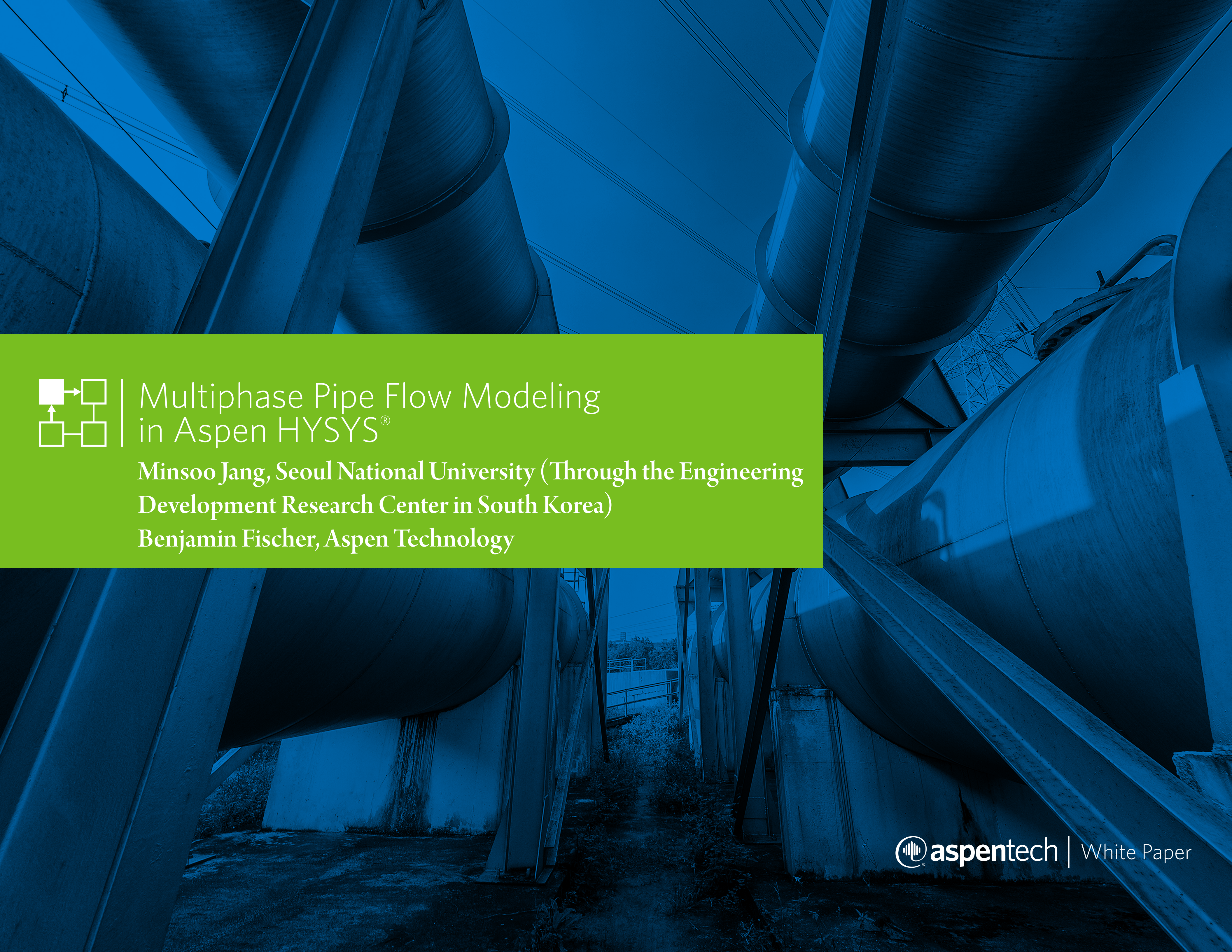

Multiphase Pipe Flow Modeling in Aspen HYSYS®

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Multiphase flow through pipes is characterized by the flow regime, liquid hold-up and pressure gradient. Accurate prediction of these flow attributes is necessary for designing and maintaining pipelines and flowlines in the oil and gas industry. Aspen HYSYS provides a number of flow correlations for modeling multiphase pipe flow. Unfortunately, there are not many published studies, and therefore not many recommendations, on the applicability of these different correlations for different conditions. Consequently, it is necessary for the user to perform studies to determine the appropriate correlation for their system.

To aid the user and provide a basis for comparison, the performance of correlations for different pipeline geometries, fluids, and flow regimes was analyzed. Simulation results from different flow correlations in Aspen HYSYS were compared with an experimental database provided by the Tulsa University Fluid Flow Project (TUFFP). In general, the Tulsa Unified Model performed the best in accurately predicting the flow regime, liquid hold-up and pressure gradient across the range of experimental conditions. This is not too surprising, as it is based on first principles and is therefore expected to perform across a broad range.

The Heat Transfer and Fluid Flow Service (HTFS) method, which is also mechanistic, predicted the pressure gradient well for the different geometries, but the liquid hold-up calculations did not agree well with the experimental values. In the systems examined, the Beggs and Brill model, which is empirical, tended to over-predict the pressure gradient and did not reliably capture the flow regime and liquid hold-up. Additionally, the Aziz et al. model, which is only applicable to vertical geometries, performed the best in the vertical systems analyzed even though it is an empirically based model.

It should be noted that the comparisons are still on a limited range of data. Only two-phase systems were assessed because of the limited data for gas, oil and water systems. The flowing fluids were also limited and not actual hydrocarbon fluids typically found in oil and gas applications. In addition, the geometries such as pipe diameter and length were on the lab scale, so extrapolating to field and plant scale is uncertain.

Introduction

The advancement of multi-phase flow has created an enormous economic impact by overcoming environmental limitations in the oil and gas industry. It has made it possible to transport fluid mixtures over long distances without separation processes. For example, at the Con Nam Son field in Vietnam, the flow line length is 250 miles from shore to the processing site with only a simple water separation facility. Sending gas and oil together in that long flow line enabled cost savings for building the local processing unit. It also made it possible to operate deeper offshore rigs by remediating flow assurance issues. For example, more advanced production design has been preventing slug flow from appearing in long flow lines, which is an unwanted phenomenon as it creates significant pressure fluctuations.

Determining the pressure drop caused by multiphase flow through a pipe is an important component when designing a production system or gathering network. Numerous correlations, therefore, have been developed to estimate pressure drop and liquid holdup in multiphase pipe flow. None of the correlations developed have been shown to perform across all conditions because they are often developed using a specific set of experimental data; therefore, the choice of which correlation to use depends on the conditions the user is trying to model.

For example, if a correlation has been developed specifically for vertical flow, application of these correlations to horizontal flow would not give acceptable results. Consequently, Aspen HYSYS provides a selection of correlations so that the user can effectively model their situation. In this study, the predictions of several flow correlations in the Aspen HYSYS pipe model are compared to experimental measurements of the flow regime, pressure gradient and liquid hold-up.

Multiphase Pipe Flow Modeling

When multiphase flow through a pipe, the fluid phases can spatially arrange in a different manner depending on a variety of factors such as geometry and fluid properties. These different flow regimes, examples of which are shown in **Figure 1**, make developing and solving equations analytically that describe the phenomenon extremely difficult, if not impossible. Therefore, in practice, the multiphase fluid is treated as a homogeneous fluid, and an energy equation is evaluated for this hypothetical phase. This energy equation is often expressed as the total pressure gradient across the length of the pipe:

$$\frac{dp}{dL} = \rho_m g \sin\theta + \left(\frac{dp}{dL}\right)_f + \rho_m v \frac{dv}{dL}$$

The first term on the right-hand-side of the equation represents the pressure gradient caused by the gravitational force, where p_m is the fluid density, g is the gravitational constant, and θ is the inclination angle of the pipe. The second term is the irreversible pressure losses due to fluid friction. The final term describes the kinetic or acceleration component of the pressure drop and is proportional to the change in the fluid velocity. Depending on the situation, any of the terms can dominate the overall pressure drop across the pipe. For example, in a vertical oil well, most of the pressure drop is caused by the first gravitational term. Conversely, in a high-flow-rate gas well, the frictional and acceleration contributions will be significant.

As can be seen, the equation requires the fluid density. While the dependence on the fluid density is explicitly shown for the gravitational and acceleration terms, there is also an implicit dependence in the frictional term. It is therefore important to have an accurate estimate of the fluid density. In multiphase flow, the fluid density is based on the liquid hold-up in the pipe, which accounts for the fact that the different gas and liquid phases can move with different velocities. Therefore, a common practice is to use a correlation to estimate the liquid hold-up in the pipe segment.

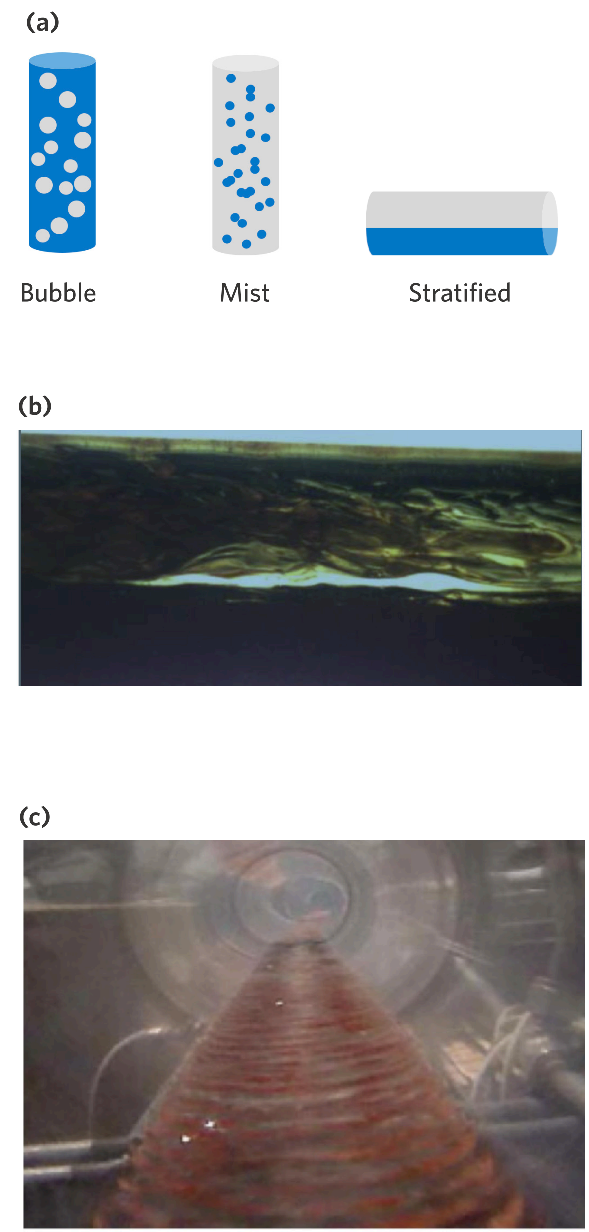

Figure 1: (a) Schematic examples of flow regimes in multiphase pipe flow. (b) Experimental flow regime formed during oil-gas flow1. (c) Stratified wavy flow pattern for oil-air flow2.

Similarly, correlations are often used to estimate the frictional component of the equation. As previously mentioned, the frictional component represents the irreversible losses caused by fluid friction. In multiphase flow, these losses are difficult to describe because more than one phase contacts the pipe wall and interfacial friction is generated between the phases. Estimation of these losses is also complicated by the non-uniform velocity distribution that often develops in multiphase flow.

Figure 2 depicts a flow diagram of how the pressure gradient is determined using a flow correlation. As a first step, the method may determine the expected flow regime such as a stratified flow of the gas moving on top of the liquid phase. The figure shows an example of the Mandhane flow regime map for horizontal flow. The identification of the flow regime may impact how the correlation determines the liquid hold-up and the frictional pressure loss.

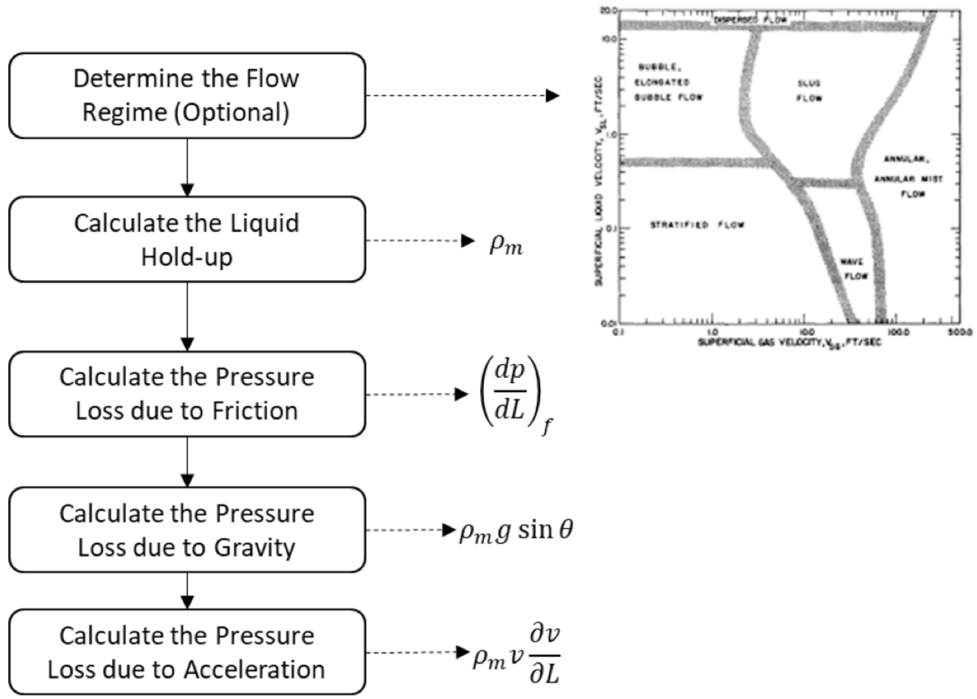

Figure 1: (a) Determining the pressure gradient for the flow of a multiphase fluid in a pipe. The flow regime map shown is from Mandhane,J.M., et al. (1997)

Correlations developed for the liquid hold-up and frictional pressure losses can be classified as empirical or mechanistic. Empirical methods are based only on experimental data. These are often fitted expressions using common dimensionless numbers such as the Reynolds number. As a result, they should not be applied across a broad range of flow conditions because they were developed under certain experimental conditions.

Alternatively, mechanistic methods have an analytical basis on first principles. Accordingly, they are often more successful with a wide range of data. However, there are often closure relationships that are based on experimental results so care still needs to be used when applying mechanistic models where they have not been validated. One potential issue with both empirical and mechanistic formulations that use flow regime predictions is that if the model is not continuous across the flow regime boundaries, then convergence issues can arise when using numerical methods to solve for the flow characteristics in pipelines.

Table 1 summarizes the correlations available in the Aspen HYSYS pipe segment and the Aspen Hydraulics sub-flowsheet. The "Pipe Geometry Applicability" column indicates whether each correlation can be used effectively in a certain geometry.

Correlation	Pipe Geometry Applicability			Category
	Hoizontal	Inclined	Vertical	
Tulsa Unified Model	O	O	O	Mechanistic
OLGAS	O	O	O	Mechanistic
Beggs & Brill (1973)	O	O	O	Empirical
Beggs & Brill (1979)	O	O	O	Empirical
Gregory et al.	O			Empirical
HTFS	O	O	O	Mechanistic
Aziz et al.			O	Empirical
Duns & Ros			O	Empirical
Orkiszewski			O	Empirical
Hagedorn & Brown			O	Empirical
Poettmann & Carpenter			O	Empirical
Baxendall & Thomas			O	Empirical
Lockhart & Martinelli	O			Empirical
Dukler	O			Empirical

Table 1: Flow correlations in Aspen HYSYS

Pipe Flow Experiments: The TUFFP Database

The Tulsa University Fluid Flow Project (TUFFP) is a cooperative research group between industry and Tulsa University that has been examining multiphase pipeline flow for more than 35 years. The experimental facilities include a flow loop that can handle two-phase air-water and air-oil flow and three-phase air-water-oil flow.

	Andritsos (1986)[4]	Yang (1996)[5]	Brill (1995)[6]	Fan (2005)[7]	Magrini 2009)[8]	Brito (2012)[9]	Caetano (1985)[10]
Number of Data Points	349	21	96	167	132	60	293
Working Fluids	Air/ Water	Air/ Kerosene	Air/ Kerosene	Air/ Water	Air/ Water	Air/ Oil	Air/ Kerosene
Pipe Diameter	0.0254, 0.0953 m	0.0508 m	0.0779 m	0.0508 m	0.0762 m	0.0508 m	0.0634 m
Pipe Angle	0° (Horizontal)	0° (Horizontal)	0° (Horizontal)	-75°-75°	0°- 90°	0° (Horizontal)	90° (Vertical)
Pressure	98 – 196 kPa	140 – 377 kPa	75 – 133 kPa	207 kPa	114 – 146 kPa	102 – 186 kPa	208 – 401 kPa
Temperature	10 – 26.5 C	29 – 41 C	13 – 20 C	N/A (23 C assumed)	21 – 38 C	21 – 50 C	3 – 25 C
Gas Sup. Velocity	0.8 – 163 m/s	0.87 – 9.4 m/s	3.6 – 12.7 m/s	5 – 25 m/s	36 – 82 m/s	0.09 – 7.7 m/s	0.03 – 22.53 m/s
Liquid Sup. Velocity	0.001 – 0.34 m/s	0.88 – 2.02 m/s	0.03 – 0.05 m/s	0.00025 – 0.03 m/s	0.0034 – 0.04 m/s	0.01 – 3 m/s	0.003 – 2.39 m/s
Liquid Density	1000 kg/m3	796 – 804 kg/ m3	810 – 815 kg/ m3	1000 kg/m3	1000 kg/m3	856 – 870 kg/ m3	810 – 829 kg/ m3
Liquid Viscosity	1 cP	0.0012 – 0.0015 cP	0.0016 – 0.0019 cP	1 cP	1 cP	0.04 – 0.17 cP	0.0016 – 0.0027 cP

Table 2: Conditions of the experiments investigated in this study

As members of TUFFP, AspenTech has access to papers, software and experimental data. TUFFP provides a categorized database of approximately 40 experimental datasets, which can be divided by authors, number of phases, and types of fluids. Most of the data is for two-phase systems of air-water, air-oil (mainly lubricants), and air-kerosene, but there is some data on three-phase systems. **Table 2** lists the seven experimental datasets used in this study. These were selected because they cover a range of conditions and fluids and had complete data. Unfortunately, data from a three-phase system could not be included in this investigation due to missing data.

Pipe Flow Simulations: Aspen HYSYS

In this study, the pipe segment unit operation in Aspen HYSYS was used to model the experiments presented in **Table 2**. (Alternatively, the pipe operation in the Aspen Hydraulics sub-flowsheet could also be used.) With the pipe model, several of the correlations in Table 1 can be used to calculate the flow regime, liquid hold-up and pressure gradient, which can then be compared to the experimental values.

A program was developed in Microsoft Excel that reads the input parameters such as pressure, temperature, mass flow and pipe dimensions from the TUFFP database and passes the values into Aspen HYSYS through the automation interface. The composition of air, water and kerosene were taken from the HYSYS Pure Component Databank. The Peng-Robinson or Braun K thermodynamics models were used for the fluid properties. In addition, the flow line is assumed to be plastic tubing because the test flow loop was made by acrylic material. The overall parameters for the Aspen HYSYS simulation are shown in **Table 3**. There were no fitting or tuning parameters adjusted for any of the correlations, so the simulation results can be considered predictive.

In the case of the air-oil experiments performed by Brito in 2012, the HYSYS Oil Manager was used to characterize the fluid with the known viscosity, density and average molecular weight. The properties of oil are listed in **Table 4**, including the temperatures and viscosities of two points from the curvature graph provided by the author.

Component Property	HYSYS Pure Component Databank
Fluid Property	Peng-Robinson or Braun K
Pipe Material	Plastic Tubing
Pipe Roughness	1.4e-05 m
Pipe Roughness	0.17 W / m / K

Table 2: Conditions for calculation in HYSYS

Molecular Weight	320
Standard Density	888 kg/m3
Temperature (1)	5 C
Viscosity (1)	397 cP
Temperature (2)	74 C
Viscosity (2)	16 cP

Table 3: : Oil properties used in Aspen HYSYS to create the fluid model for the Brito (2012) experimental studies

Once the simulation data is obtained, the effectiveness of each correlation can be quantified using the fraction of variance unexplained (FVU), which is given by:

$$FVU = \frac{\sum[x(n) - \hat{x}(n)]^2}{\sum[x(n) - \bar{x}]^2}$$

where x(n) is the experimental observation, $\hat{x}(n)$ is the predicted value from the correlation, and $\bar{x}$ is the mean of the experimental observations. An FVU of zero indicates a perfect prediction.

Pipes with Horizontal Geometry

Horizontal flow is the most common pipeline geometry in practice and as a result also comprises most of the experiments in the TUFFP database. The data investigated in this study includes 596 experimental pressure gradient and liquid hold-up measurements from Andritsos (1986), Yang (1996), Brill (1995), Fan (2005), Magrini (2009) and Brito (2012). Most of the experiments were for the two-phase flow of air and water, but air-kerosene and air-oil systems were also investigated. **Table 2** summarizes the conditions of these experiments.

Figure 3 compares the pressure gradient measured in the experiments with those calculated from four correlations (Tulsa Unified Model, Beggs and Brill [1979], Gregory et al. and HTFS) used in the Aspen HYSYS pipe segment. As previously mentioned, there were no fitting or tuning parameters adjusted in the models for the calculations. Qualitatively, the Tulsa Unified, Gregory and HTFS models capture the experimental pressure gradients well, while the Beggs and Brill model does not appear to be a good predictor for the pressure gradient. At lower pressure gradients, the Tulsa Unified Model has a slight tendency to under-predict the pressure gradient, while the Gregory and HTFS models tend to over-predict the pressure gradient in this region. Conversely, the Beggs and Brill (1979) correlation consistently over-predicts the pressure gradient.

The comparison between the experimental and predicted liquid hold-up values is shown in **Figure 4**. It should be noted that data from Yang (1996) is not shown in these plots because the liquid hold-up values were not reported, which is likely because the flow regime was slug flow. As shown in **Figure 4(a)**, the Tulsa Unified Model predicts the liquid hold-up reasonably well except at very low hold-up values. However, all the models fail to predict accurately the low hold-up values reported by Andritos, which could indicate an issue with the experimental measurements in this region.

Pipes with Horizontal Geometry

While the HTFS and Gregory models predict the pressure gradient well, as shown in **Figures 3(c) and 3(d),** they do not accurately determine the liquid hold-up for this set of experiments. This discrepancy in predictions is possible in horizontal flow, as the liquid hold-up will affect the overall fluid density, which has a larger impact on the gravitational pressure gradient than on the frictional pressure gradient.

Table 5 gives the FVU for both the pressure gradient and liquid hold-up predictions for each model in this horizontal geometry. In addition, the table also reports the fraction of times that the flow regime was predicted successfully by the correlation. It should be noted that the experiments by Andritsos did not report a flow regime, so this data is not included in the flow regime prediction results. Additionally, the HTFS model does not report the flow regime. As was qualitatively concluded from the plots in **Figs. 3 and 4**, the Tulsa Unified, Gregory et al., and HTFS models all do well to predict the pressure gradient, while the Beggs and Brill model does not perform well for the examined experiments. The lack of success of the Beggs and Brill model could be due to the poor flow regime prediction, which influences significantly the pressure and hold-up calculations. Additionally, the FVU for the liquid hold-up shows that the HTFS and Gregory models are not as accurate as the other models, which is consistent with **Figure 4**.

Correlation	FVU in Pressure Gradient	FVU in Liquid Hold-Up	Flow Regime Prediction
Tulsa Unified Model	0.047	0.112	0.86
Beggs & Brill (1979)	4.728	0.226	0.41
Gregory et al.	0.076	0.474	0.93
HTFS	0.034	0.388	N/A

Table 5: Performance of predicting the pressure gradient, liquid hold-up and flow regime using different correlations in a horizontal geometry

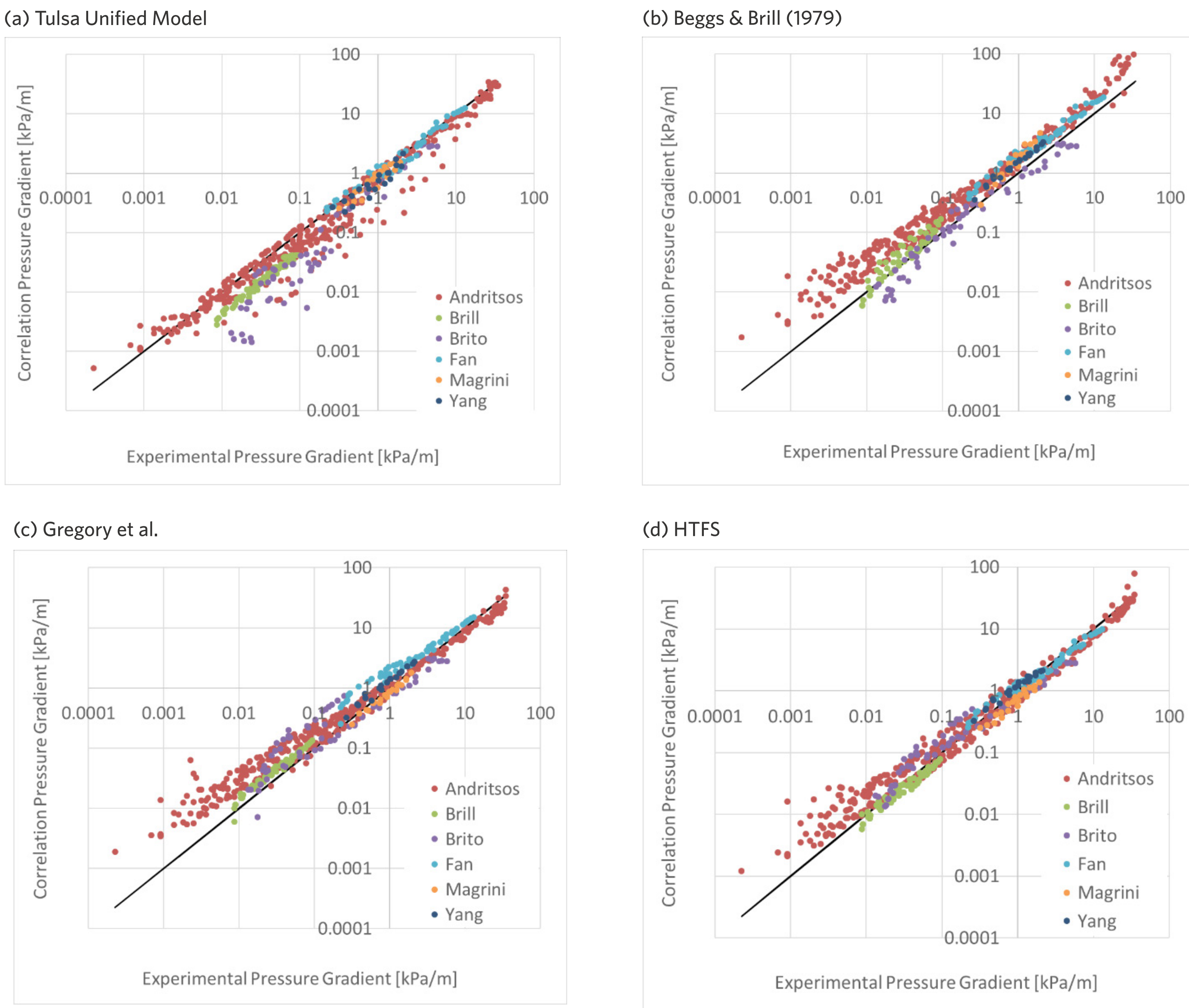

Figure 3: Comparison of the pressure gradient between calculated and experimental results in a horizontal geometry

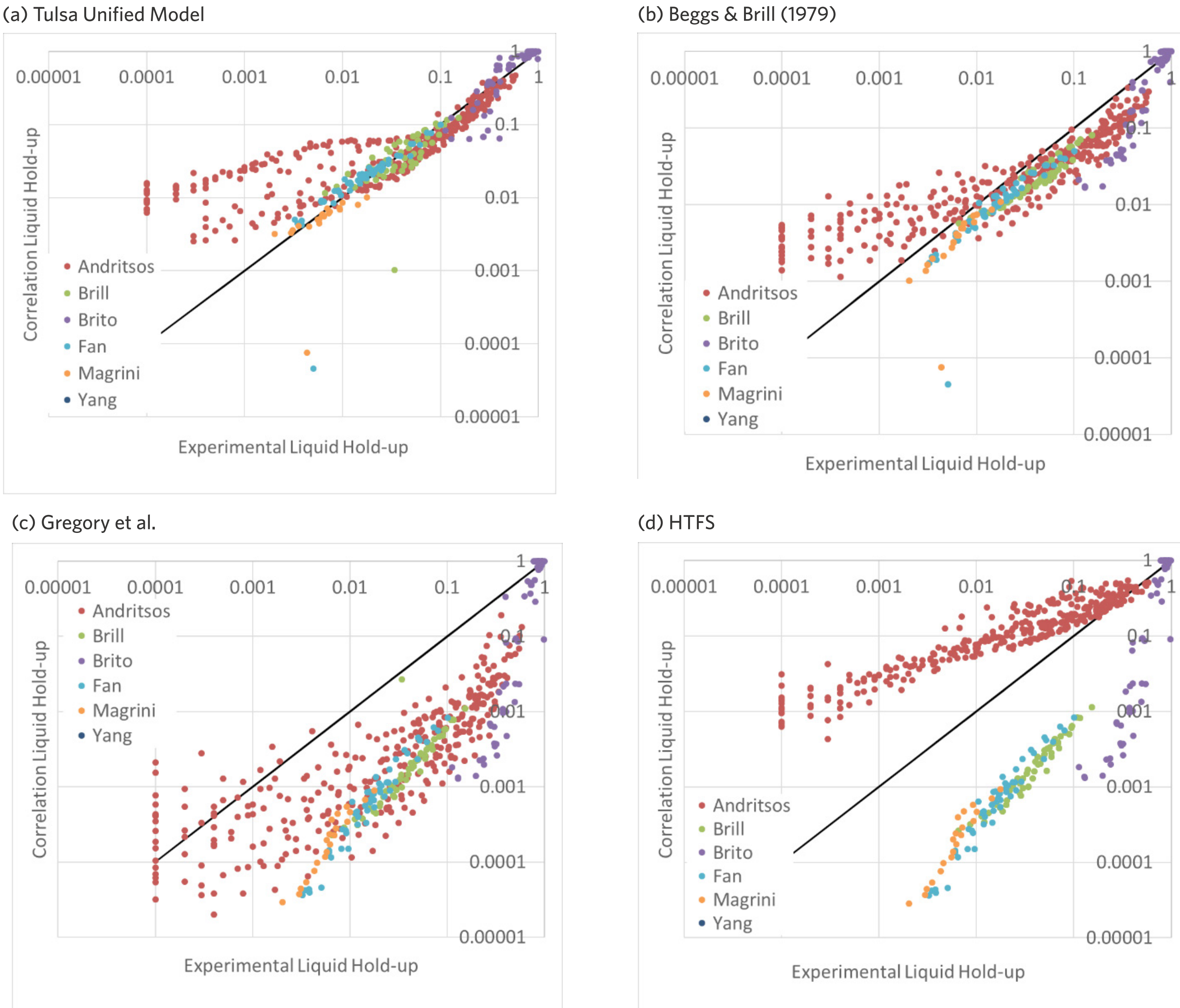

Figure 4: Comparison of the liquid hold-up between calculated and experimental results in a horizontal geometry

Pipes With Inclined Geometry

The experiments of Magrini and Fan listed in **Table 2** not only investigated horizontal flow but also upward and downward inclined flows. Comparison of the correlation predictions of pressure gradient and liquid hold-up with the 216 experimental points in an inclined geometry are shown in **Figures 5 and 6**. Additionally, **Table 6** gives the FVU for both the pressure gradient and liquid hold-up predictions as well as the accuracy of the flow regime predictions.

As these figures and table show, the results for the inclined flows show similar trends with the results in horizontal geometry. The Tulsa Unified model does well to predict both the pressure gradient and liquid hold-up. Again, the Beggs and Brill (1979) correlation consistently over-predicts the pressure gradient but under-predicts the liquid hold-up. Finally, both the Gregory and HTFS models accurately capture the pressure gradient but significantly under-predict the hold-up. Again, like the horizontal flow comparisons, the poor prediction of the liquid hold-up from these models does not significantly impact the pressure gradient calculation. This is due to the low liquid hold-up values, which means that there will not be a significant contribution to the pressure gradient from gravitational effects.

Correlation	FVU in Pressure Gradient	FVU in Liquid Hold-Up	Flow Regime Prediction
Tulsa Unified Model	0.039	0.525	0.98
Beggs & Brill (1979)	3.243	0.937	0.45
Gregory et al.	0.044	3.661	0.73
HTFS	0.095	3.667	N/A

Table 6: Performance of predicting the pressure gradient, liquid hold-up and flow regime using different correlations in an inclined geometry

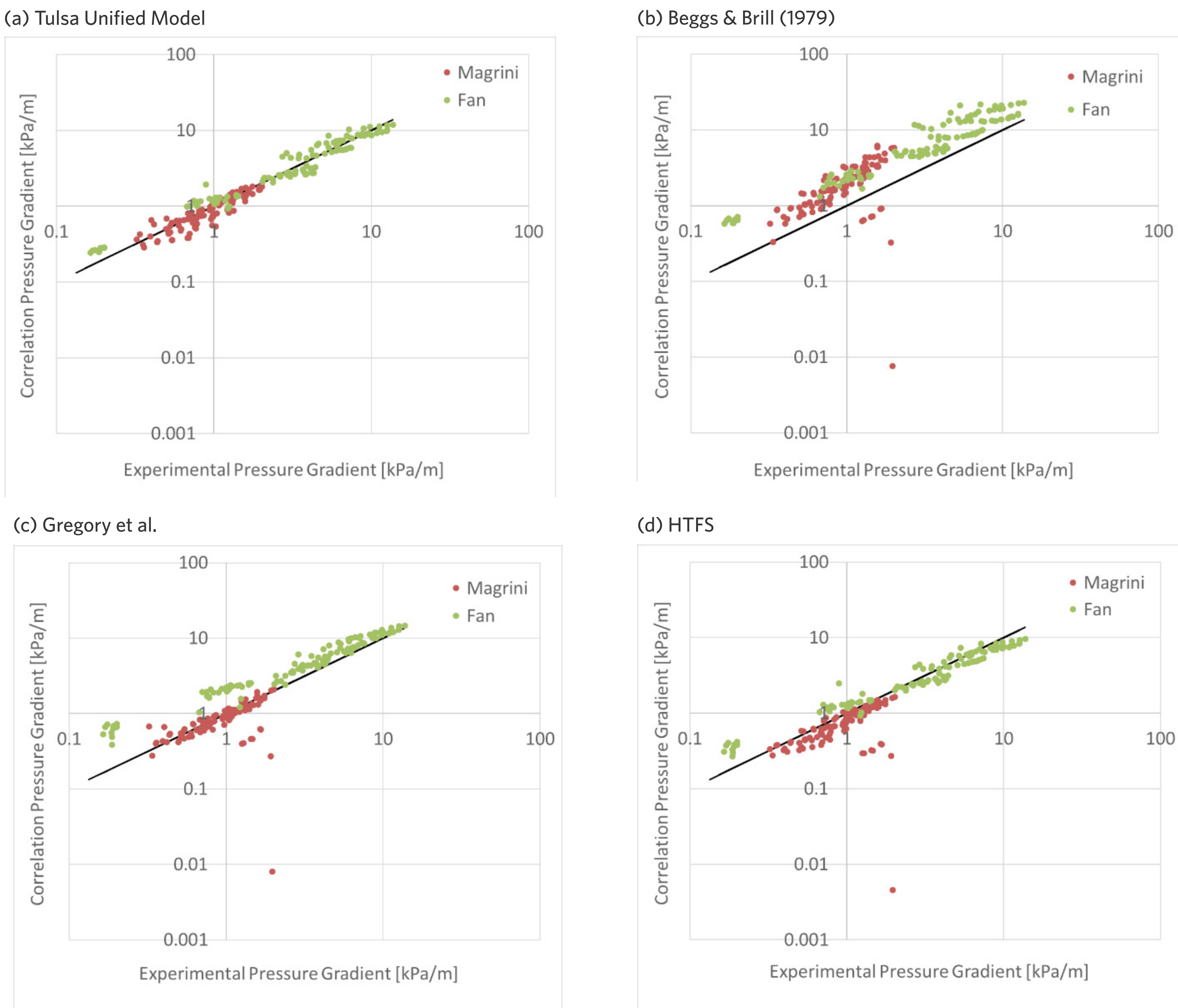

Figure 5: Comparison of the pressure gradient between the calculated and experimental results in an inclined geometry

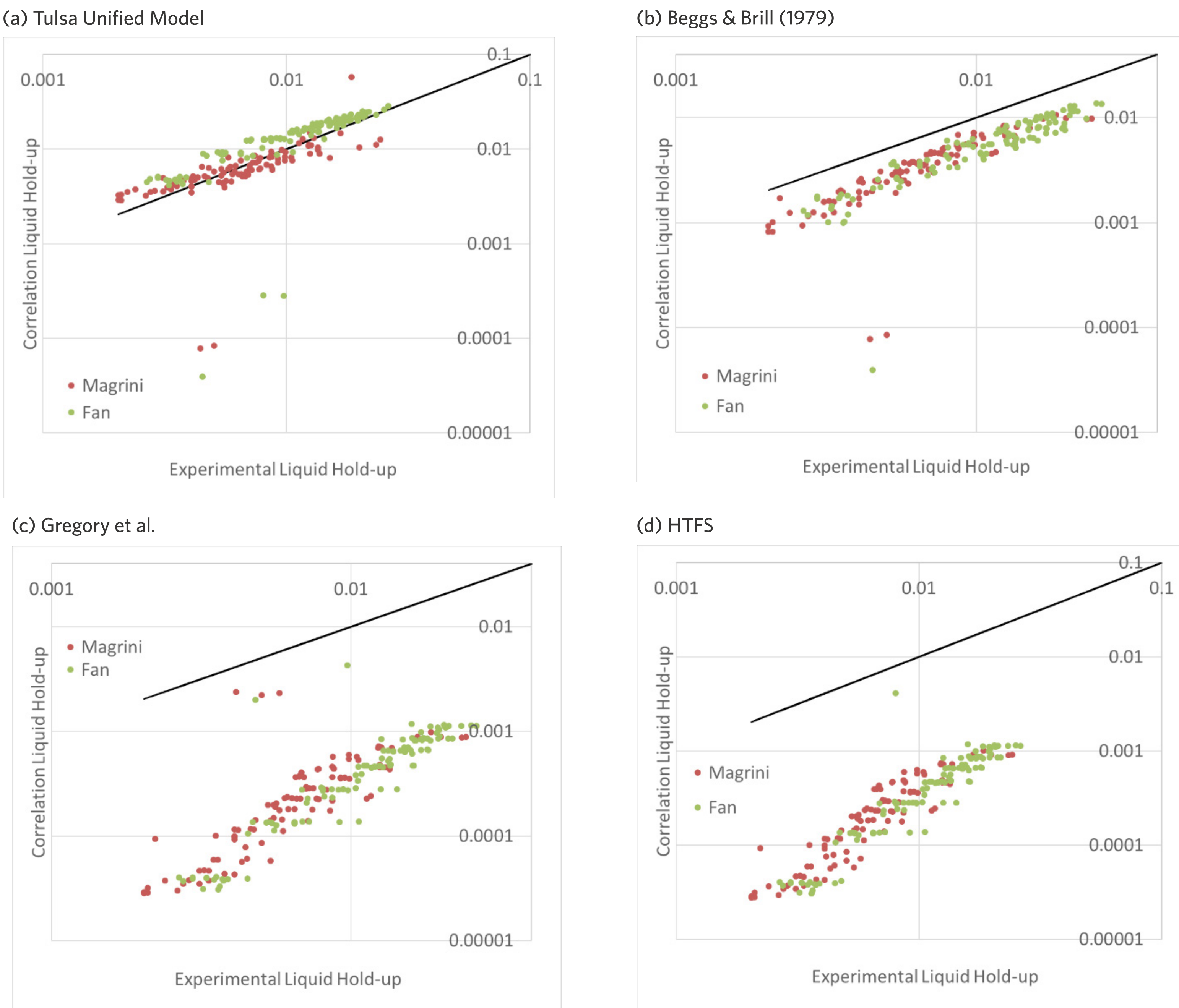

Figure 6: Comparison of the liquid hold-up between the calculated and experimental results in an inclined geometry

Pipes with Vertical Geometry

Vertical flow was investigated by Magrini and Caetano. In this geometry, the Aziz et al. and Duns and Ros models, which are only applicable to vertical flow, were investigated in addition to the Tulsa Unified, Beggs and Brill (1979), and HTFS models. Both of these models are empirical and will actually give the same results in mist and transition flow regimes. **Figures 7 and 8** compare the pressure gradient and liquid hold-up for the experiments and simulations. **Table 7** also gives the FVU for both the pressure gradient and liquid hold-up predictions for each model, as well as a measure of the accuracy of the flow regime prediction.

In multiphase vertical flow, an accurate prediction for the liquid hold-up is necessary to determine the pressure gradient because the gravitational pressure gradient will be a significant contributor to the overall pressure gradient. Therefore, as seen in **Table 7**, there is a stronger correlation between the FVU for the liquid hold-up and the FVU for the pressure gradient.

For the data investigated, the Aziz et al. model most accurately captures the flow regime, liquid hold-up, and pressure gradient. Although this model is empirical, it was developed with data from the flow of gas and condensate in vertical wells, which appears to capture the conditions of the investigated experiments.

The Tulsa Unified, Duns and Ros, and HTFS models perform well in predicting the pressure gradient and liquid hold-up. The Beggs and Brill model does not capture the Magrini data points well and tends to under-predict the pressure gradient, contrary to its behavior in the horizontal and inclined flow geometries.

Correlation	FVU in Pressure Gradient	FVU in Liquid Hold-Up	Flow Regime Prediction
Tulsa Unified Model	0.212	0.080	0.87
Beggs & Brill (1979)	0.235	0.244	0.60
Aziz et al.	0.044	0.057	0.88
Duns & Ros	0.165	0.060	0.81
HTFS	0.169	0.139	N/A

Table 7: Performance of predicting the pressure gradient, liquid hold-up and flow regime using different correlations in a vertical geometry

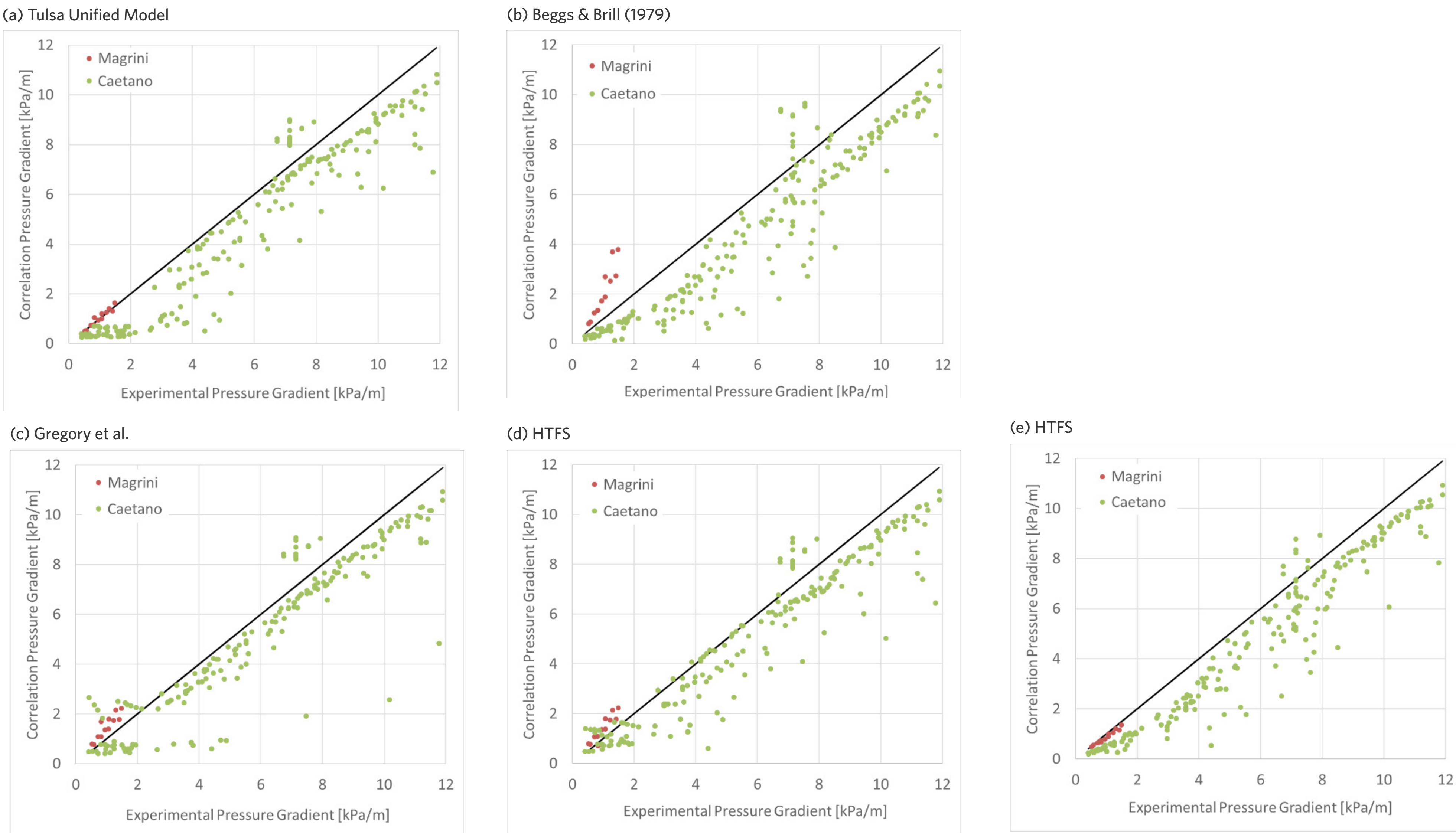

Figure 7: Comparison of the pressure gradient between the calculated and experimental results in a vertical geometry

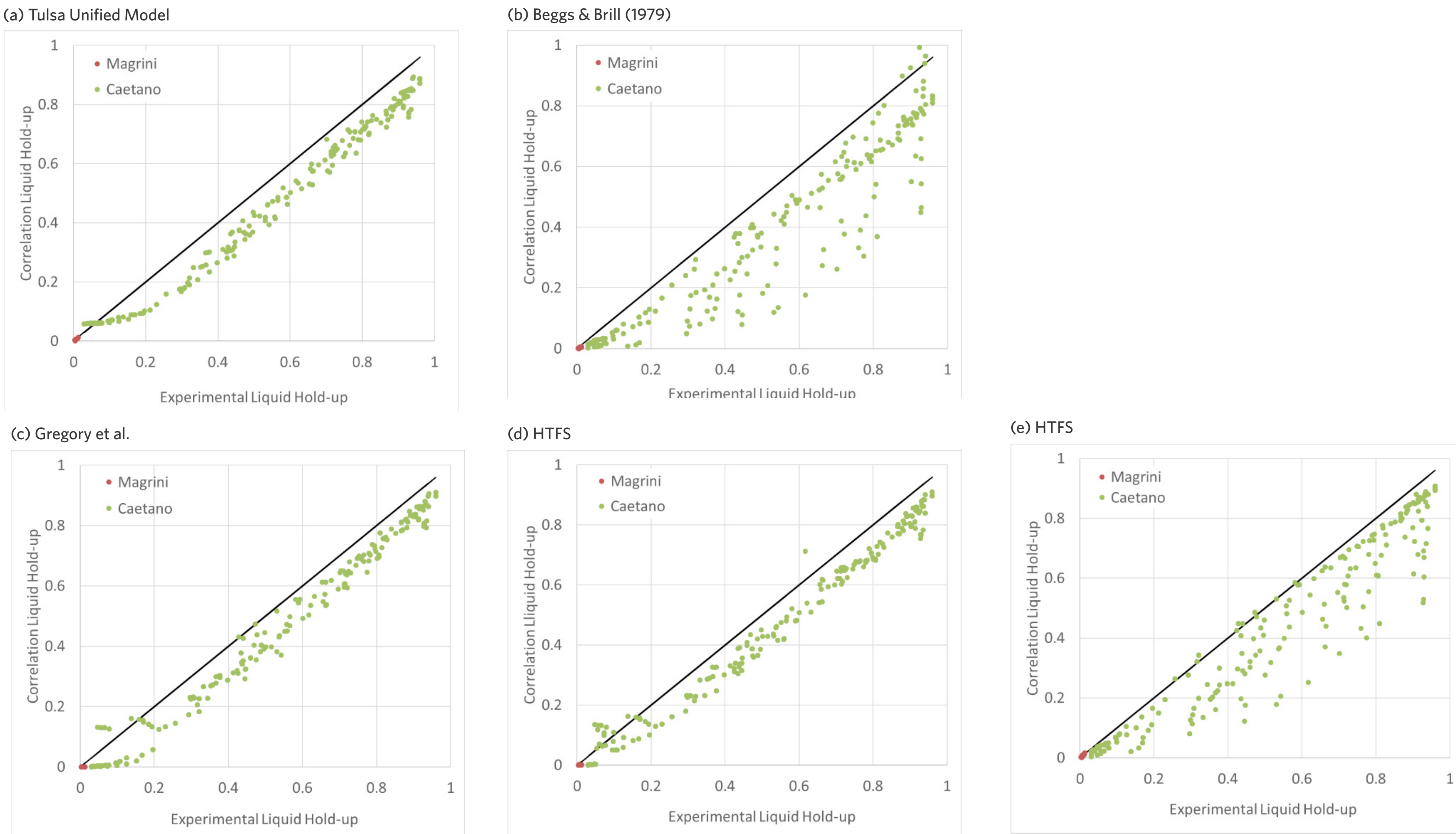

Figure 8: Comparison of the liquid hold-up between the calculated and experimental results in a vertical geometry

Conclusions

In this study, pipe flow simulations in Aspen HYSYS were compared to experiments performed through the Tulsa University Fluid Flow Project. The predictions of several flow correlations for the flow regime, liquid hold-up and pressure gradient were compared to the experimental values for different geometries, fluids and conditions. While there were over 1,100 experimental data points examined, the comparisons are still on a limited range of conditions that are typical for pipelines, and the flowing fluids were not actual hydrocarbon fluids typically found in oil and gas applications. Therefore, one still must be judicious when applying correlations to a particular system.

In the horizontal flow systems examined, the Tulsa Unified, HTFS, and Gregory et al. models prediction for the pressure gradient agreed well with the experimental measurements. The Tulsa Unified model, however, gave much better predictions for the liquid hold-up, except at low hold-up values. The HTFS and Gregory et al. models do not give very accurate predictions for the liquid hold-up. For this geometry, the Beggs and Brill (1979) model tends to over-predict the pressure gradient but gives reasonable results for the liquid hold-up.

The results for an inclined geometry were consistent with those of the horizontal geometry. Specifically, the Tulsa Unified model performed well in predicting the pressure gradient, liquid hold-up, and flow regime. The HTFS and Gregory et al. models predict the pressure gradient but not the liquid hold-up. Like the horizontal geometry, the Beggs and Brill (1979) model tends to over-predict the pressure gradient but gives reasonable results for the liquid hold-up.

In vertical flow experiments investigated, the empirical Aziz et al. model most accurately captures the flow regime, liquid hold-up, and pressure gradient. The Tulsa Unified, Duns and Ros, and HTFS models perform fairly well in predicting the pressure gradient and liquid hold-up. Unlike the horizontal and inclined geometry cases, the Beggs and Brill model tends to under-predict the pressure gradient in this vertical geometry.

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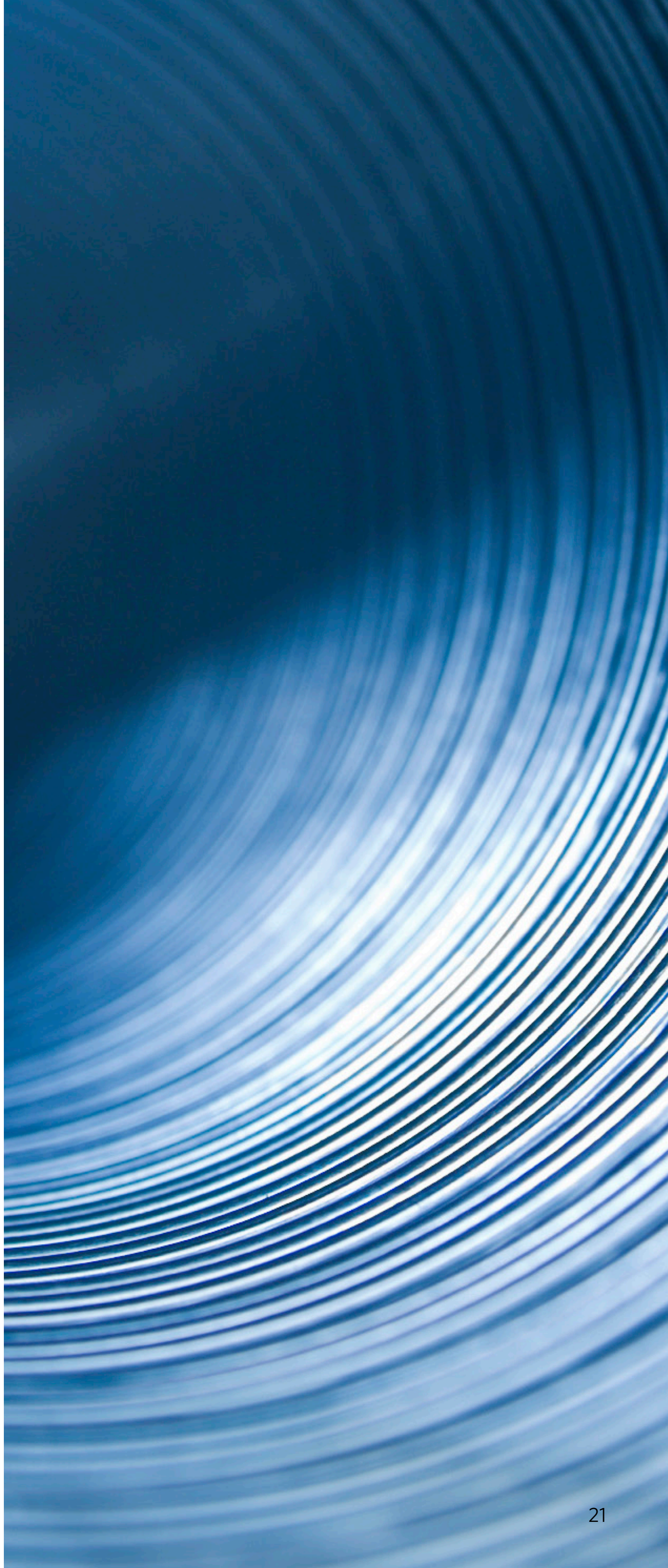

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