

Advanced PIPEPHASE Training Problems

Problem 1:

It is desired to calculate the crude oil heat exchanger network pressure profile and utilize the features of multiple piping devices and assay characterizations in PIPEPHASE.

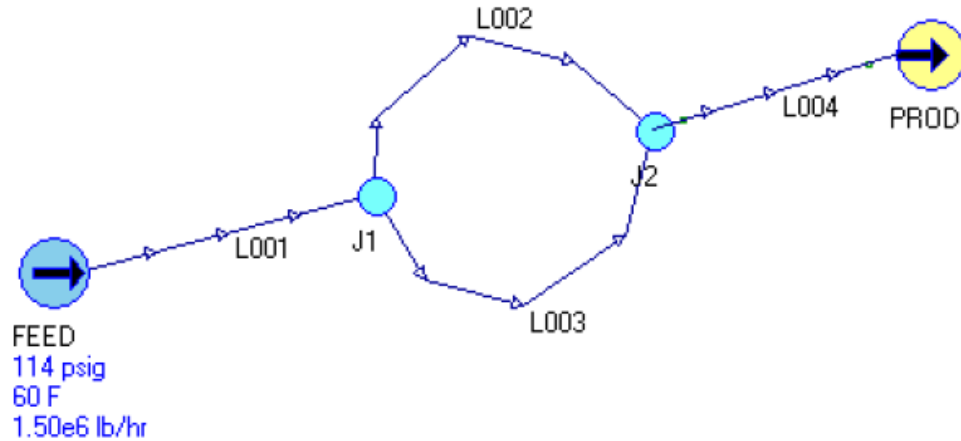


Table 1 shows the light-end component data. Table 2 shows assay curve data. Table 3 shows the pipeline system data.

Table 1: Light End Component Data	
Component	LV %
C2	0.1
C3	0.2
IC4	0.3
NC4	0.7
IC5	0.5
NC5	1.2
Total Percent in Assay	3.0

Source Distillation Data

Mandatory Data

Basis: Liquid Volume Gravity Type: API

Distillation Type: TBP Average Gravity: 31

Distillation Curve...

Light-Ends

Rate Basis: Liquid Volume

Composition Basis: Liquid Volume

☒ Percent of Total: 3 %

☐ Total Std. Flowrate: 3 bbl/hr

Gravity Curve...

Average Molecular Weight:

Molecular Weight Curve...

Light Ends Composition...

OK Cancel Help

Table 2: Assay Distillation Curve

Percent (LV%)	Temperature (°F)
3	97
5	149
10	208
20	330
30	459
40	590
50	690
60	770
70	865
80	980
100	1100
Average Density	31 API
Source Pressure	114 psig
Source Temperature	60 °F
Source Flowrate	1.5×10^6 lb/hr

Please use the **Grayson-Streed** thermodynamic method for the system. Use the **Lee-Kesler** assay characterization method for petroleum assay conversion and enthalpy calculation. Use the Superheated method for water decant and enthalpy calculation.

CASE STUDY 1

Change the source FEED pressure to 125 psig.

CASE STUDY 2

Change the source FEED pressure to 114, and pipe inside diameter in all link to 12 inches.

Table 3: Link Data			
Links	Devices Number	Devices Name	Specified Parameters
L001	Z001	PIPE	LENGTH=20, ID=12
	Z002	TEE	ID=12, KMUL=20, ROUGH (REL)=0.0001
	Z003	PIPE	LENGTH=20, ID=10
	E1	DPDT	FLOWRATE (LB/HR)=500,000; 1,500,000 DP (PSIG)=-10; -5 DT (°F)=50; 40
	Z005	PIPE	LENGTH=20, ID=10
	Z006	VENTURI	ID=12, IDTHROAT=9.5 CPCV Ratio = 1.45
	Z007	CONTRACTION	IDIN=12, IDOUT=10, ANGLE=135
	Z008	PIPE	LENGTH=5, ID=10
L002	Z009	PIPE	LENGTH=10, ID=10
	Z010	BEND	ID=10, KMUL=60 ROUGH(REL)=4.471e-004
	Z011	PIPE	LENGTH=40, ID=10
	E2	DPDT	Same as E1
	Z013	PIPE	LENGTH=20, ID=10
	Z014	ORIFICE	Thick, IDPIPE=10, IDORIFICE=6
	Z015	PIPE	LENGTH=20, ID=10
	Z016	BEND	ID=10, KMUL=60 ROUGH(REL)=4.471e-004, HOMOGENEOUS
	Z017	PIPE	LENGTH=10, ID=10
L003	Z018	PIPE	LENGTH=10, ID=10
	Z019	BEND	ID=10, NONSTANDARD ANGLE=60, RADIUS=30, KMUL=50 ROUGH(REL)=4.471e-004
	Z020	PIPE	LENGTH=40, ID=10
	E3	DPDT	Same as E1
	Z022	PIPE	LENGTH=40, ID=10
	Z023	BEND	ID=10, KMUL=60, ROUGH(REL)=4.471e-004, Standard 90° Elbow
	Z024	PIPE	LENGTH=10, ID=10
L004	Z025	PIPE	LENGTH=5, ID=10
	Z026	EXPANSION	IDIN=10, IDOUT=12, ANGLE=135
	Z027	PIPE	LENGTH=40, ID=12
	E4	DPDT	Same as E1
	Z029	PIPE	LENGTH=40, ID=12

Problem 2:

Wet gas is produced offshore and subsequently transported to shore through a 32-inch pipeline. As shown in Figure 1, the wet gas passes through a booster platform where the gas is separated and compressed. This gas is then re-combined with the condensate and sent to the onshore destination. The process conditions are given in the following Tables.

You are required to:

1. Determine the onshore slug catcher size. To do this, you must calculate the onshore fluid temperature, pressure, liquid and vapor rate, and total liquid holdup.
2. Generate fluid phase envelope and hydrate curves. Assuming that the average seabed temperature is 10°C, you are assigned to determine if hydrate will form in the line by using PIPEPHASE's point by point hydrate prediction cap.

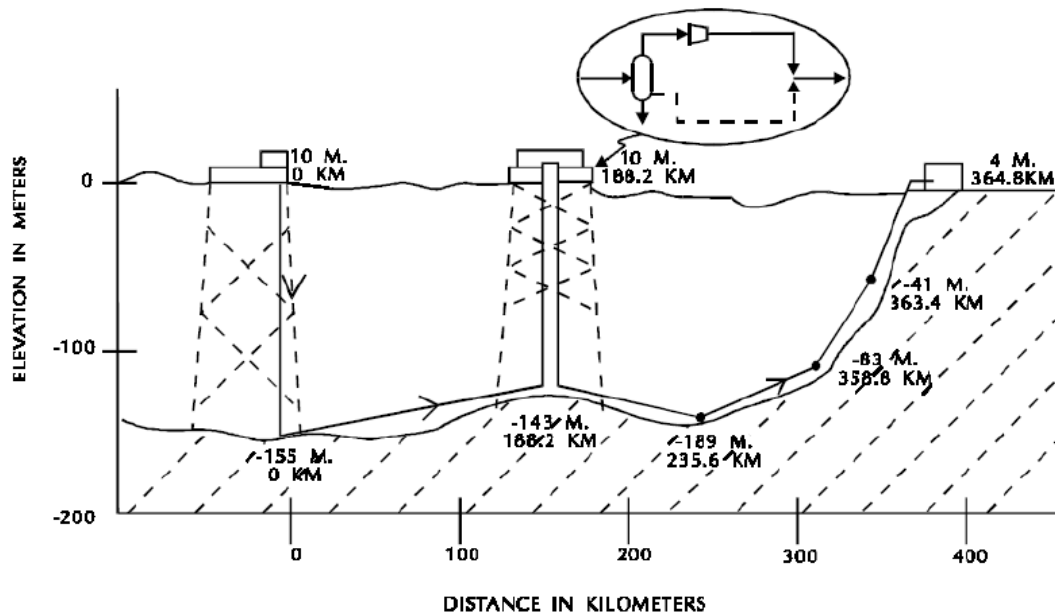


Table 1 gives the pipeline data. Table 2 provides the heat transfer data. Table 3 shows the Fluid Rate and Compositions.

The source pressure is 140 bar and temperature is 47 °C. The source flowrate is estimated as 1 MMkg/hr. The compressor is set as 120 bar outlet pressure and 85% efficiency.

Metric units of measure are used throughout the simulation. Selected data are input using petroleum units of measure.

Rigorous heat transfer for submerged pipeline is necessary for simulating gas condensate pipeline in cold environments.

Compositional analysis using library components provides accurate phase behavior and

fluid properties. A phase envelope is generated. The envelope also shows the fluid path. The SRK equation of state for all PVT is used for accurate modeling of gas condensates. Compositional separator and re-injection are easily simulated.

The Taitel-Dukler-Barnea flow regime predictor is used to accurately predict the flow pattern.

Holdup, velocity, temperature, pressure and fluid property details are requested in the output report.

Link pressure, link temperature and phase envelope plots are requested in the output report.

The Beggs and Brill-Moody correlation was chosen for pressure drop and holdup calculations.

Since the vertical pipes are not insulated, heat transfer coefficients of 0.25 Btu/ft²-hr-F and 1.6 Btu/ft²-hr-F are assumed for heat loss to air and water respectively.

A roughness factor of 0.056 mm is used for all pipe sections.

Table 11: Pipeline Data	
Parameter	Values
Inside Diameter	30.5 inches
Wall Thickness	19.05 mm
Insulation Thickness	1.8 inches
Pipe Roughness	0.056 mm

Table 12: Heat Transfer Data	
Parameter	Values
Water Temperature	10 °C
Normal Water Velocity	5 km/hr
Insulation Conductivity	0.4 Btu/ft-hr-F
No Other Data	Use Default

Table 13: Fluid Rate and Compositions	
Fluid Rate	10⁶ kg/hr
Component	Mole %
H2O	0.08
N2	0.19
CO2	2.07
C1	87.18
C2	4.93
C3	2.98
IC4	0.54
NC4	0.69
IC5	0.29
NC5	0.20
NC6	0.30
NC7	0.55

Add one hydrate module and input data as shown in the following figure.

Define Hydrate Calculation

Node Name: SRCE

Curve Specification: Pressure

Point Selection:

- ☒ Number of Points: 30
- ☐ Pressure Increment: bar abs

Initial Pressure: 2 bar abs

Final Pressure: 150 bar abs

Temperature Estimate for Initial Pressure: -25 C

Hydrate Inhibitor:

- ☒ Use Inhibitor
- MEOH
- Concentration Weight Percent: 10, 20, 30, 40

OK Cancel Help

Solutions

Partial output listings are shown at the end of this document; the following results were obtained:

- Onshore temperature 5.6°C
- Onshore pressure 73.39 bars
- Onshore liquid rate (in situ) 110.8 m³/hr
- Onshore vapor rate (in situ) 12.32 x 10³ m³/hr
- Total liquid holdup:
 - main to booster platform 3630.7 m³
 - booster platform to shore 5924.1 m³

The PIPEPHASE output shows a possibility of formation of type II hydrate below 22.3°C (about 26 kilometers from the inlet). To avoid hydrate formation, addition of a hydrate inhibitor should be considered.

Compositional runs provide flash reports at the inlet and outlet of the pipeline. These reports show a detailed breakdown of gas and condensate compositions and associated properties.

Compositional runs provide separator reports which show the main and separated stream compositions and their associated properties.

The device detail report shows that the offshore processing facility removes 642 Kg/hr of water. The compressor requires approximately 6300 Kw to increase the stream pressure to 120 bar.

A heat transfer coefficient of 14.4 kcal/hr-m²-C is calculated by the program for most pipe sections.

Plots of pressure and temperature profiles were requested. The pressure and temperature increases across the compressor are clearly shown. In addition, the Joule-Thomson temperature effect is evident.

The Taitel-Dukler-Barnea flow pattern map is also printed. The results indicate single-phase and stratified flow through most of the pipeline. The last vertical pipes are shown to be in annular or intermittent flow.

Figure 3:
Hydrates Results
No MeOH

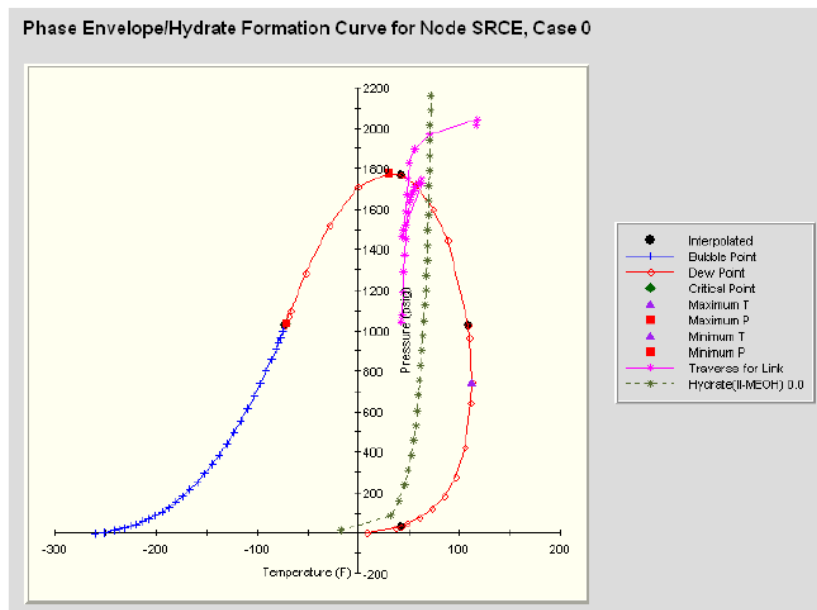
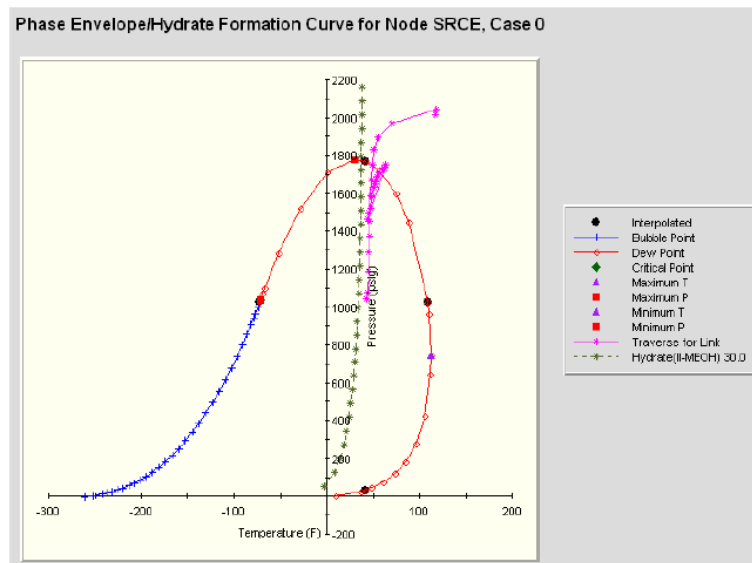


Figure 4:
Hydrates Results
30% MeOH



Problem 3: Pigging Analysis

A cross-country pipeline, which carries a two-phase natural gas mixture, is currently operating at its maximum capacity. The pressure at the end of the pipeline will become too low if the flowrate is increased and so additional compression will be required. Sphering, or pigging, is to be performed in order to increase the throughput of the line. Spheres will be launched at the beginning of the line and at two intermediate points along the line as shown in Figure 1. This exercise is to determine the quantity of liquid that will be removed from the pipeline in order to size the slug catcher.

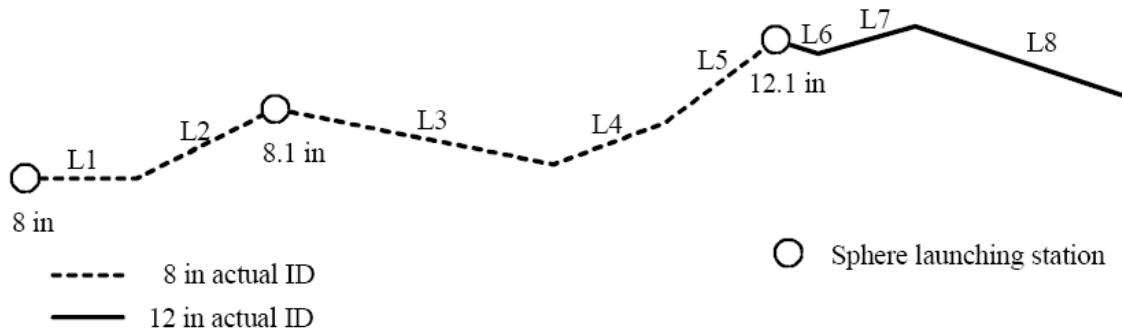


Table 1 gives the composition and conditions of the source fluid. Table 2 provides data for the higher-boiling components.

Table 8: Source Composition and Conditions	
Components	Mole %
C1	88.61
C2	3.15
C3	2.69
NC4	2.04
NC5	1.67
NC6	1.11
PETRO1	0.55
PETRO2	0.18
Pressure	350 psia
Temperature	120 °F
Gas Flowrate	0.7667 MMft ³ / hr

Table 9: Petroleum Component Properties		
Petroleum Component	Density (API)	Boiling Point (°F)
PETRO1	45	350
PETRO2	38	480

The pipe devices are summarized in Table 3. The pipe heat transfer coefficient is $0.8 \frac{\text{Btu}}{\text{hr ft}^2 \text{°F}}$. The ambient temperature is 65°F.

Table 10: Piping Segments		
Pipe	Length (ft)	Elevation Change (ft)
L1	4224	0
L2	6336	154
L3	8448	-69
L4	3696	100
L5	6336	120
L6	264	-10
L7	2640	58
L8	9504	-118

For initial sink estimates, use 1 lb/hr for flowrate and 10 psia for pressure.

How much liquid must be removed from the pipeline?

What is the length of the slug?

How long does it take for the slug to reach the end of the pipe?

How long does it take to re-establish steady-state?

Solutions

From the Sphering Report, you can see that the slug is 2,724 ft long when it reaches the end of the pipe. The slug is delivered in 181 sec (just over 3 minutes). Steady state flow is re-established 31,358 sec (8.7 hours) after the sphere is launched.

The latter parts of the Sphering Report is shown below.

-----SLUG ZONE-----					
SLUG	SLUG	SLUG	PRESS:	EDGE	
TIME	VELO:	EDGE	PRESS:	DROP	DISTANCE
(SECS)	(FPS)	LENGTH	(PSIA)	(PSIA)	(FT)
-----	-----	-----	-----	-----	-----
1606.8	13.95	2444.6	252.2	21.0	38517.0
1625.2	13.86	2443.3	254.0	20.8	38658.3
1643.7	13.86	2471.7	253.6	21.0	38932.1
1662.2	13.87	2500.3	253.3	21.2	39206.2
1680.6	13.87	2529.0	252.9	21.5	39480.7
1699.1	13.87	2558.0	252.5	21.7	39755.6
1717.6	13.88	2587.0	252.2	21.9	40030.8
1736.0	13.88	2616.1	252.0	22.0	40306.4
1754.5	13.88	2645.4	251.8	22.1	40582.4
1773.0	13.81	2647.0	253.5	21.8	40723.6
1791.5	13.81	2676.5	253.3	21.9	40998.3
1809.9	13.82	2706.0	253.1	22.0	41273.4
1819.2	13.82	2720.7	253.0	22.0	41410.9
1821.5	13.82	2724.4	253.0	22.0	41445.4

SLUG DELIVERY			

TIME	SLUG	SPHERE	PRESS:
(SECS)	VELOCITY	VELOCITY	BEHIND
-----	-----	-----	-----
9.8	13.89	13.89	274.9
19.6	13.89	13.89	273.6
29.4	13.89	13.89	272.4
39.2	13.93	13.93	271.3
48.9	14.00	14.00	270.6
58.6	14.06	14.06	269.6
68.3	14.11	14.11	268.6
77.9	14.16	14.16	267.6
87.5	14.22	14.22	266.5
97.0	14.27	14.27	265.4
106.5	14.33	14.33	264.3
116.0	14.39	14.39	263.2
125.4	14.45	14.45	262.1
134.8	14.51	14.51	260.9
144.2	14.57	14.57	259.8
153.5	14.63	14.63	258.6
162.7	14.70	14.70	257.3
172.0	14.77	14.77	256.1
181.1	14.84	14.84	254.8

Problem 4 Dense Phase CO2 Pipeline

This is an exercise which depicts an injection system. The fluid is basically CO₂ with a little nitrogen, methane and ethane in it. It is known that CO₂ is transported most efficiently in the dense phase, so it is required that the conditions everywhere in the system satisfy this criterion. It is desired to determine the flow delivered to each well subject to the dense phase constraint. Accurate phase and property prediction are necessitated because of the nature of CO₂ dominated mixtures under these constraints. Please use BWRST thermodynamic method for the system.

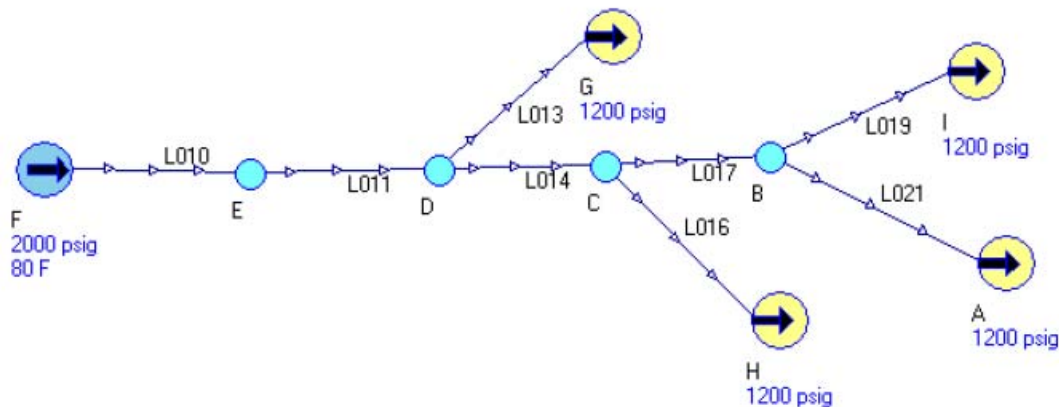


Table 1 shows the process data in the system. Table 2 shows the source compositions, and Table 3 shows the pipeline data.

Table 5: Temperature Data		
Name	Value	UOM
Ambient Temperature	80	°F
Source (F) Fixed Pressure	2000	psig
Sink (G, H, A, I) Fixed Pressures	1200	psig
Flow Estimate at Source F	170	MMft ³ /day
Flow Estimate at Sink G	700,000	lb/hr
Flow Estimate at Sink I	500,000	lb/hr
Flow Estimate at Sink A	500,000	lb/hr
Flow Estimate at Sink H	200,000	lb/hr

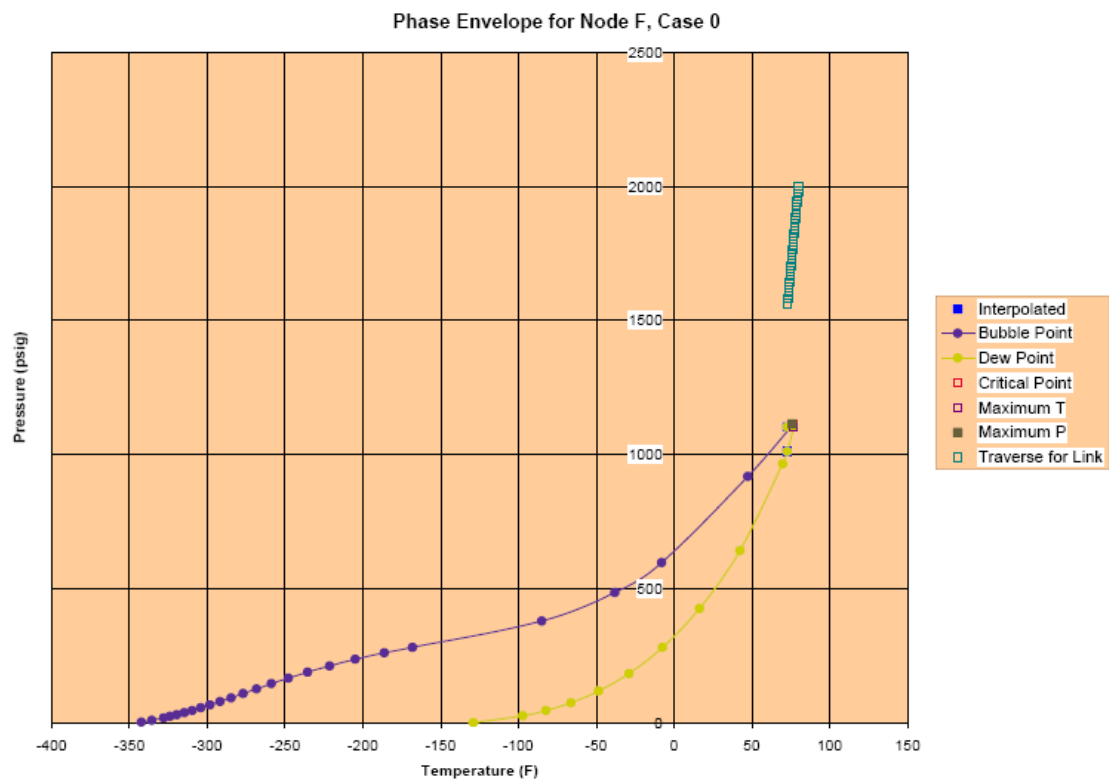
Table 6: Source Compositions

Components	Mole%
H2O	0.01
CO2	85.7
N2	2.86
C1	5.95
C2	5.48

Table 7: Pipeline Data

Links (From – To)	Length (ft)	Actual Diameter (in)
F – E	140,000	28
E – D	115,000	30
D – G	16,000	14.875
D – C	5,000	22.375
C – H	33,000	11.875
C – B	3,000	18.625
B – I	3,000	18.625
B – A	70,000	18.625

Result Phase Envelop



NOTES: Composition from upstream Node F.