ALSCON receiving station, the production operating system is within the temperature and pressure constraints for each platform and the set delivery values, which is necessary to keep the pipeline insulation capable of preventing hydrate formation.

From the slugging analysis, hydrodynamic slugging will not be predominant for the pipeline operations at the design flow rate of 30MMscfd along Alakiri –Obigbo, and at 70MMscfd along the Obigbo Tie-in - Intermediate scrap station respectively, as the flow regimes are mainly stratified for both pipeline systems. However, slugging tendencies will be pronounced during turndown. Conversely, the Intermediate scraper trap-ALSCON pipeline segment with gas flow rate 100MMscfd is predominantly operating in the hydrodynamic slug flow regime. Therefore, this pipeline is operating under an unstable condition.

From the hydrate analysis investigated, after a shutdown period (no-touch time); hydrate threat is envisaged during the shutdown period of the Intermediate scraper trap – ALSCON along pipeline system, since the temperature drops to the hydrate formation temperature.

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