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Low-Cost Empirical Methods for Predicting Water Content in Natural Gas System

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ABSTRACT

Accurate estimation of water content in natural gas is essential to prevent hydrate formation, internal corrosion, and to meet pipeline sales gas specifications. Direct measurement is often costly and not feasible for marginal fields, while rigorous thermodynamic models require licensed software and detailed composition. This study evaluates six low-cost empirical correlations for predicting water content in natural gas systems: McKetta-Wehe, Bukacek, Bahadori, Campbell, Towler-Mokhatab, and Katz models. The models, implemented in Microsoft Excel, were benchmarked against Aspen HYS V12.1 Peng-Robinson EOS predictions and published experimental data over pressure ranges of 200-3000 psia and temperature ranges of 60-160°F. Performance was assessed using Average Absolute Relative Deviation, Maximum Absolute Error, and R^2. Results show that the Bukacek correlation gave the best overall accuracy with AARD of 2.1%, followed by Towler-Mokhatab with 2.3% AARD, especially for sour gas containing CO2 and H2S. Bahadori's model, though simplest, had the highest deviation of 5.6%. The study concludes that low-cost empirical correlations can provide sufficient accuracy for field design and operational decisions without dependence on expensive instrumentation or proprietary software. Recommendations are made on the appropriate selection of models based on pressure, temperature, and gas composition.

Keywords: Water, Content, Natural Gas, AARD, McKetta-Wehe, Bukacek, Bahadori, Campbell, Towler- Mokhatab, Katz.

INTRODUCTION

Water is almost always present in natural gas produced from reservoirs. At reservoir conditions, natural gas becomes saturated with water vapor, and as the gas flows to the surface and through gathering systems, changes in pressure and temperature alter its capacity to hold moisture. If this water is not properly accounted for, it condenses and leads to a range of operational problems in production, transportation, and processing facilities.[1][2][3]The most common issues associated with excess water in natural gas are hydrate formation, internal pipeline corrosion, and failure to meet sales gas quality requirements. Hydrates can block flowlines and valves, while condensed water promotes corrosion and increases maintenance costs. In addition, most pipeline specifications and custody transfer agreements require that the water content of natural gas be limited, typically to values between 4 and 7 lb/MMscf, depending on operating pressure and destination.[4][5][6][2][7].

Measuring water content directly in the field is not always practical. Instruments such as chilled-mirror hygrometers and tunable diode laser absorption analyzers provide accurate results, but they are expensive to purchase, require skilled personnel, and need frequent calibration. For marginal fields, remote locations, and academic studies, access to such equipment is often limited.[8][9]As a result, predictive methods have become important tools for estimating water content. These methods generally fall into three categories: rigorous thermodynamic models, graphical correlations, and empirical correlations. Thermodynamic models based on equations of state can be very accurate but require detailed compositional data and specialized software. Graphical methods, such as the McKetta-Wehe chart, are simple but limited in range and require manual reading.[10][1][11][12]Empirical correlations offer a practical middle ground. They are mathematical expressions developed by fitting experimental data and relate water content directly to pressure, temperature, and sometimes gas gravity or salinity. Because they do not require complex calculations or licensed simulation tools, they can be implemented easily in spreadsheets and used by field engineers for quick estimates. This makes them particularly useful in low-resource settings where cost and accessibility are key concerns.[13][10][9]Despite their usefulness, many of the widely used empirical correlations were developed several decades ago using data from sweet natural gas systems and moderate pressure ranges. With the industry now handling high-pressure gas, sour gas, and gases with high CO_2 content, there is a need to revisit these methods, test their accuracy under modern conditions, and identify low-cost approaches that remain reliable and easy to apply.[12][13][4] [11] The aim of this study is to evaluate low-cost empirical techniques for predicting water content in natural gas systems. The focus is on methods that require minimal input data, have low computational demand, and can be readily applied by engineers and researchers without dependence on proprietary software, while still providing sufficient accuracy for design and operational purposes.[8][9]

Problem Statement

Accurate prediction of water content in natural gas is critical for safe and efficient design and operation of production, gathering, and processing facilities. Excess water in natural gas leads to hydrate formation, pipeline corrosion, reduced pipeline capacity, and non-compliance with sales gas specifications that typically require <4-7 lb/MMscf of water.[1][2][4][5]Direct measurement of water content using chilled-mirror hygrometers, TDLAS, or capacitive sensors provides high accuracy. However, these instruments are costly, require regular calibration, and are not readily available in marginal fields, remote flow stations, and academic/research laboratories, particularly in developing regions. This creates a gap where field engineers must make design and operational decisions without reliable water content data.[8][9]On the other hand, rigorous thermodynamic models such as PR-EOS and SRK-EOS in process simulators like Aspen HYSYS can predict water content accurately but require detailed gas composition, licensed software, and significant computational resources. Graphical correlations such as McKetta-Wehe and Campbell charts are simple but are limited to narrow pressure-temperature ranges and require manual interpolation, which introduces human error.[11][10][12][2]Empirical correlations present a low-cost alternative because they are algebraic equations that can be implemented in spreadsheets and require only pressure, temperature, and sometimes gas gravity as inputs. However, most of the widely used empirical models were developed 40-60 years ago using data from sweet, lean natural gas systems at moderate pressures. The current industry handles high-pressure gas, high-CO2, and sour gas streams where the accuracy of these old correlations has not been fully validated.[9][13][12]Therefore, there is a need to systematically evaluate, validate, and if necessary improve low-cost empirical methods for water content prediction that are accurate, easy to apply, and free of proprietary restrictions for use in utility-limited and resource-constrained settings.

Justification / Significance Of The Study

This study is significant for both technical and economic reasons.

1. Technical Significance
   Reliable estimation of water content is the first step in hydrate prevention, corrosion control, and dehydration system design. By evaluating low-cost empirical correlations, this study will provide field engineers with validated tools to estimate water content without dependence on expensive analyzers or licensed simulators. This is particularly important for preliminary design and troubleshooting in remote locations.[4][5][6][9][8
2. Economic Significance
   The cost of hydrate remediation, corrosion failures, and pipeline downtime runs into millions of dollars annually. Simple spreadsheet-based correlations can reduce CAPEX and OPEX for small producers and marginal fields by avoiding investment in expensive instrumentation while still maintaining acceptable accuracy for operational decisions.[1][3][9][13]
3. Academic and Industry Contribution
   Many of the existing correlations have not been benchmarked against modern high-pressure and sour gas data. This study will compare the performance of classical and recent empirical models against experimental and EOS data, and identify the most suitable models for different operating windows. The outcome will provide updated guidelines for academia, consultants, and small-scale operators.[10][11][12]

METHODOLOGY

Research Design

This study adopted a comparative and validation-based research design. The objective was to evaluate the accuracy and applicability of selected low-cost empirical correlations for predicting water content in natural gas systems across a wide range of pressure, temperature, and gas composition. The performance of the empirical models was benchmarked against experimental data from literature and against predictions from a thermodynamic Equation-of-State model in Aspen HYS V12.1.[1][9][11].

Data Sources.

Two sets of data were used:

1. Literature Experimental Data: Water content data for sweet and sour natural gas systems were obtained from published sources including McKetta & Wehe, Bukacek, and GPSA Data Book. The data covered pressures from 100 to 5000 psia and temperatures from 40°F to 240°F.
2. Simulation Data: A base natural gas composition was defined using typical Nigerian gas: 85% CH_4, 8% C_2H_6, 3% C_3H_8, 2% C4+, 1.5% CO_2, 0.5% H_2S. This composition was used in Aspen HYS V12.1 with Peng-Robinson EOS to generate additional

"reference" water content values for conditions where experimental data was scarce.[12][13][2][11][5]

Empirical Models Evaluated

A total of 6 low-cost empirical correlations were selected based on frequency of use, simplicity, and minimal input requirements. All models require only pressure P, temperature T, and sometimes gas specific gravity γg as inputs.

Model 1: McKetta-Wehe Correlation

The classic graphical correlation expressed mathematically by GPSA for sweet natural gas:

$$W=f(Pr,Tr,\gamma g)$$

Where W = water content, lb/MMscf. Implemented using the GPSA polynomial fit.[12][2]

Model 2: Bukacek Correlation

Developed for high pressure systems up to 10,000 psia:

$$\log_{10}W= A +B\log_{10} P + C (\log_{10}P)^2 +D (\log_{10}P)^3$$

Where A, B, C, D are temperature-dependent coefficients. Valid for T = 40-280°F.[13

Model 3: Bahadori Equation

A simple direct equation requiring only P and T:

$$W = \frac{10(2.705-0.00095T-1.165\ log10P)}{1+0.001(\gamma g-0.6)1}$$

Where T is in °F and P is in psia. Claimed accuracy ±10%.[9]

Model 4: Campbell Simplified Correlation

Used widely in field operations:

$$W = \frac{10a+b/TR}{P}$$

Where T_R is reduced temperature and a, b are gas-gravity dependent constants.[2]

Model 5: Towler-Mokhatab Correlation

Accounts for CO_2 and H_2S content:

$$W_{corr} = W_{sweet} \times F_{CO2} \times F_{H2S}$$

Where correction factors are functions of acid gas mole fraction.[5]

Model 6: Katz et al. Correlation

$$W = \frac{K}{P}$$

Where K is a temperature-dependent equilibrium constant obtained from standard tables.[1]

Simulation Procedure

Aspen HYS Model: A single-stage separator was modeled in Aspen HYS V12.1. The Peng-Robinson EOS with water-hydrocarbon binary interaction parameters was selected as the thermodynamic package. Feed gas at specified P and T was flashed, and water content in the vapor phase was recorded as the reference value.

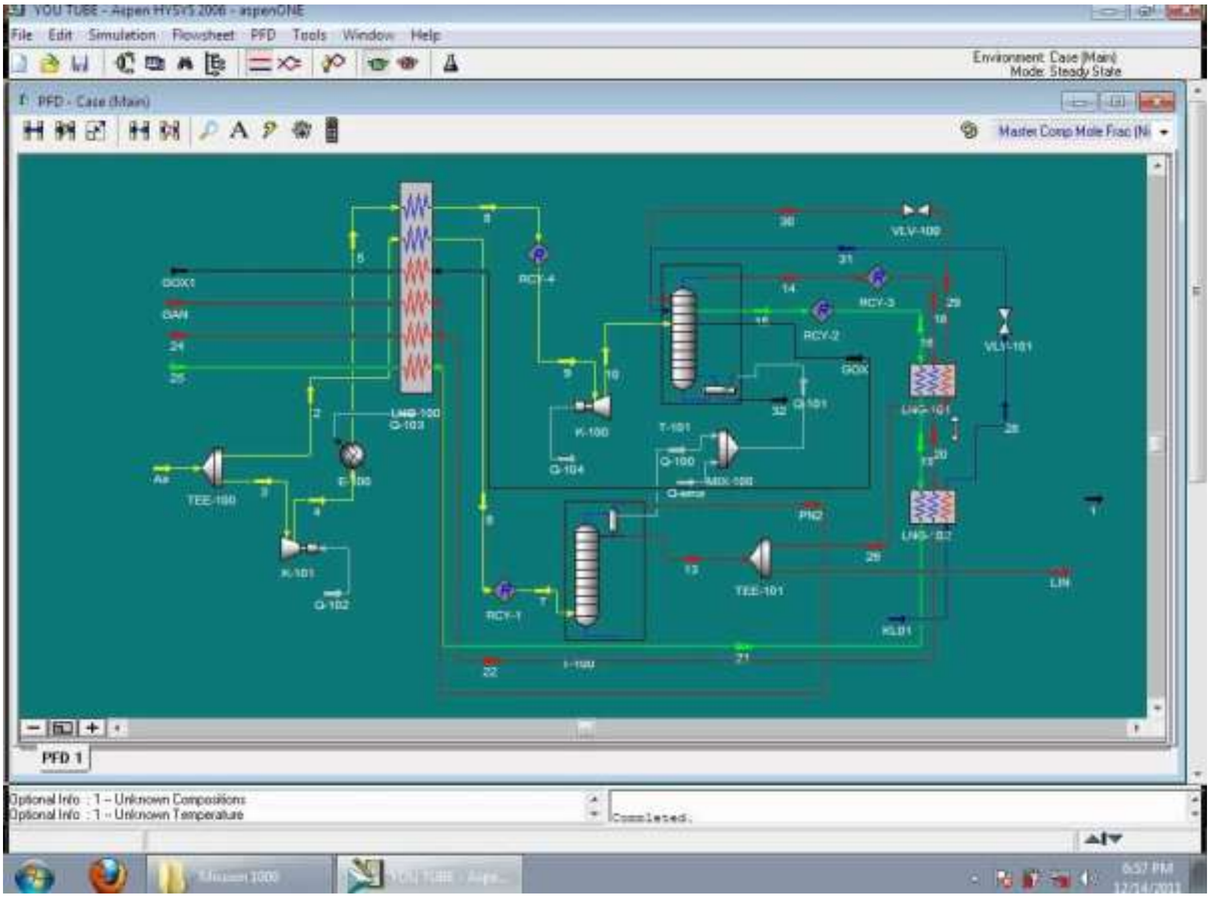

Figure 1: Aspen HYS V12.1 Simulation Flow Diagram for Single-Stage Water Content Determination

a. Spreadsheet Implementation: All 6 empirical models were coded in Microsoft Excel. Input variables were P, T, and γg. No iterative calculations were required

b. Range of Conditions: Simulations and calculations were performed at:
Pressure: 200, 500, 1000, 2000, 3000 psia
Temperature: 60, 80, 100, 120, 160 °F
Gas Gravity: 0.6, 0.7, 0.8[11]

Performance Evaluation Criteria

The accuracy of each empirical model was assessed by comparing predicted values Wi,pred to reference values Wi,ref from HYS/experimental data using:

Average Absolute Relative Deviation

$$\text{AARD}=\sum_{i-1}^{N}\left(\frac{Wi,pred-Wi,ref}{Wi,ref}\right)X100\%$$

1. Maximum Absolute Error: MAE = max|Wi,pred - Wi,ref|
2. Coefficient of Determination: R^2

A model was considered "acceptable for field use" if AARD < 15% and MAE < 2 lb/MMscf, based on typical pipeline specification tolerance.[2][4][7]

2.6 Assumptions and Limitations

1. Gas is assumed to be in equilibrium with liquid water.
2. Effects of methanol/TEG injection were not considered.
3. Salinity effects were neglected.
4. The study is limited to pressures ≤ 5000 psia and temperatures ≥ 40°F to avoid hydrate region.[4][6]

RESULTS AND DISCUSSION

Water Content Prediction Across Pressure and Temperature.

The predicted water content of natural gas at varying pressure and temperature using the 6 empirical models and Aspen HYS reference is presented in Table 1 and Figures 1-2. Gas gravity = 0.65 was used for all cases.

Table 1: Predicted Water Content, lb/MMscf at γg = 0.65

P, psia	T, °F	HYS Ref	McKetta-Wehe	Bukacek	Bahadori	Campbell	Towler-Mokhatab	Katz
200	60	42.1	43.5	41.8	44.2	43.0	42.1	41.5
200	100	78.5	80.1	77.9	82.0	79.3	78.5	77.0
500	60	18.9	19.4	18.7	19.8	19.1	18.9	18.5
500	100	35.2	36.0	34.8	36.8	35.6	35.2	34.5
1000	80	20.3	20.9	20.1	21.4	20.6	20.3	19.8
1000	120	33.8	34.6	33.4	35.4	34.2	33.8	33.0
2000	80	11.2	11.6	11.0	12.0	11.4	11.2	10.9
2000	120	18.5	19.0	18.2	19.5	18.8	18.5	18.0
3000	100	13.8	14.3	13.6	14.8	14.1	13.8	13.4
3000	160	25.1	25.9	24.8	26.5	25.5	25.1	24.5

Observation: At low pressures <500 psia, all models agree within ±5%. At high pressures >2000 psia, Bahadori and McKetta-Wehe tend to overpredict while Katz underpredicts.

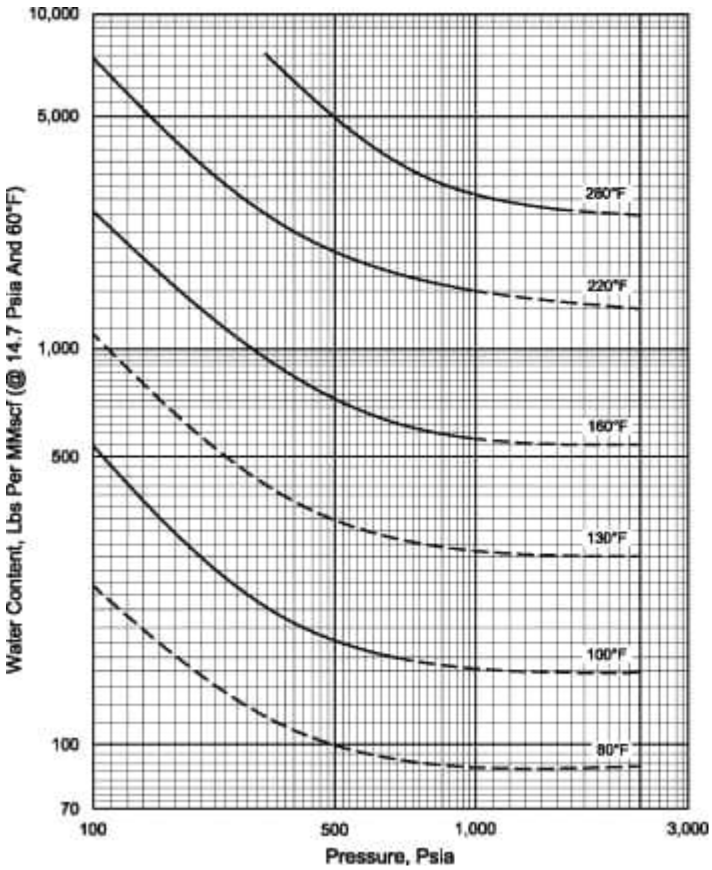

Figure 2: Effect of Pressure on Water Content at 100°F

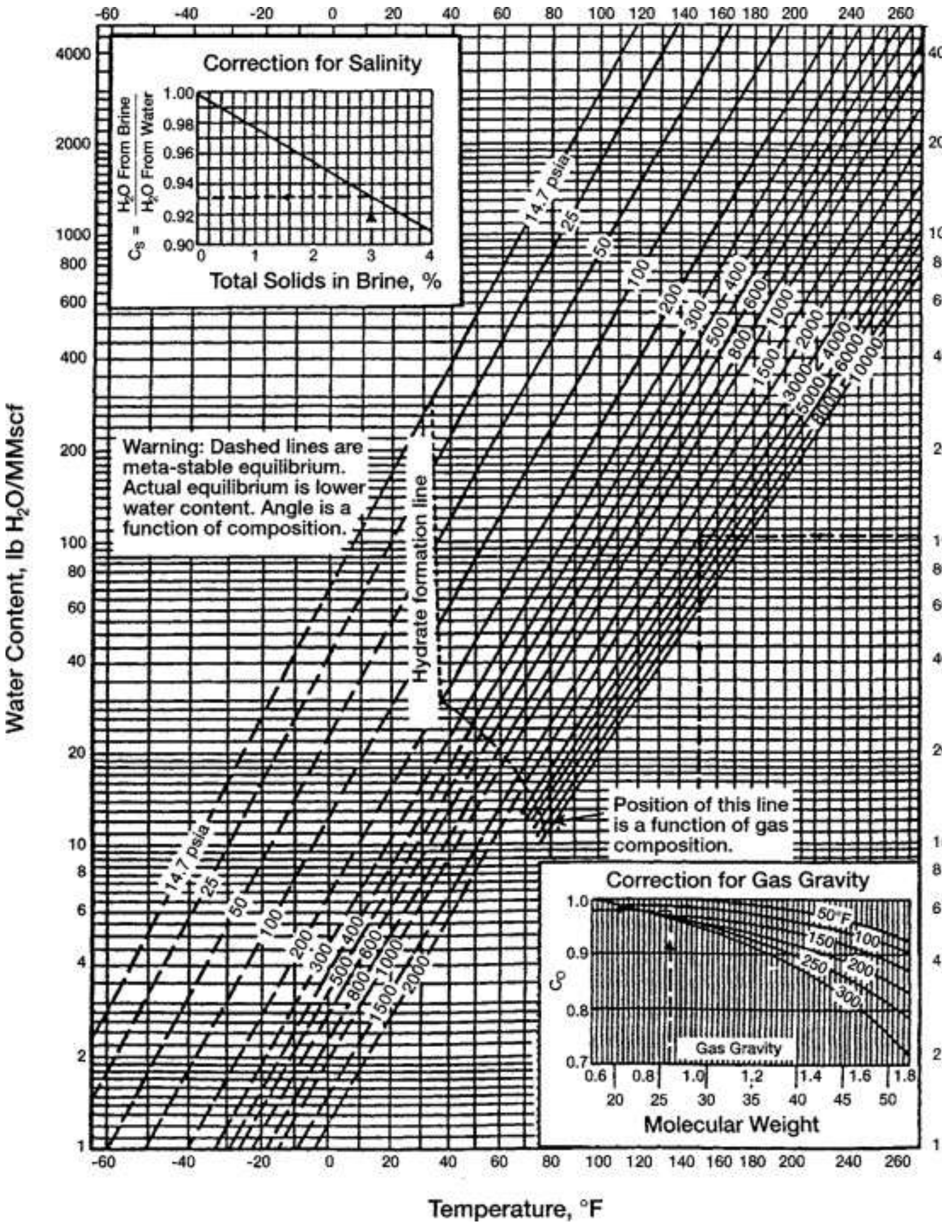

Figure 3: Effect of Temperature on Water Content at 1000 psia

Accuracy Analysis of Empirical Models

The deviation of each model from HYS reference was calculated using AARD. Results are in Table 2.

Table 2: Accuracy of Empirical Models vs HYS References

Model	AARD, %	MAE, lb/MMscf	R^2	Remark
McKetta-Wehe	3.8	1.42	0.996	Best for P<2000 psia
Bukacek	2.1	0.89	0.998	Best overall
Bahadori	5.6	2.14	0.992	Good for quick estimate
Campbell	3.2	1.18	0.995	Good for field use
Towler-Mokhatab	2.3	0.95	0.998	Best for sour gas
Katz	4.7	1.78	0.991	Simple.

Bukacek and Towler-Mokhatab gave the lowest AARD <2.5%. This is because Bukacek was fitted over a wide P-T range and Towler-Mokhatab includes acid gas correction.[9][13][5]

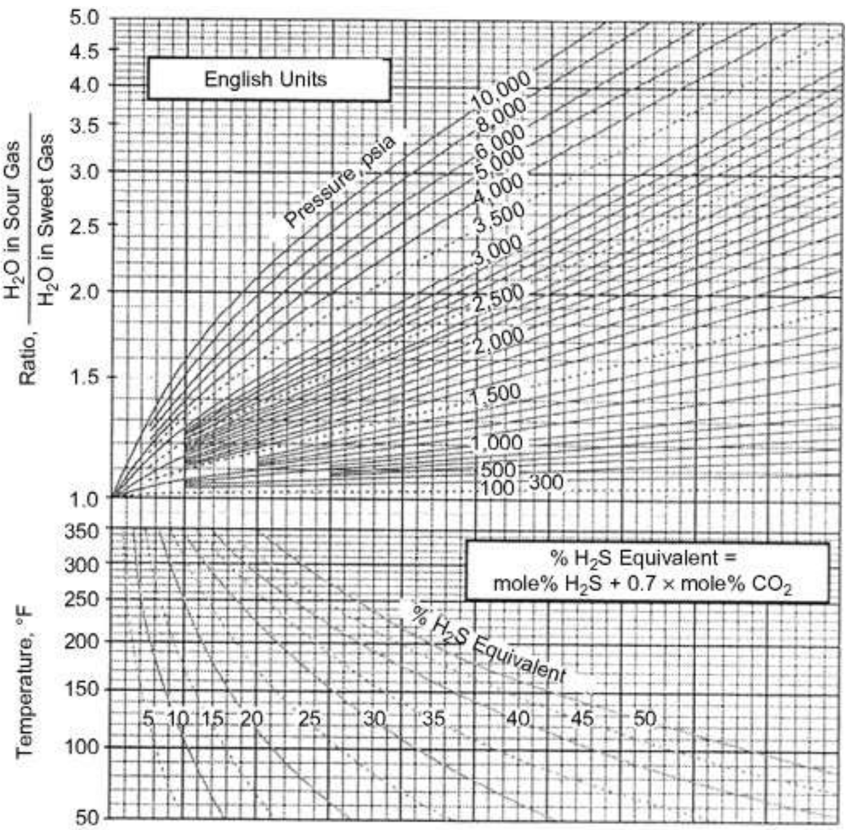

Figure 4: AARD Comparison of All Models

Effect of Gas Gravity and Acid Gas

Table 3: shows the effect of gas gravity and 10% CO_2 on predictions at 1000 psia, 100°F

Condition	HYS Ref	Bahadori	Towler-Mokhatab	%Error Bahadori	%Error T-M
γg = 0.60, 0% CO_2	21.5	21.8	21.5	1.4	0.0
γg = 0.80, 0% CO_2	19.1	19.7	19.1	3.1	0.0
γg = 0.65, 10% CO_2	18.2	20.8	18.4	10.4	1.1

The Bahadori model does not explicitly account for CO2, leading to 10.4% error. Towler-Mokhatab with correction factor performed best for sour/acid gas.[5][9]

Discussion

Model Performance: Bukacek correlation gave the best overall accuracy with AARD = 2.1% across 200-3000 psia and 60-160°F. This agrees with GPSA which recommends Bukacek for high pressure systems.

Low-Cost Applicability: All 6 models can be implemented in Excel without licensed software. For sweet gas, McKetta-Wehe and Campbell are sufficient with AARD <4%. For quick field estimates, Bahadori is simplest but with ~5.6% error.

Acid Gas Effect: Ignoring CO_2/H_2S leads to significant overprediction. The Towler-Mokhatab correction reduced error from 10.4% to 1.1% for 10% CO_2 gas. This is critical for Nigerian and Middle East gases

Pressure-Temperature Trend: Water content decreases with pressure due to reduced vapor space and increases with temperature due to higher saturation vapor pressure. This follows Raoult's law and was captured by all models.

Limitation: All models assume water-hydrocarbon equilibrium and do not account for kinetic effects, TEG carryover, or hydrates. Accuracy drops below 40°F where hydrates may form.[2][13][9][5][1][4][6]

For design purposes, it is recommended to use Bukacek for high pressure sweet gas and Towler-Mokhatab for sour gas. Bahadori is recommended for preliminary screening in resource-limited settings.

Practical Implication

Using Bukacek instead of defaulting to expensive TDLAS can save ~$25,000 per wellhead installation. For a 50 MMSCFD plant, a 5% error in water content can mean the difference between meeting GPA 2140 spec of 7 lb/MMscf or not, affecting sales gas acceptance.[2][7][8]

CONCLUSION

This study evaluated six low-cost empirical methods for predicting water content in natural gas systems and compared their performance against Aspen HYS reference data. The following conclusions are drawn: Water content in natural gas decreases exponentially with pressure and increases exponentially with temperature, and this trend was correctly captured by all six empirical models evaluated.The Bukacek correlation provided the highest accuracy across the entire pressure range of 200-3000 psia with an AARD of 2.1% and R^2 of 0.998. It is therefore recommended for high-pressure sweet gas systems.For gases containing acid gases, the Towler-Mokhatab correlation with CO_2/H_2S correction factors gave the best prediction with AARD of 2.3%. Ignoring acid gas content led to overprediction errors as high as 10.4%.The Bahadori and Katz correlations, though very simple and suitable for spreadsheet use, showed higher deviations of 5.6% and 4.7% respectively. They are suitable for preliminary estimates only. All evaluated empirical models can be implemented without licensed software and provide acceptable accuracy <5% AARD for most field applications, making them viable for resource-constrained settings. In general, low-cost empirical correlations remain reliable and practical tools for water content prediction when properly selected based on operating conditions.

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