Gas Lift Handbook

API RECOMMENDED PRACTICE 19GLHB
FIRST EDITION, JUNE 2020

ADDENDUM 1, MAY 2023



Documents
Document Sharing Hub

Full document details: API RP 19GLHB-2020 (2023)

Special Notes

API publications necessarily address problems of a general nature. With respect to particular circumstances, local, state, and federal laws and regulations should be reviewed. The use of API publications is voluntary. In some cases, third parties or authorities having jurisdiction may choose to incorporate API standards by reference and may mandate compliance.

Neither API nor any of API's employees, subcontractors, consultants, committees, or other assignees make any warranty or representation, either express or implied, with respect to the accuracy, completeness, or usefulness of the information contained herein, or assume any liability or responsibility for any use, or the results of such use, of any information or process disclosed in this publication. Neither API nor any of API's employees, subcontractors, consultants, or other assignees represent that use of this publication would not infringe upon privately owned rights.

API publications may be used by anyone desiring to do so. Every effort has been made by the Institute to ensure the accuracy and reliability of the data contained in them; however, the Institute makes no representation, warranty, or guarantee in connection with this publication and hereby expressly disclaims any liability or responsibility for loss or damage resulting from its use or for the violation of any authorities having jurisdiction with which this publication may conflict.

API publications are published to facilitate the broad availability of proven, sound engineering and operating practices. These publications are not intended to obviate the need for applying sound engineering judgment regarding when and where these publications should be used. The formulation and publication of API publications is not intended in any way to inhibit anyone from using any other practices.

Any manufacturer marking equipment or materials in conformance with the marking requirements of an API standard is solely responsible for complying with all the applicable requirements of that standard. API does not represent, warrant, or guarantee that such products do in fact conform to the applicable API standard.

All rights reserved. No part of this work may be reproduced, translated, stored in a retrieval system, or transmitted by any means, electronic, mechanical, photocopying, recording, or otherwise, without prior written permission from the publisher. Contact the Publisher, API Publishing Services, 200 Massachusetts Avenue, NW, Suite 1100, Washington, DC 20001.

Copyright © 2020 American Petroleum Institute

Documents
Document Sharing Hub

Full document details: API RP 19GLHB-2020 (2023)

Foreword

Nothing contained in any API publication is to be construed as granting any right, by implication or otherwise, for the manufacture, sale, or use of any method, apparatus, or product covered by letters patent. Neither should anything contained in the publication be construed as insuring anyone against liability for infringement of letters patent.

The verbal forms used to express the provisions in this document are as follows.

Shall: As used in a standard, “shall” denotes a minimum requirement in order to conform to the standard.

Should: As used in a standard, “should” denotes a recommendation or that which is advised but not required in order to conform to the standard.

May: As used in a standard, “may” denotes a course of action permissible within the limits of a standard.

Can: As used in a standard, “can” denotes a statement of possibility or capability.

This document was produced under API standardization procedures that ensure appropriate notification and participation in the developmental process and is designated as an API standard. Questions concerning the interpretation of the content of this publication or comments and questions concerning the procedures under which this publication was developed should be directed in writing to the Director of Standards, American Petroleum Institute, 200 Massachusetts Avenue, NW, Suite 1100, Washington, DC 20001. Requests for permission to reproduce or translate all or any part of the material published herein should also be addressed to the director.

Generally, API standards are reviewed and revised, reaffirmed, or withdrawn at least every five years. A one-time extension of up to two years may be added to this review cycle. Status of the publication can be ascertained from the API Standards Department, telephone (202) 682-8000. A catalog of API publications and materials is published annually by API, 200 Massachusetts Avenue, NW, Suite 1100, Washington, DC 20001.

Suggested revisions are invited and should be submitted to the Standards Department, API, 200 Massachusetts Avenue, NW, Suite 1100, Washington, DC 20001, standards@api.org.

Documents
Document Sharing Hub

Full document details: API RP 19GLHB-2020 (2023)

Documents
Document Sharing Hub

Full document details: API RP 19GLHB-2020 (2023)

Contents

Page

1 Scope . . . 1

2 Normative References . . . 1

3 Terms, Definitions, Abbreviations, and Symbols . . . 1
3.1 Terms and Definitions . . . 1
3.2 Abbreviations . . . 9
3.3 Symbols . . . 10

4 Introduction to Artificial Lift and Gas Lift . . . 14
4.1 Basic Principles of Hydrocarbon Production . . . 14
4.2 Artificial Lift System Basics . . . 15
4.3 The Process of Gas Lifting Liquids . . . 16
4.4 Choosing an Artificial Lift System . . . 16
4.5 Gas Lift System Types . . . 17
4.6 Continuous Gas Lift . . . 18
4.7 Intermittent Flow Gas Lift Systems . . . 19
4.8 Gas Lift for Gas Wells . . . 20
4.9 Major Components of a Typical Gas Lift System . . . 21
4.10 Advantages and Limitations of Gas Lift Systems . . . 25
4.11 Historical Review of Gas Lift System Developments . . . 27
4.12 Historical Development of Gas Lift Valve Designs . . . 28
4.13 Section Summary . . . 29

5 Well Performance, System Designs, and Operations . . . 29
5.1 General . . . 29
5.2 Well Performance (Inflow and Outflow) . . . 29
5.3 Gas Lift Well Performance Measurements . . . 44
5.4 Section Summary . . . 50

6 Multiphase Flow Predictions . . . 50
6.1 General . . . 50
6.2 Developing Multiphase Flow Correlations . . . 50
6.3 Dynamic Simulation Models for Gas Lift Systems . . . 63
6.4 Section Summary . . . 66

7 Gas Fundamentals and Facilities . . . 66
7.1 General . . . 66
7.2 Fundamentals of Gas Behavior . . . 67
7.3 Gas Measurement and Control . . . 68
7.4 Gas Applications within Oilfield Systems . . . 73
7.5 Surface Gas Facilities . . . 75
7.6 Section Summary . . . 86

8 Gas Lift System Design . . . 87
8.1 Introduction . . . 87
8.2 System Design Considerations . . . 87
8.3 Equipment Reference Documents . . . 102
8.4 Section Summary . . . 102

9 Overview of Specifications for Side-pocket Mandrels . . . 102
9.1 Introduction . . . 102
9.2 Functional Specifications . . . 105

AVA Documents
Document Sharing Hub

Full document details: API RP 19GLHB-2020 (2023)

Contents

Page

9.3 Technical Specifications . . . 106
9.4 Supplier/Manufacturer Requirements . . . 107
9.5 Section Summary . . . 108

10 Overview of Specifications for Flow-control Devices for Side-pocket Mandrels . . . 108
10.1 Introduction . . . 108
10.2 Functional Specifications . . . 110
10.3 Technical Specifications . . . 111
10.4 Supplier/Manufacturer Requirements . . . 112
10.5 Section Summary . . . 114

11 Continuous Flow Gas Lift Design Methods . . . 114
11.1 Introduction . . . 114
11.2 Continuous Flow Unloading Sequence . . . 115
11.3 Continuous Flow Installation Design Information . . . 117
11.4 Considerations for System Design . . . 117
11.5 Gas Lift Valve Design Examples . . . 129
11.6 Section Summary . . . 157

12 Unloading, Control, Testing, and Analysis of Continuous Flow Gas Lift Wells . . . 157
12.1 Introduction . . . 157
12.2 Unloading and Kickoff Recommendations . . . 157
12.3 Kickoff Pressures . . . 158
12.4 Unloading of Continuous Gas Lift . . . 158
12.5 Control Considerations . . . 162
12.6 Surface Data Indications and Actions . . . 165
12.7 Subsurface Data Indications and Actions . . . 167
12.8 Well Production Rate Testing . . . 170
12.9 Production Optimization for the Available Gas Lift Gas . . . 176
12.10 Section Summary . . . 177

13 Intermittent Flow Gas Lift . . . 177
13.1 Introduction . . . 177
13.2 General Description of Intermittent Flow Gas Lift . . . 177
13.3 Changing from Continuous to Intermittent Flow Gas Lift . . . 178
13.4 Types of Intermittent Gas Lift Installations . . . 178
13.5 Control Methods for Intermittent Gas Lift Wells . . . 182
13.6 Design Considerations for Intermittent Gas Lift Installations . . . 184
13.7 Dynamic (Transient) Models for Intermittent Gas Lift Design Calculations . . . 186
13.8 Mandrel Spacing Example . . . 186
13.9 Section Summary . . . 192

14 Unloading, Control, Analysis, and Optimization of Intermittent Flow Gas Lift . . . 193
14.1 Introduction . . . 193
14.2 Unloading an Intermittent Installation . . . 193
14.3 Control Considerations . . . 195
14.4 Adjustment of Cycle Time for Operation . . . 196
14.5 Analysis of System and Well Performance . . . 203
14.6 Optimization Challenges . . . 207
14.7 Section Summary . . . 207

15 Design and Operation of Dual Gas Lift Wells . . . 207

AVA Documents
Document Sharing Hub

Full document details: API RP 19GLHB-2020 (2023)

Contents

Page

15.1 Dual Gas Lift Overview . . . 207
15.2 Dual Gas Lift Production . . . 209
15.3 Candidates for Dual Gas Lift Wells . . . 210
15.4 Operational Guidelines . . . 210
15.5 Design and Installation . . . 211
15.6 Mandrel Spacing . . . 211
15.7 Optimizing Dual Gas Lift Wells . . . 222
15.8 Section Summary . . . 223

16 Gas Lift System Troubleshooting Guidelines . . . 223
16.1 Introduction . . . 223
16.2 Gas Lift System Troubleshooting and Correction Guidelines . . . 225
16.3 Section Summary . . . 266

17 Gas Lift Automation . . . 266
17.1 Introduction . . . 266
17.2 Automation Objectives and Practices . . . 266
17.3 Gas Lift Automation Hardware and Software . . . 268
17.4 Section Summary . . . 270

Bibliography . . . 271

Figures

4.1 Production Process in an Oil or Gas Well . . . 14
4.2 Artificial Lift with Pumps . . . 16
4.3 Production from Natural Flow and Gas Lift Wells . . . 17
4.4 Continuous and Intermittent Gas Lift . . . 18
4.5 Static and Gas Lift Pressure Gradients in the Wellbore . . . 19
4.6 Gas Lift Methods to Remove Liquids from Gas Wells . . . 20
4.7 Gas Lift System, Supply Gas, Subsurface, and Fluid Gathering Components . . . 21
4.8 Subsurface Equipment with Mandrels and Gas Lift Valves (IPO) . . . 24
4.9 King Gas Lift Valve (IPO) . . . 28
5.1 Reservoir Symbols for Darcy Equation . . . 32
5.2 Vogel IPR Curve . . . 33
5.3 Reservoir Inflow Performance . . . 36
5.4a Inflow-Outflow Performance—Natural Flow . . . 37
5.4b Inflow-Outflow Performance—Pumps . . . 38
5.4c Inflow-Outflow Performance—Gas Lift . . . 38
5.5 Vertical Flowing Pressure Gradients (All Oil) . . . 39
5.6 Inflow and Outflow—Increasing IGLR Reduces Density and Outflow Pressure . . . 40
5.7 Gas Lift Well Performance Curve—Production Rate vs Injection Gas Rate . . . 41
5.8 Production and Gas Gradients from Well Performance Curve Rate . . . 41
5.9 Inflow and Outflow Performance . . . 42
5.10 Gas Lift Well Performance vs Injection Gas Rate . . . 43
5.11 PVT Estimates from Pressure Gradients . . . 46
6.1 Flow Patterns in Wellbore . . . 51
6.2 Flow Pattern Images and Map for Vertical Flow . . . 52
6.3 Flow Pattern Images and Map for Horizontal Flow . . . 52
6.4 Flow Pattern Map Variations with Inclination Angle . . . 53
6.5a Dukler H_L Correlation . . . 58

Documents
Document Sharing Hub

Full document details: API RP 19GLHB-2020 (2023)

Contents

Page

6.5b Dukler f_{tpr} Correlation . . . 59
6.6 Vertical Lift Performance Curve for a Specific Tubing Size . . . 60
6.7 Multiphase Outflow Stability Compared to Inflow Capacity for Tubing Size Selection . . . 61
6.8 Multiphase Flow Calculations Generate Gradients for Specific Rate and Tubing Size . . . 62
7.1 Orifice Meter . . . 69
7.2 Example of Sonic Meter . . . 71
7.3 Injection Gas Gradients . . . 74
7.4 Hydrate Prediction for Un-dehydrated Gas . . . 76
7.5 Water Vapor Content for Gas . . . 78
7.6 Horsepower Required to Compress 1 Million Standard Cubic Feet per Day . . . 83
7.7 Gas Lift Gas Distribution Options . . . 85
8.1 Gas Lift System Design Components . . . 88
8.2 Gas Lift Wellbore Components . . . 95
9.1 Side-pocket Mandrel . . . 103
9.2 Side-pocket Mandrel Components . . . 103
9.3 Example Side-pocket Mandrel with Gas Lift Valve Inserted . . . 104
10.1 Flow-control Device (Gas Lift Valve) Components . . . 109
11.1 Unloading the Initial Control Fluid from Casing and Tubing . . . 116
11.2 Design Bias Examples . . . 119
11.3 IPO Gas Lift Valve Schematic with Areas and Pressures and in Mandrel . . . 121
11.4 Flowing Temperature Gradient . . . 125
11.5 Gas Passage Chart for Various Orifice Sizes . . . 128
11.6 Gas Lift Valve Flow Rate . . . 128
11.7 Gas Lift Well Data Sheet—Example 1 . . . 131
11.8 Vertical Flowing Pressure Gradients (50 % Oil, 50 % Water) . . . 132
11.9 Nodal Analysis Plot of Inflow and Outflow Pressures . . . 133
11.10 Gas Lift Performance Graph . . . 133
11.11 Injection Gas Gradients . . . 136
11.12 Start of a Graphical Gas Lift Design . . . 138
11.13 Top Valve Depth Determination . . . 139
11.14 Second Valve Depth Determination . . . 140
11.15 Gas Lift Design Spacing 2 7/8 in. Tubing (2.5 in. ID), 800 BLPD, 50 % WC, 1000 scf/stb R_{gl} . . . 143
11.16 Example Gas Lift Valve Test Rack . . . 144
11.17 Example 2 Well Data Sheet . . . 149
11.18 Graphical Straight-line Mandrel Spacing Basics for Gas Lift Design Example with Limited Data . . . 150
11.19 Mandrel 2 Spacing Location . . . 152
11.20 Example 2—Graphical Design Line Mandrel Spacing . . . 154
12.1 Unloading a Continuous Flow Gas Lift Well—Circular and Linear Pressure Charts . . . 161
12.2 Unloading a Continuous Flow Gas Lift Well—Strip Chart Illustration . . . 162
12.3 Choke Control System . . . 164
12.4 Flow Rate Control Valve . . . 165
12.5 Pressure vs Depth Data . . . 169
12.6 Temperature vs Depth Data . . . 169
12.7 Gas Lift Gas Utilization, bbl/million scf . . . 173
12.8 Gas Lift Gas Utilization vs TGLR . . . 174
13.1 Illustration of Intermittent Lift Installation with Time-cycle Controller . . . 179
13.2 Chamber Installation Options: Two Packers, Large Tubing . . . 180
13.3 Plunger Added to Intermittent Installation . . . 180
13.4 Illustration of Starting Slug and Fallback . . . 181

AVA Documents
Document Sharing Hub

Full document details: API RP 19GLHB-2020 (2023)

Contents

Page

13.5 Choke Control of Intermittent Lift 182
13.6 Time-cycle Control of Intermittent Lift 183
13.7 Illustrations of IPO Valves and IPO Pilot Valves 184
13.8 Intermittent Lift Spacing Factors for Design 187
13.9 Graphical Straight-line Mandrel Spacing Basics for Intermittent Gas Lift Example. 188
13.10 Mandrel 2 Spacing Location 189
13.11 Graphical Spacing Factor Mandrel Spacing 191
14.1a Pressure Build at Perforations vs Time. 197
14.1b Gradient Survey with Shallow Point of Lift 197
14.2a Pressure Build at Perforations vs Time. 198
14.2b Gradient Survey with Deep Point of Lift 198
14.3 Pressure Build at Multiple Depths in a Research Well 199
14.4 Lift Gas and Fallback per 1000 ft of Lift 200
14.5 Intermittent Lift Wellhead with Streamlined Piping 202
14.6 Wellhead Pressure Plot Segments 203
14.7 Choke Control Gas Injection Pressure Plot Segments 204
14.8 Time-cycle Control Gas Injection Plot Segments 204
14.9a Intermittent Well Test Data 206
14.9b Gas Utilization Factor (GUF). 206
15.1 Dual Gas Lift with Common Annulus Equipment 208
15.2 Dual Gas Lift Pressure Graph 208
15.3 Graphical Design Line Mandrel Spacing Basics for PPO Unloading Valve Example. 215
15.4 Spacing Location of the Second Unloading Mandrel 216
15.5 PPO Example—Graphical Design Line Mandrel Spacing 217
15.6 PPO Valve Schematics and Crossover Seat Example. 218
15.7 Test Rack Schematic for Valve with Crossover Seat. 221
16.1 Gas Lift System Components Example 225
16.2 Continuous Gas Lift—Tubing Integrity Test for Casing-tubing Leak. 229
16.3 Continuous Gas Lift—Hydrates at Choke. 231
16.4 Continuous Gas Lift—Instability in Casing and Tubing 233
16.5 Continuous Gas Lift—Instability in Tubing 234
16.6 Continuous Gas Lift—Excessive Wellhead Back-pressure 236
16.7 Intermittent Gas Lift—Time-cycle Control 238
16.8 Intermittent Gas Lift—Choke Control 239
16.9 Intermittent Gas Lift—Time-cycle Control 240
16.10 Intermittent Gas Lift—Time-cycle Control. 241
16.11 Pressure/Temperature Flowing Survey with Stops Above and Below the Valves 242
16.12 Expanded Temperature Flowing Survey with Stops Above and Below the Valves 243
16.13 Pressure/Temperature Flowing Survey with Stops Above and Below the Valves 244
16.14 Expanded Temperature Flowing Survey with Stops Above and Below the Valves 244
16.15 Pressure/Temperature Flowing Data at Stop Points 245
16.16 Expanded Temperature Flowing Data at Stop Points 245
16.17 Pressure/Temperature Data—Continuous vs Time 246
16.18 Expanded Temperature Data—Continuous vs Time 246
16.19 Flowing Survey vs Time—Intermittent Lift with Stops Below the Valves 247
16.20 Pressure/Temperature Flowing Survey—Intermittent Lift with Stops Below the Valves 247
16.21 Expanded Temperature Flowing Survey—Intermittent Lift with Stops Below the Valves 248
16.22 Temperature Data from DTS Cable—Pre-unloading, Unloading, and Production. 248
16.23 CO_2 Tracer Equipment 249

Documents
Document Sharing Hub

Full document details: API RP 19GLHB-2020 (2023)

Contents

Page

16.24 Tracer Results—CO_2 Concentration % vs Time and Valve Depths 250
16.25 CO_2 Tracer Results—Well History 251
16.26 Acoustic Reflections Matched to Valve Mandrels 252
16.27 Acoustic Reflections Inside and Outside the Valve Mandrels. 252
16.28 Acoustic Reflections in the Tubing and Casing 253
16.29 Production vs Injection Gas (Optimization Curve) at Various Mandrel Depths. 254
16.30 Continuous Gas Lift—Good Operation 256
16.31 C-4 Measured Temperature Data 258
16.32 C-4 Measured Pressure Data 259
16.33 GOR—Adjusted to Match Measured Gradient Data 259
16.34 Delivery Data with Adjusted GOR vs Test Point 260
16.35 C-16 Wellbore Sketch 261
16.36 C-16 Two-pen Chart During Survey 264
16.37 C-16 Measured Pressure and Simulation 265
16.38 C-16 Production Rate vs Injection Gas Rate 265
17.1 Automation Schematic 270

Tables

3.1 Cross-reference of Gas Lift Symbols 10
5.1 Example Outflow Data 40
5.2 PVT Report Data 44
5.3 PVT Reports and Data Variation 45
5.4 A Guide to Purge and Rate Stability Time Based on Productivity Index (PI) 48
7.1 Basic Orifice Factor F_b for D (Pipe ID) and d (Orifice ID). 70
8.1 General Design Strategies Summary 89
11.1 Gas Lift Valve Data—Monel Seats 123
11.2 Guidelines for Pressure Drop (P_{drop}) Between Unloading Valves 124
11.3 Temperature Correction Factors for Nitrogen Gas 126
11.4 Inflow Rates for Various P_{wf}. 130
11.5 Bottomhole Outflow Pressure at Each Production Rate for Various R_{gl} 132
11.6 Flowing Tubing Pressures for 800 BLPD Production Rate at 50 % WC and 1000 R_{gl} 137
11.7 Calculated, Graphical, and Adjusted Depths 141
11.8 Valve Closing Pressures at Surface ($P_{sc(n)}$) and at Valve Depth ($P_{cd(n)}$) 145
11.9 Summary of Test Rack Pressures 146
11.10 Calculated and Adjusted Depths—Example 2 153
11.11 Data at Each Valve Depth—Example 2 155
11.12 Summary of Test Rack Pressures—Example 2 156
12.1 Time Increments Associated with the Pressure Rise 159
12.2 Gas Rates Equal to 1 bbl/min 160
12.3 Annulus Displacement Capacity and Time Equal to 1 bbl/min. 160
12.4 Production Test Data and Calculations of KPIs. 173
13.1 Calculated and Adjusted Depths—Intermittent Lift 190
13.2 Summary of Test Rack Pressures 192
14.1 Data from an Intermittent Installation 200
14.2 Well Test Data and Calculations 205
15.1 PPO Example Well Parameters 212
15.2 Gas Lift Valve and Mandrel Characteristics 213
15.3 Calculated and Adjusted Depths—PPO Example 217
15.4 Pressure and Temperature Data—PPO Example. 219

AVA Documents
Document Sharing Hub

Full document details: API RP 19GLHB-2020 (2023)

Contents

Page

15.5 Test Rack Pressures—PPO Example with Nitrogen-charged Bellows 220
15.6 Test Rack Pressures—PPO Example with Spring Tension Closing 221
15.7 Calculated Long String Mandrel Depths 222
15.8 Duplicated Short String Mandrel Depths 222
16.1 Wells Not Taking Lift Gas 226
16.2 Wells Circulating Gas 227
16.3 Well Leak Identification 228
16.4 Potential Solids Plugging 230
16.5 Well Instability 232
16.6 Underperformance by Shallow Lifting 235
16.7 Low Production in Intermittent Lift Applications 237
16.8 Example KPIs for Continuously Injected Oil Wells 254
16.9 Test Objective Terminology 255
16.10 Test Data for Well C-4 257
16.11 Measured Gradient Data for Well C-4 258
16.12 Test Data for Well C-16 262
16.13 Measured Gradient Data for Well C-16 263

Documents
Document Sharing Hub

Full document details: API RP 19GLHB-2020 (2023)

Introduction

This document has been developed based upon the content of the API Gas Lift Book 6 of the Vocational Training Series, Third Edition, 1994. The third edition was based upon evolutionary information which was initiated with the first edition dated 1965.

Gas lift systems provide a means of enhancing the natural production of hydrocarbons from a producing oil or gas well. Gas lift is widely used because of its broad spectrum of capabilities to increase the production volumes. This handbook has been assembled to provide the reader with a fundamental knowledge of the general aspects required within a gas lift system. This information has been provided by industry experts and contains many technical perspectives and approaches. The 16 sections of this handbook contain the tutorial information and data that has been compiled from numerous API specifications and recommended practices. While this handbook includes foundational data, good engineering judgment and local work practices are essential to supplement this information.

Due to the historical nature of the source documents, the terminology, abbreviations, and symbols have been merged and harmonized. Section 3 includes the definitions and symbols utilized within this technical report.

Section 4 provides an introduction to the basic principles of gas lift. The subject areas include artificial lift systems basics, gas lift system types, and the major components of a gas lift system. The advantages and limitations of gas lift are provided to aid the selection of an appropriate lift method. A brief review of gas lift system development provides a historical perspective on the method.

Subsequent sections of this handbook provide the following: fundamentals of well performance, multiphase flow prediction, gas fundamentals and facilities, gas lift mandrels, relevant tools, valves, system design, continuous, intermittent, dual well flow design methods and analyses and troubleshooting of gas lift wells.

Documents
Document Sharing Hub
Full document details: API RP 19GLHB-2020 (2023)

Documents
Document Sharing Hub

Full document details: API RP 19GLHB-2020 (2023)

Gas Lift Handbook

1 Scope

This document presents information on the following topics related to gas lift equipment:

a) the basic principles of gas lift;

b) gas lift equipment selection;

c) how various types of gas lift equipment work;

d) how a gas lift system should be designed.

Information is also included on monitoring, adjusting, regulating, and trouble-shooting gas lift equipment. It is intended to familiarize operating personnel with the use of gas lift as an artificial lift system.

2 Normative References

No other document is required for the application of this standard. A list of documents associated with API 19GLHB are included in the Bibliography.

3 Terms, Definitions, Abbreviations, and Symbols

3.1 Terms and Definitions

For the purposes of this document, the following terms and definitions apply.

3.1.1
acceptance
Agreement or acknowledgment that the component or assembly can be used without restriction.

3.1.2
annulus
Concentric space that exists between the tubing and the production casing of the well.

3.1.3
API oil gravity
Specific gravity of a liquid as defined by using API methodology.

3.1.4
asphaltenes
Heavy fraction of crude oil consisting of aromatic and naphthenic compounds that often adhere to wetted components during production and that are not soluble in straight-chain solvents.

3.1.5
black oil correlation
Mathematical equations describing crude oil properties at a range of conditions defined by laboratory evaluations of reservoir oils as distinguished from compositional models for light hydrocarbons.

3.1.6
bubble point pressure
The pressure (at a given temperature) where the first bubble of vapor is formed when pressure is reduced in a liquid.

Documents
Document Sharing Hub
Full document details: API RP 19GLHB-2020 (2023)

3.1.7
calibration
Comparison and adjustment of measuring equipment or a process to a defined level of accuracy.

3.1.8
chamber lift
Intermittent lift that uses two packers or a section of large tubing to create an accumulation chamber.

3.1.9
choke
Equipment used to restrict or control the flow of fluids.

3.1.10
choke bean size
Size of the replaceable orifice utilized within a choke.

3.1.11
closed system
Gas lift system when the produced gas is reused as lift gas.

3.1.12
compressive load
Force creating compression that can be applied to a side-pocket mandrel.

3.1.13
conduit
Tubular product designed for the flow of fluids.

3.1.14
Darcy model
Productivity index (PI) equations that describe the flow of a fluid through a porous medium.

3.1.15
design bias
A range of conditions and applied equations involved in the engineering development of the gas lift system to ensure the desired performance (formerly termed as safety factor).

3.1.16
design family
Group of products whose configurations, sizes, materials, and applications are sufficiently similar that identical design methodologies can be used to establish the design parameters for each product within the family.

3.1.17
design method
Practices, procedures, or equations used by the supplier/manufacturer to design a device or product.

3.1.18
design validation
Process of proving a design by testing to demonstrate conformity of the product to design requirements.

3.1.19
design validation grade
Levels of design requirements for side-pocket mandrels and associated equipment, in accordance with API 19G1, API 19G2, and API 19G3.

Documents
Document Sharing Hub
Full document details: API RP 19GLHB-2020 (2023)

3.1.20
design verification
Process of examining the result of a given design to determine conformity with specified requirements.

3.1.21
deviation
Wellbore inclination in degrees from true vertical.

3.1.22
distributed temperature survey
DTS
Temperatures taken contiguously throughout a well.

3.1.23
dogleg
Change in wellbore inclination typically measured in degrees or a specified distance.

NOTE A severe change in angle is called a tubing kink.

3.1.24
dome
Chamber that contains an internal pressure that is applied to the responsive element.

NOTE The responsive element can be a bellows or piston.

3.1.25
drawdown
The difference between reservoir pressure and flowing bottomhole pressure (FBHP) at a defined rate.

3.1.26
dry bed mole sieve unit
A device with porous medium that segregates water vapor from gas vapor.

3.1.27
dummy valve
Blank device that is installed in a side-pocket mandrel to prevent flow or pressure communication between the casing annulus and tubing.

3.1.28
dynamic flow testing
Flow testing of an operable flow-control device to determine the fluid flow characteristics as a function of changes in either upstream or downstream pressures at a known temperature.

3.1.29
environmental service
Category of environmental conditions that a covered product is designed to be used in.

3.1.30
external drift test
Test to observe the unencumbered or unrestricted passage of a side-pocket mandrel having a specific diameter through a drift test tool of specified inside diameter (ID) and length.

3.1.31
flow coefficient
A relative measure of a device's efficiency to allow fluid flow. It describes the relationship between the pressure drop across an orifice, valve, or other assembly and the corresponding flow rate.

AVA Documents
Document Sharing Hub
Full document details: API RP 19GLHB-2020 (2023)

3.1.32
flow-control device
A device installed on or in a mandrel to control flow of fluids typically between a well's casing annulus and tubing.

3.1.33
flowing bottomhole pressure
FBHP
Pressure measured at the point of inflow to the producing conduit of the well when the well is under production from the reservoir through the completion.

3.1.34
flowing pressure gradient
The measured pressure difference of flowing fluid in a conduit over a specified true vertical distance that is typically measured in psi per foot.

3.1.35
flowline
Piping system extending from wellhead valves to the production process.

3.1.36
force balance equation
A method of using balanced force when the valve closes during initial unloading to calculate the nitrogen pressure required to close the valve.

3.1.37
functional test
Test performed to confirm proper operation of equipment.

3.1.38
gas-cap gas
The reservoir gas that accumulates in the upper portions of the reservoir due to density segregation.

3.1.39
gas compression deviation factor
Z
Compressibility factor that indicates a deviation from the ideal gas laws.

3.1.40
gas passage undercut
Clearance between the flow-control device and the pocket of the side-pocket mandrel where injected media flows.

3.1.41
gas port
Holes in a side-pocket mandrel pocket where gas enters.

3.1.42
gas specific gravity
Ratio of the mass of a specified volume of gas at a defined pressure and temperature, when compared to that of air.

3.1.43
heading
slugging
Exhibiting pressure surging of sufficient intensity to cause production system upsets.

NOTE Not to be confused with slug flow pattern.

Documents
Document Sharing Hub
Full document details: API RP 19GLHB-2020 (2023)

3.1.44
hydrates
An organic crystalline compound containing water and hydrocarbons that solidifies at decreased temperature and increased pressure.

3.1.45
informative
Information provided to increase the awareness of the user/purchaser or supplier/manufacturer; however, it is not required for compliance with this specification.

3.1.46
injection pressure operated
IPO
A device that has the injection pressure as its primary operating pressure to control the device.

3.1.47
instability
Nonuniform flow in its rate, volume, and/or pressure.

3.1.48
intermitter
A time-cycle controller used to control injection of gas into a producing gas lift well to initiate periodic well production.

3.1.49
internal drift test
Test to observe the unencumbered or unrestricted passage of a drift bar having a specific diameter and length.

3.1.50
kill fluid
Weighted fluid pumped into the well to halt production from the reservoir.

3.1.51
latch
Mechanism for installation, retention, or removal of a flow-control device that is landed in a side-pocket mandrel latch profile.

3.1.52
loading conditions
Anticipated loads on a device.

NOTE Can include tensile and compressive loads, internal (burst) pressures, external (collapse) pressures, bending stresses, and others.

3.1.53
low-pressure separator
A separator that uses the lowest practical pressure to separate liquids from gas, typically less than 100 psi.

3.1.54
mechanical scraping
The act of reducing the accumulations within a production tubular by the running of an edged tool to loosen the accumulated paraffin, asphaltenes, or other scale-like accumulations to improve production flow or clean the casing.

Documents
Document Sharing Hub
Full document details: API RP 19GLHB-2020 (2023)

3.1.55
model
Products with unique components and functional characteristics that differentiate it from other products of the same type; wellbore and surface piping components included in multiphase flow nodal analysis.

3.1.56
nodal analysis
A complex set of equations used to model the performance of gas lift well hydraulic behavior from the reservoir to the production separator at individual points (nodes).

3.1.57
nomograph
Diagram representing the relationships between three or more quantities by means of a number of scales, arranged that the value of one variable can be identified by a geometric form.

3.1.58
normative
Provisions or elements that are to be followed to comply with a standard.

3.1.59
operating environment
Environmental conditions that the product is exposed to during its service life, such as temperature, pressure, liquid and gas composition and properties, solids, and others.

3.1.60
operational parameter
Requirement or restriction that the product is exposed to during its service life, which can include operating environment, landing and retrieval of flow-control devices, injection of various well treatment chemicals/fluids, and others.

3.1.61
orienting profile
Design feature (e.g. orienting sleeve) of a side-pocket mandrel that acts together with certain wireline tools to aid in radial and vertical alignment of tools used to install and remove side-pocket landed equipment.

3.1.62
orifice
A restriction used to measure flow or to control pressure or flow.

NOTE The device can include a square edged port or a venturi-shaped port.

3.1.63
packoff
Retrievable hydraulic isolation device that can be set in tubing to enable gas lift or isolate a hole.

3.1.64
pilot valve
Injection-pressure-operated (IPO) gas lift valve with a primary opening section that activates the full-opening flow section to enable a large volume of gas to be injected for a short period of time.

3.1.65
plunger
A tool that is dropped without attachment through the well tubing to minimize mixing at the gas-liquid interface.

NOTE The well production or gas lift differential pressure below the plunger lifts liquid from the well.

Documents
Document Sharing Hub
Full document details: API RP 19GLHB-2020 (2023)

3.1.66
pocket
Side-pocket mandrel bore, including sealing surfaces and latching profiles, that is offset from and parallel with the through-bore.

3.1.67
productivity index
PI
J
Production rate divided by drawdown, or differential pressure between static and FBHPs.

3.1.68
production pressure operated
PPO
A device that has the produced fluid as its primary operating pressure to control the device.

3.1.69
pulling tool
Device that connects to a flow-control assembly latch fishing neck to facilitate its retrieval from a side-pocket mandrel.

3.1.70
qualified person
An individual with skills and abilities to perform the required function gained through training or experience or both as measured against established requirements such as standards or tests.

3.1.71
quality control
Processes or method(s) that are used by the supplier/manufacturer to ensure the quality of the materials and manufacturing process(es).

3.1.72
rated pressure
Maximum differential pressure, at the rated temperature, the product is designed to function within.

3.1.73
rated temperature
Maximum temperature at a specified pressure that the product is designed to operate in.

3.1.74
running tool
Device that connects to a flow-control assembly latch running head to facilitate its installation into a side-pocket mandrel.

3.1.75
sample chamber
A device used to collect pressurized production fluid samples for analysis.

3.1.76
side-pocket mandrel
Tubing-mounted device that accepts a flow-control or other device in a bore that is offset from, and parallel with, the through-bore of the tubing product.

Documents
Document Sharing Hub
Full document details: API RP 19GLHB-2020 (2023)

3.1.77
significant design changes
Change to the design identified by the supplier/manufacturer that can affect the performance of a product and the intended service condition.

3.1.78
skin
Porosity or permeability variations caused by well operations in the near wellbore reservoir surfaces (sandface).

3.1.79
sour gas
A gas that contains significant amounts of hydrogen sulfide, which is corrosive to most oilfield materials and toxic to humans.

3.1.80
supervisory control and data acquisition system
SCADA
Remote monitoring and control that operates with coded signals through communication channels.

3.1.81
supplier/manufacturer
Company, organization, or entity that designs, manufactures, or markets products covered by this specification.

3.1.82
tail gas
The trailing gas following an intermittent production liquid slug.

3.1.83
technical specifications
Requirements necessary for compliance with the functional specification, which include parameters and limits to ensure the product and component performance.

3.1.84
tensile load
Force creating tension that can be applied to a side-pocket mandrel as defined by the supplier/manufacturer.

3.1.85
test pressure
Differential pressure between the applied pressure and atmospheric pressure, as specified by the pertinent test procedure that is based upon relevant design criteria.

3.1.86
test temperature
Temperature at which the equipment is tested to a specified procedure.

3.1.87
thick slug
Tubing pressure profile depicting a small volume of liquid and a higher volume of gas; characterized by the inefficient lifting of a liquid slug in intermittent gas lift.

3.1.88
tool string
Assembly of components required to run or retrieve a flow-control device.

Documents
Document Sharing Hub
Full document details: API RP 19GLHB-2020 (2023)

3.1.89
traceability
The ability to identify component or assembly or material processing history.

3.1.90
tubing-retrievable mandrel
conventional mandrel
Mandrel designed to contain a flow-control device that requires the tubing to be pulled to install or retrieve the flow-control device.

3.1.91
type (noun)
Products with characteristics that differentiate them from other functionally similar products that have unique names or descriptions.

3.1.92
underperform
To provide less produced fluids than expected or required.

3.1.93
U-tube
Two vertical columns of fluid (casing/tubing) with fluid communication at one or more points, where injected gas is displacing liquid from the annulus to the tubing.

3.1.94
velocity string
Small-diameter tubing run inside the production tubing of a well as a remedial treatment to resolve liquid loading by decreasing area resulting in a velocity increase.

3.1.95
venturi orifice
Device that is intended to restrict flow to a desired rate that reaches critical velocity at given conditions and allows no additional flow regardless of reduction in downstream pressure.

3.1.96
Vogel model
Equation that describes the flow of a fluid through a porous medium for oil wells producing below the bubble point.

3.1.97
welding
Method for joining two metallic substances through a process of melting and re-solidification.

3.1.98
Wireline
slick line
Equipment and associated technique(s) used to install and retrieve flow-control devices in a side-pocket mandrel using a continuous length of stranded or solid wire, surface spooling and measurement equipment, and specialized tools attached to the downhole end of the wire.

3.2 Abbreviations

BLPD	barrels of liquid produced per day
BOEPD	barrels oil equivalent per day
BWPD	barrels water per day
DCS	distributed control system

Documents
Document Sharing Hub
Full document details: API RP 19GLHB-2020 (2023)

DTS	distributed temperature survey
EOR	enhanced oil recovery
ESD	emergency shutdown
FBHP	flowing bottomhole pressure
FCV	flow-control valve
FGS	flowing gradient survey
GOR	gas-oil ratio
ID	inside diameter
IP	internet protocol
IGLR	injection gas-liquid ratio
IPO	injection pressure operated
IPR	inflow performance relationship
KPI	key performance indicator
MCFD	thousand cubic feet per day
NGL	natural gas liquid
OD	outside diameter
PI	productivity index
PLC	programmable logic controller
PPO	production pressure operated
PVT	pressure-volume-temperature
RTU	remote terminal unit
SBHP	static bottomhole pressure
TEG	triethylene glycol
TGLR	total gas-liquid ratio
TVD	true vertical depth
WC	water cut fraction

3.3 Symbols

Table 3.1 is a cross-reference of symbols used in this document to previous uses in other industry gas lift documents.

Table 3.1—Cross-reference of Gas Lift Symbols

API 19GLHB	Description	Units	Formerly Expressed As			
			API Book 6	API 19G2	API 11V6	SPE
A_b	area of bellows—based on average diameter	in.^{2}	A_b	A_b	A_b	A_b
A_p	area of valve port	in.^{2}	Ap	A_p	A_p	A_p
A_s	area of valve port-ball seat contact	in.^{2}	—	A_s	—	—
C_t	temperature correction factor for nitrogen gas	—	Ct	F_{tc}	C_T	F_T

Documents
Document Sharing Hub
Full document details: API RP 19GLHB-2020 (2023)

API 19GLHB	Description	Units	Formerly Expressed As			
			API Book 6	API 19G2	API 11V6	SPE
D	depth	ft	—	D	—	D
D_m	measured depth of deviated wells	ft	—	D_m	D_m	—
$D_{(n)}$	depth on n^{th} valve	ft	$D_{(n)}$	$D_{(n)}$	$D_{(n)}$	—
D_{port}	port diameter of the gas lift valve	1/64 in.	ck	Dport	ck	—
D_{tv}	true vertical depth of well	ft	—	D_{tv}	D_{tv}	D
D_w	reference depth of well: normally measured midpoint of perforations, or top of perforations	ft	Dw	D_w	D_w	—
$D_{(1)}$	depth of top valve	ft	$D_{(1)}$	$D_{(1)}$	$D_{(1)}$	D_1
d	diameter	in.	—	d	—	d
F_c	closing force on gas lift valve	lbf	Fc	F_c	F_c	—
F_o	opening force on valve	lbf	Fo	F_o	F_o	—
F_{o1}	opening force due to pressure on the bellows	lbf	$Fo1$	F_{o1}	F_{o1}	—
F_{ppe}	production pressure effect factor—manufacturing data—(previously TEF)	—	$PPEF$	$Rtef$	P_{PEF}	F_p
f_o	oil cut fraction of total produced liquid	(fraction)	fo	f_o	f_o	f_o
f_w	water cut fraction of total produced liquid	(fraction)	fw	f_w	f_w	f_w
G	gradient	psi/ft	g	G	g	—
G_{fa}	flowing gradient above point of gas injection	psi/ft	gfa	G_{fa}	g_{fa}	gfp
G_{fb}	flowing gradient below point of gas injection	psi/ft	gfb	G_{fb}	g_{fb}	g_{fb}
G_g	gas gradient of injection gas	psi/ft	gg	G_g	g_g	—
G_s	static gradient of liquid load fluid	psi/ft	gs	G_s	g_s	—
G_{sf}	production spacing factor gradient	psi/ft	—	—	—	—
J	productivity index (J = PI)	BLPD/psi, bpd/psi	J	J	J	J
L	distance	ft	D	L	D	L
L_{bv}	distance between valves	ft	D_{bv}	L_{bv}	D_{bv}	L_{bv}
P_{bp}	bubble point pressure of the produced oil	psig	P_B	P_B	P_B	P_B
$P_{bt(n)}$	bellows pressure at temperature of n^{th} valve	psig	$P_{bt(n)}$	$P_{bt(n)}$	$P_{bt(n)}$	P_{bvd}
P_{b60}	bellows pressure at 60 °F	psig	Pbv	P_{b60}	P_{bsc}	p_b
$P_{cd(n)}$	valve closing gas injection pressure of n^{th} valve at depth	psig	$Pvcd(n)$	$P_{vcd(n)}$	$P_{vcd(n)}$	$p_{vcD(n)}$

AVA Documents
Document Sharing Hub
Full document details: API RP 19GLHB-2020 (2023)

API 19GLHB	Description	Units	Formerly Expressed As			
			API Book 6	API 19G2	API 11V6	SPE
$P_{cd(1)}$	valve closing gas injection pressure of Valve 1 at depth	psig	*Pvcd(1)*	$P_{vcd(1)}$	$P_{vcd(1)}$	$p_{vcD(1)}$
P_{db}	pressure design bias (safety factor) to ensure valve is uncovered	psig	*PSF*	P_{db}	P_{SF}	—
P_{dl}	design line pressure at surface	psig	—	P_{dl}	P_{dl}	p_{dl}
P_{dld}	design line pressure at depth	psig	—	P_{dld}	P_{dld}	p_{dlD}
P_{drop}	pressure drop in surface closing pressures	psi	*PD*	P_{drop}	*PD*	ΔP_{io}
P_{g}	pressure of injection gas at surface—general	psig	*Pg*	P_{g}	P_{g}	—
P_{gd}	pressure of injection gas at D_w	psig	*Pgd*	P_{gd}	P_{gd}	p_{iod}
$P_{io(n)}$	injection operating pressure at surface to open n^{th} valve	psig	*Pio(n)*	$P_{io(n)}$	$P_{io(n)}$	$P_{io(n)}$
$P_{io(1)}$	injection operating pressure at surface to open Valve 1	psig	*Pio(1)*	$P_{io(1)}$	$P_{io(1)}$	$P_{io(1)}$
$P_{iod(n)}$	injection operating (or opening) pressure at n^{th} valve	psig	*Piod(n)*	$P_{iod(n)}$	$P_{iod(n)}$	$p_{ioD(n)}$
$P_{iod(1)}$	injection operating (or opening) pressure at Valve 1	psig	*Piod(1)*	$P_{iod(1)}$	$P_{iod(1)}$	$p_{iod(1)}$
P_{ko}	kickoff gas injection pressure at surface	psig	*Pko*	P_{ko}	P_{ko}	p_{ko}
P_{kod}	kickoff gas injection pressure at depth	psig	—	P_{kod}	P_{kod}	p_{kod}
$P_{pd(n)}$	flowing production pressure at n^{th} valve	psig	*Ppd(n)*	$P_{pd(n)}$	$P_{pd(n)}$	P_{pfDn}
$P_{pd(1)}$	flowing production pressure at Valve 1	psig	*Ppd(1)*	$P_{pd(1)}$	$P_{pd(1)}$	P_{pfD1}
P_{pvc}	production pressure valve closes	psig	—	—	—	—
$P_{sc(n)}$	surface closing gas injection pressure of n^{th} valve	psig	*Pvc(n)*	$P_{vc(n)}$	$P_{vc(n)}$	$p_{vc(n)}$
$P_{sc(1)}$	surface closing gas injection pressure of Valve 1	psig	*Pvc(1)*	$P_{vc(1)}$	$P_{vc(1)}$	$p_{vc(1)}$
P_{sep}	pressure of oil and gas separator	psig	*Psep*	P_{sep}	P_{sep}	—
P_{tro}	test rack opening pressure	psig	—	P_{tro}	—	—
$P_{tro(n)}$	test rack opening pressure—for n^{th} valve	psig	—	$P_{tro(n)}$	—	—

AVA Documents
Document Sharing Hub
Full document details: API RP 19GLHB-2020 (2023)

API 19GLHB	Description	Units	Formerly Expressed As			
			API Book 6	API 19G2	API 11V6	SPE
$P_{tro(1)}$	test rack opening pressure—for Valve 1	psig	—	$P_{tro(1)}$	—	—
P_{wf}	flowing bottomhole pressure at D_w	psig	*Pwf*	P_{wf}	P_{wf}	*Pwf*
P_{wh}	flowing pressure at the wellhead	psig	*Pwh*	*Pwh*	*Pwh*	*Pwh*
P_{ws}	static bottomhole formation or reservoir pressure	psig	*Pws*	*Pws*	*Pws*	*Pws*
P_1	pressure applied upstream under the bellows of a gas lift valve	psig	P_1	P_1	P_1	p_1
P_2	pressure applied downstream under the stem of a gas lift valve	psig	P_2	P_2	P_2	p_2
q_g	gas production rate, from formation, m = thousand	thousand scf/d, ft^3/sec	*qg*	q_g	q_g	q_g
q_{gi}	injection gas rate; m = thousand	thousand scf/d, ft^3/sec	*qgi*	q_{gi}	q_{gi}	q_{gi}
q_l	total liquid rate	BLPD, stbl/d	*ql*	q_l	*ql*	q_p
q_m	maximum liquid rate of well	BLPD	q_{max}	q_{max}	q_{max}	q_{max}
q_o	total oil production rate	BOPD, stbo/d, ft^3/sec	q_o	q_o	q_o	—
q_w	total water production rate	BWPD, stbw/d, ft^3/sec	q_w	q_w	q_w	—
R	ratio of gas lift valve port area to bellows area (A_p/A_b)	(ratio)	*Ap*/*Ab*	R	A_p/A_b	—
R_{gl}	ratio of gas to liquid	scf/bbl	*Rgl*	R_{gl}	R_{gl}	R
R_{gli}	ratio of injected gas to liquid	scf/bbl	*Rgli*	R_{gli}	R_{gli}	—
R_{go}	ratio of gas to oil	scf/bbl	*Rgo*	R_{go}	R_{go}	0
T_a	average gas injection temperature	°F	*Ta*	T_a	*Ta*	*"T–BAR"*
T_f	formation temperature	°F	*Tf*	T_f	T_f	*Tws*
T_s	static earth surface temperature	°F	*Ts*	T_s	T_s	—
T_{sc}	temperature at standard conditions	°F	*Tsc*	T_{sc}	T_{sc}	T_{sc}
$T_{v(n)}$	temperature at n^{th} valve	°F	*Tv(n)*	$T_{v(n)}$	$T_{v(n)}$	$T_{v(n)}$
$T_{v(1)}$	temperature at Valve 1 depth	°F	*Tv(1)*	$T_{v(1)}$	$T_{v(1)}$	$T_{v(1)}$

Documents
Document Sharing Hub
Full document details: API RP 19GLHB-2020 (2023)

API 19GLHB	Description	Units	Formerly Expressed As			
			API Book 6	API 19G2	API 11V6	SPE
T_{whf}	temperature at wellhead, flowing	°F	Twh	T_{whf}	T_{wh}	T_{wh}
v_g	volume of gas injected per cycle	scf	—	—	—	—
Z	gas compression deviation factor at average pressure and temperature	—	Z	Z	Z	z
γ_g	specific gravity of produced gas	—	SGg	S_g	SG_g	γ_g
γ_{gi}	specific gravity of injected gas	—	SGi	γ_{gi}	SG_i	γ_{gi}
γ_o	specific gravity of produced oil	—	SGo	γ_o	SG_O	γ_o
γ_w	specific gravity of produced water	—	SGw	γ_w	SG_w	γ_w

4 Introduction to Artificial Lift and Gas Lift

4.1 Basic Principles of Hydrocarbon Production

When hydrocarbons are identified in a reservoir, they are under pressure from the natural forces that surround and trap them. If a well (hole) is drilled into the reservoir, an opening is provided at a much lower pressure through which the reservoir fluids can flow. The driving force that causes these fluids to move out of the reservoir and into the wellbore comes from the natural compression of the fluids that are stored in the reservoir. The energy that causes a well to produce hydrocarbons is a result of a reduction in pressure between the reservoir and the producing facilities on the surface (Figure 4.1). If the pressures in the reservoir and the wellbore equalize because of a decrease in reservoir pressure or an increase in wellbore and surface pressure, then no flow from the reservoir occurs, and the production from the well ceases.

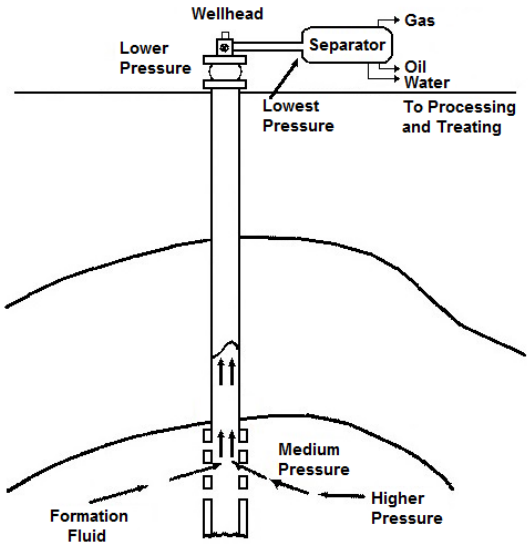


Figure 4.1—Production Process in an Oil or Gas Well

Documents
Document Sharing Hub
Full document details: API RP 19GLHB-2020 (2023)

Factors that affect the producing characteristics of a hydrocarbon well are interrelated and can include fluid properties of the hydrocarbon, amount of gas and water associated with the hydrocarbons, properties of the reservoir, size of the producing conduit, the related downhole equipment (mandrels and valves), and the size and length of the flowlines connecting the well to production facilities. These factors play a part in a well's performance and should be considered when the production installation is designed. An ideal installation makes maximum use of the natural energy available from the reservoir to ensure optimum hydrocarbon production.

4.2 Artificial Lift System Basics

In many wells, the natural energy associated with hydrocarbon reserves will not produce a sufficient pressure differential between the reservoir and the wellbore to cause the fluids to flow into the production facilities at the surface. In other wells, natural energy will not lift hydrocarbons to the surface in sufficient volume to be commercially viable. To achieve the desired production rates, the well's natural energy can be supplemented by a method typically referred to as artificial lift. Two basic methods of enhancing the production of a hydrocarbon well by artificial lift are

a) density reduction with gas lift systems, or

b) pumping systems (see Figure 4.2) as follows:

- systems with beam units reciprocating a sucker rod positive displacement pump,
- electric submersible motors driving a centrifugal pump,
- surface motors rotating rods to drive a progressive helix cavity pump,
- surface injection pumps providing hydraulic fluid to drive a subsurface jet or positive displacement pump.

The contents of this handbook focus on the various aspects of gas lift systems.

Documents
Document Sharing Hub
Full document details: API RP 19GLHB-2020 (2023)

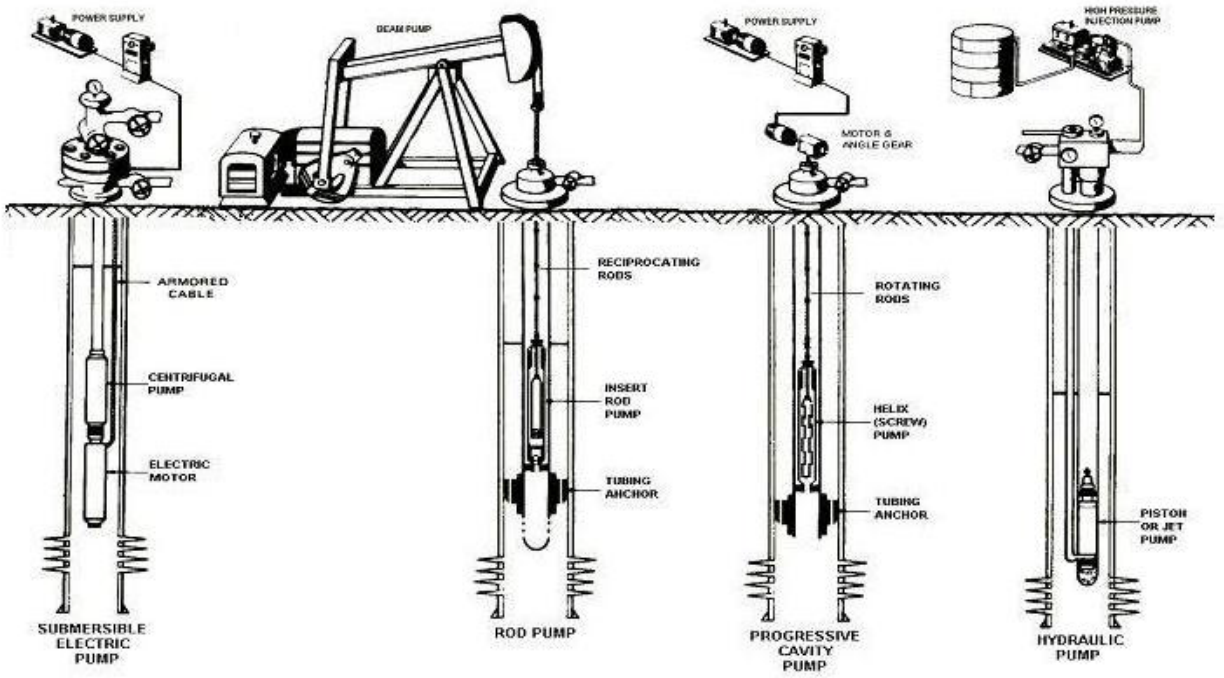


Figure 4.2—Artificial Lift with Pumps

4.3 The Process of Gas Lifting Liquids

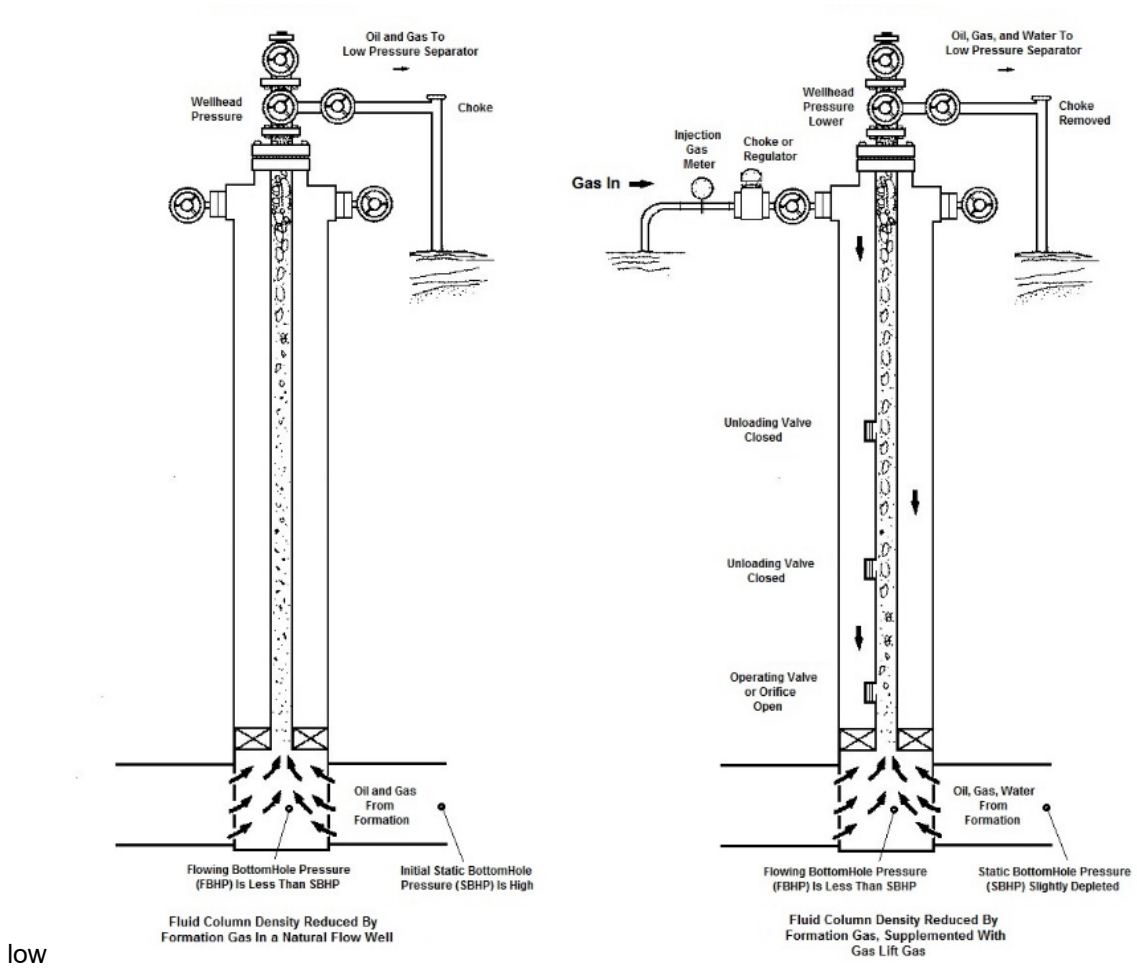
Gas lift is the form of artificial lift that closely represents the reservoir's natural flow process. In a natural flow well, as the fluid travels upward toward the surface, the fluid column pressure is reduced as the pressure falls below the bubble point and the free gas expands [see Figure 4.3 a)]. A gas lift system provides the means to inject lift gas into the conduit (typically the annulus) of a producing well at a depth that will effectively lighten the mixture density of the production fluid. This reduction in the fluid column density creates a greater pressure differential between the reservoir and the wellbore, thereby causing the well's flow to be initiated or increased. When a well produces water along with the hydrocarbon, the amount of lift gas required is increased because of the higher density of the water in the flowing fluid column. The same pressure differential between wellbore and reservoir can therefore be maintained [see Figure 4.3 b)].

4.4 Choosing an Artificial Lift System

The choice of an artificial lift system design for a given well or field requires thoughtful consideration. This gas lift handbook recognizes that electric submersible pumping, sucker rod beam pumping, progressing cavity pumping, and subsurface hydraulic pumping (Figure 4.3) serve a valuable portion of the artificial lift marketplace; however, the process of analysis of which is best for a particular well or field is outside of the scope of this handbook. Plunger lift (not illustrated herein) is included in artificial lift systems but does not reduce density nor pump fluid. The plunger is equivalent to a pig in a pipeline and is used to improve sweep of small volumes of liquid that accumulate and are produced intermittently.

The selection of a gas lift system for a particular well or field requires the availability of the necessary lift gas and the systems and personnel to control the injected gas. If the necessary volume of gas is available, either as dissolved gas in the produced hydrocarbons or from an outside source, then gas lift is often an ideal selection. Experience has shown that produced gas will support a gas lift system if the daily gas rate from the reservoir is at least 10 % of the total circulated gas rate. If an installation is adequately designed, wells can be gas lifted over a wide range of producing conditions by regulating the injection gas volume at the surface.

Documents
Document Sharing Hub
Full document details: API RP 19GLHB-2020 (2023)



low

a) Natural Flow Well **b) Gas Lift Well**

Figure 4.3—Production from Natural Flow and Gas Lift Wells

4.5 Gas Lift System Types

The two basic types of gas lift systems are continuous flow and intermittent flow. The choice of system type is based on the well and the gas distribution system conditions, producing rate, tubing diameter, static bottomhole pressure (SBHP), PI, gas piping diameter, gas injection pressure, and the available rate. Continuous flow is typically applied in early life when the pressure and rates are at the well's maximum, and intermittent lift is used in late life when rates and pressure are at the well's minimum. Water, gas, or sand influx can influence the selection of an artificial lift system and the type of gas lift. In wells with a sand production potential, steady, continuous flow is preferred since intermittent (pulsating) or surging flow tends to agitate sand particles and move them into the wellbore. Gas lift is also applied to gas wells for deliquification at kickoff.

Figure 4.4 shows both continuous and intermittent lift. The left illustration shows continuous injection of lift gas in sufficient amount to reduce density and to increase velocity for liquid entrainment or flow stability. The right and center illustrations show an intermittent well: the center panel has the controller open and injecting that causes the operating valve to be open, and the right panel shows the shut-in period that permits a formation fluid slug to build in the tubing prior to the next intermittent injection cycle.

Documents
Document Sharing Hub
Full document details: API RP 19GLHB-2020 (2023)

4.6 Continuous Gas Lift

The continuous gas lift system uses a steady rate of gas injected in the well tubing to lift the liquid from the reservoir. This constant injection of pressurized gas into a flowing column reduces the mixture density and increases mixture velocity, which can lower the FBHP, thus increasing the well's production.

Injection gas joins the formation gas to lift the fluid to the surface by one or more of the following processes:

a) reduction of fluid density and column weight;

b) expansion of the injection gas, so that it pushes the liquid ahead, reducing the column weight;

c) displacement of liquid slugs when the bubbles created by the gas provide a piston effect to move the fluid upward, all increasing the differential pressure between reservoir and wellbore.

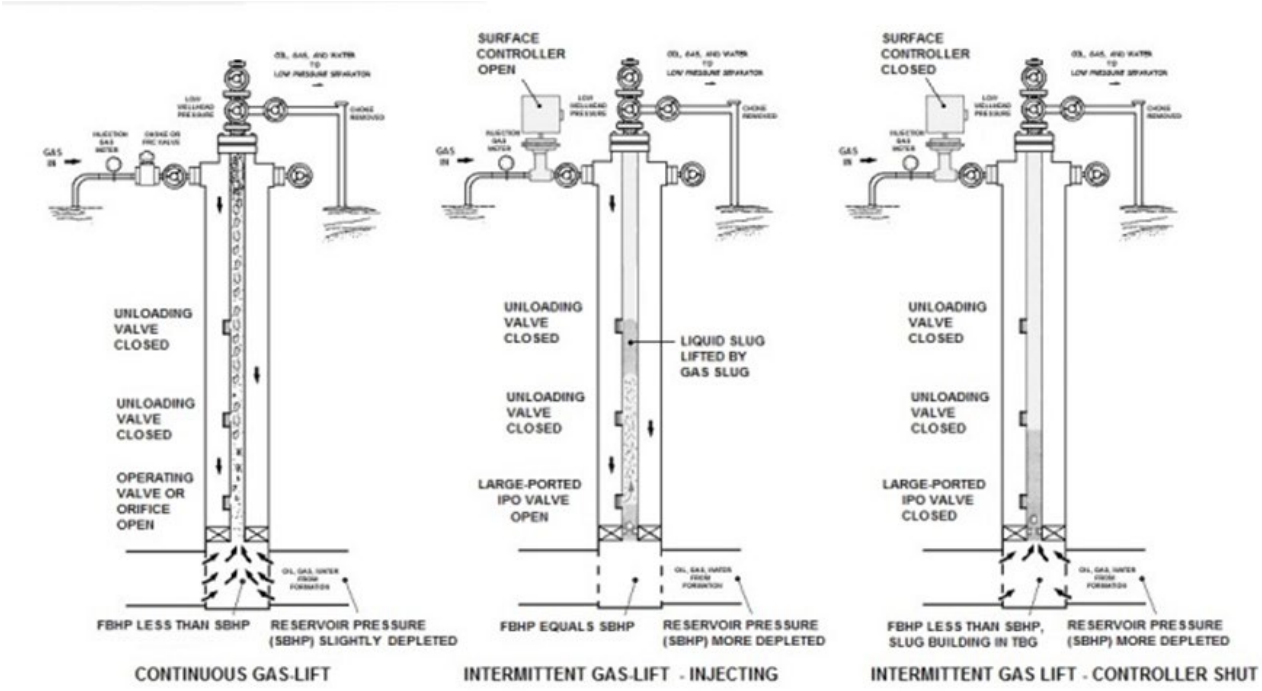


Figure 4.4—Continuous and Intermittent Gas Lift

Continuous gas lift is typically the best method for most wells, especially where FBHP pulsations need to be minimized due to sand movement or gas or water movement forming a cone at the wellbore.

With the well shut in and without gas injection, the wellhead pressure plus the static wellbore gas and liquid pressure gradients equal the SBHP, also called the average reservoir pressure, P_{ws}. When gas is injected into the tubing, the fluid gradient becomes lighter from the point of gas injection to the surface. The depth of gas injection should be at the deepest gas lift valve possible, within a set of constraints: available kickoff injection pressure, static fluid gradient and reservoir pressure, flow rate and flowing pressure gradient, and the mandrel spacing, which should accommodate the highest PI anticipated. This reduces the FBHP and creates the drawdown needed for a higher production rate. The static and gas lift gradients are illustrated in Figure 4.5.

Documents
Document Sharing Hub
Full document details: API RP 19GLHB-2020 (2023)

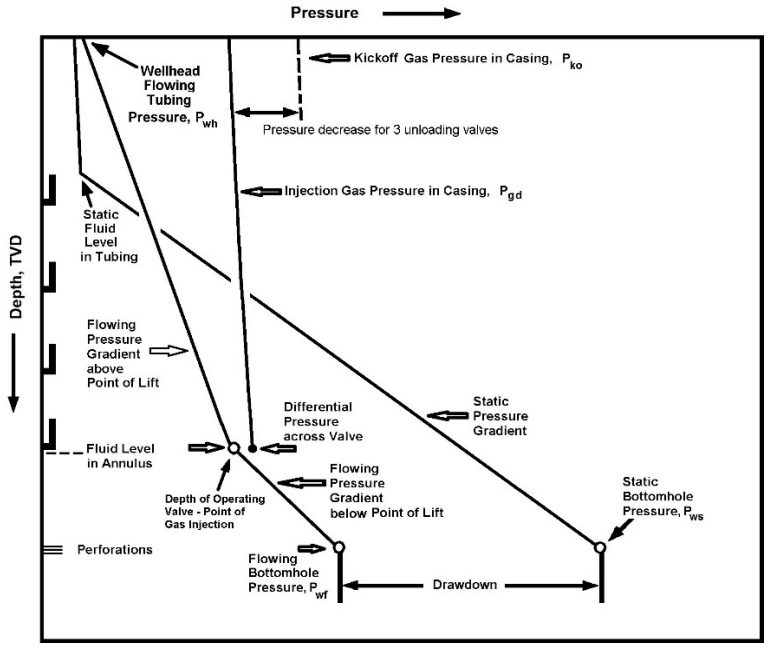


Figure 4.5—Static and Gas Lift Pressure Gradients in the Wellbore

The FBHP, also called the wellbore flowing pressure, P_{wf}, is a function of the flowing pressure gradient above the point of gas injection, formation fluid pressure gradient below the point of injection, and flowing wellhead back-pressure. To attain lift effectiveness at the lowest injection gas-liquid ratio (IGLR), the point of gas injection should be at the deepest valve. High distribution pipeline pressure and properly set unloading valves permit lift from the deepest set gas lift valve. If the deepest point is an orifice, the operating injection pressure can decline substantially if the PI and tubing pressure are low.

Continuous gas lift for liquid production can typically achieve a flowing gradient of approximately 0.10 psi/ft to 0.15 psi/ft. This limitation should be considered when applying the technique to wells with low SBHP. With low reservoir pressure or low PI, intermittent gas lift can be applied.

4.7 Intermittent Flow Gas Lift Systems

4.7.1 General

The intermittent gas lift system uses a periodic gas injection cycle to lift a well with a low reservoir pressure or a very low production rate. This type of system is designed to produce at the rate at which fluid enters the wellbore from the formation. Intermittent gas lift is used only when the flow rate, SBHP, or PI are too low for the use of an effective continuous gas lift system.

In an intermittent flow system, fluid accumulates in the tubing at the bottom of the well. Periodically, a volume of pressured gas is injected into the tubing very quickly underneath the column of liquid, and the liquid column is displaced up the tubing to the surface (produced). The frequency of gas injection is based on the time required for an appropriate volume of liquid to enter the tubing. The duration of the gas injection period will depend upon the time required to displace one slug of liquid to the surface.

Intermittent lift applies large amounts of gas for a short duration of time. The production cycle consists of a liquid slug followed by a gas slug, which is then followed by tail gas until the intermittent cycle is repeated. The large rate of gas and low rate of liquid causes the flowing gradient to be approximately 0.05 psi/ft, after the slugs have surfaced, thus this method is applicable to low SBHP wells. However, the lift effectiveness is diminished and more gas is required, in terms of injection standard cubic feet (scf) of lift gas per stock tank barrel (bbl) of liquid produced (IGLR). Intermittent lift typically incorporates IPO-type unloading gas lift valves, with a large ported pilot operating valve or a large ported IPO valve.

AVA Documents
Document Sharing Hub
Full document details: API RP 19GLHB-2020 (2023)

Intermittent gas lift is recommended for low production rate hydrocarbon wells; however, defining where continuous lift should end and intermittent lift should begin varies by local expert opinion. Important disadvantages of intermittent lift are the limited maximum production rate and its pulsating effect on the gas distribution piping, which can destabilize other wells in the field. The pulsating downhole pressure can increase sand production. Also, this method is not well suited for deep gas lift through small-diameter production tubing. Finally, an intermittent lift well gas slug can be difficult to process within a closed system leading to gas venting/flaring due to overpressure relief, and intermittent wells can adversely affect the performance of the continuous wells in the same field due to supply pressure fluctuations. Gas supply system technical improvements can mitigate these issues.

The intermittent gas lift production rate depends on the liquid slug volume that is lifted. Low reservoir pressure wells can use bottomhole chambers to reduce the back-pressure and to allow accumulation of a large slug size. Gas piping restrictions are greater constraints with intermittent lift. The choice of intermittent lift is often related to the tubing size, since continuous flow can be achievable within a reduced tubing diameter to increase the produced fluid's velocity.

4.7.2 Gas Lift with Plungers

Plungers may be used with intermittent gas lift systems to improve slug lift effectiveness or in wells whose fluid properties cause the gas to channel through the liquid column. This system design can also be used in low-rate gas wells that are aided with lift gas. The plunger traverses the length of the tubing string in a cyclic manner, providing an interface between the lifting gas and the produced liquid. The plunger sweeps more of the liquid film from the tubing wall, minimizing the liquid fallback. See Section 13 for additional information on intermittent flow gas lift.

4.8 Gas Lift for Gas Wells

Gas lift applied to gas well deliquification requires injection into the liquid accumulation at or below the perforations. Reservoir pressure must be high enough to cause flow to go from the formation to the wellbore to the surface facility. Deliquification requires a velocity increase to entrain liquid into the gas stream, thus gas well analysis should calculate the quantity of lift gas needed to supplement formation fluids to attain the required mixture velocity. The options for injecting lift gas into liquids at the perforation zone are shown in Figure 4.6 (from left to right): open-ended tubing, an extension tube hanging from the tubing below the packer, and an injection mandrel connected to the annular space via a tube through a dual packer. Each method can convey the gas into the liquid column to promote mixing and velocity increase.

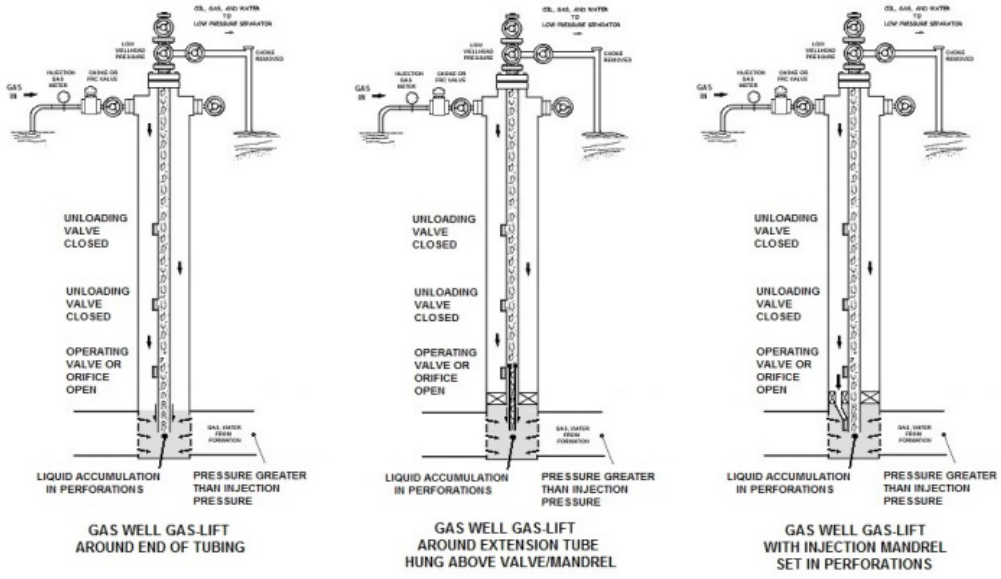


Figure 4.6—Gas Lift Methods to Remove Liquids from Gas Wells

Documents
Document Sharing Hub
Full document details: API RP 19GLHB-2020 (2023)

4.9 Major Components of a Typical Gas Lift System

4.9.1 General

The gas lift system is a flowing production process that utilizes gas compression/dehydration, or other high-pressure source, to distribute gas via thick-wall piping to wells, transport it downhole to valves/mandrels for injection into the tubing, and gather the multiphase flow mixture of formation fluid plus lift gas into the low-pressure separator vessels. Low-pressure gas is returned to compression to complete the closed cycle. After compression, the high-pressure reservoir gas is utilized and the lift gas is returned to the well(s).

The components of a gas lift system can be divided into three subgroups:

a) gas compression/dehydration, distribution system, measurement/control;

b) subsurface equipment (mandrel, valve, and latch assembly),

c) gas and liquid gathering and measurement system.

Figure 4.7 shows a generic gas lift system. High-pressure gas from compression is supplemented (or replaced) by gas well gas, and the combined stream goes into the triethylene glycol (TEG) absorber tower (also called contactor) that removes water vapor to dehydrate the gas. Dehydrated gas does not form icy plugs (hydrates) nor condense water, which corrodes the pipe. Gas distribution piping connects to each well and often includes volume chambers (or field scrubbers) to remove condensed hydrocarbon liquids and dampen gas surges caused by intermitting wells. Gas is delivered to each well through an orifice or sonic gas measurement instrument and a rate control device such as a manual or automated choke. Inside each well, gas flows down the tubing-casing annulus to the operating gas lift valve or orifice, enters the tubing to mix with reservoir fluids, and returns to the surface, while aerating the fluid column. The multiphase mixture of the reservoir fluid and lift gas returns to the low-pressure separator where liquids are sent to the treating process and gas returns to the compressor.

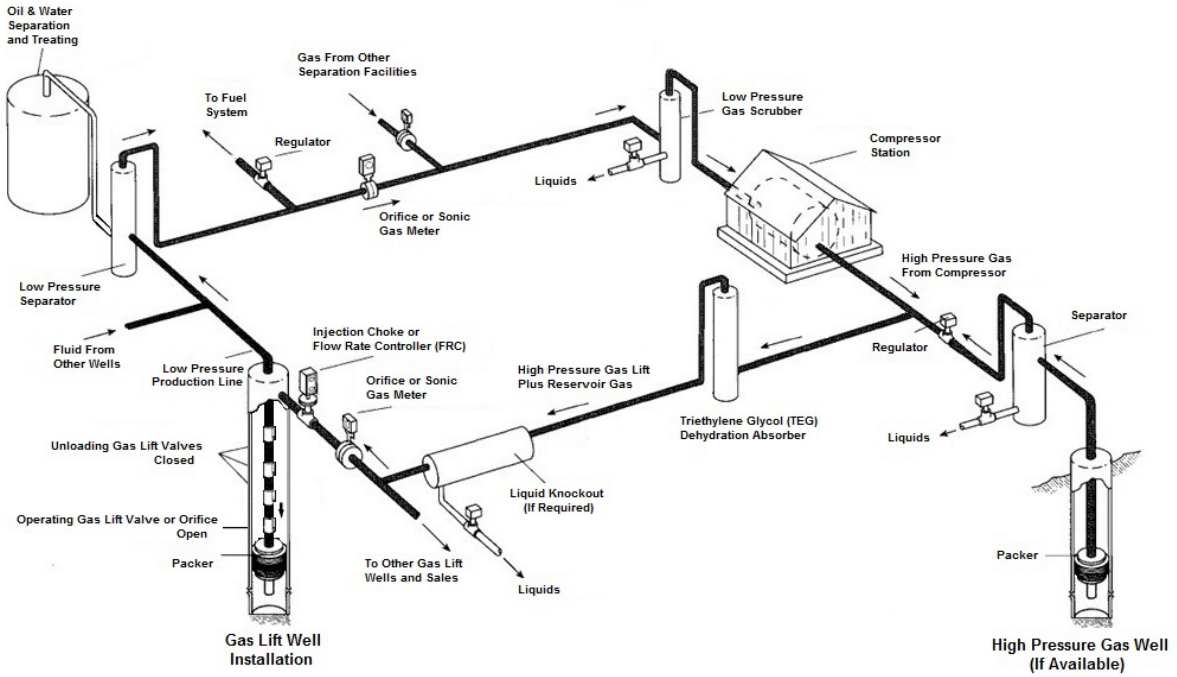


Figure 4.7—Gas Lift System, Supply Gas, Subsurface, and Fluid Gathering Components

AVA Documents Document Sharing Hub

Full document details: API RP 19GLHB-2020 (2023)

4.9.2 Gas Compression and Distribution System

A gas lift gas supply system is composed of a compression and dehydration plant, manifolds, gas lines, meters, and rate control devices. The compressor station receives gas from the low-pressure separator and gathering system, gas wells, or from the sales pipeline, and compresses it to a pressure suitable for gas lift operations. The compressor discharge pressure typically ranges from 800 psig to 2000 psig, although other pressures are used as needed, based on reservoir pressure, well PI, and gas lift valve constraints. Offshore wells on tension leg platforms or subsea installations often use very high pressures of 2000 psig or higher to minimize or eliminate unloading valves in the wellbores.

The amount of gas required depends on a number of criteria: number of wells and the depth of injection point; amount of hydrocarbon and water to be produced and the water fraction; amount of formation gas produced; and reservoir pressure. Compressor options are based on the required gas rate as follows:

a) small reciprocating units can compress a few million standard cubic feet per day—sufficient for a small field with a few wells;

b) large reciprocating units can compress from a few million to a hundred million standard cubic feet per day—for large onshore fields with numerous wells;

c) centrifugal compressors can compress from a few million to more than a hundred million standard cubic feet per day and are utilized for numerous wells in large hydrocarbon fields, especially offshore.

Dehydration options are typically TEG or dry bed mole sieve units. TEG removes sufficient water vapor to eliminate most hydrate and corrosion problems, but dry bed units can be used if the injection gas is exposed to extremely cold temperature.

The gas lift system uses the same surface facilities that process formation gas, since most fields require compression, dehydration, and treating to send the gas to sales, fuel for utilities, a natural gas liquids (NGLs) recovery plant, or to a re-injection plant. Lift gas is cycled in a closed loop that utilizes the existing facility but often requires added low-pressure compression capacity or high-pressure compression capacity to raise the gas pressure to that needed by the gas lift process.

Gas lift gas distribution pipelines connect the compression plant with the wells either directly or through field injection manifolds. The working pressure rating of the piping system should equal or exceed the maximum discharge pressure of the compressors. The diameter of the pipeline depends on the flow rate, the number of wells, and the length of the pipelines. The distribution piping pattern can have different forms:

— random, connecting from one well to another;

— a ring with individual well connections;

— major pipelines to field manifolds, with wells connected to the manifold; or

— a combination of methods.

Gas injection manifolds in the field can reduce the total installed pipe length and centralize operations such as gas flow measurement and control. The optimum number of manifolds will depend on the total surface area of the field and the number of wells. The number of wells per manifold can range from 2 to more than 30. Injection gas delivered to each well is measured and controlled to eliminate valve-damaging erosion during initial unloading and to optimize gas allocation during production.

4.9.3 Subsurface Equipment

Injection gas flows down the annulus or tubing to remove the control fluid through the upper unloading valves and reach a deeper operating valve or orifice (device that permits gas to flow into the tubing but cannot close).

AVA Documents
Document Sharing Hub
Full document details: API RP 19GLHB-2020 (2023)

When lifting from the bottom valve and in steady-state production, the measurement and control equipment provides a method to optimize the lift gas to each well within the field of wells.

The surface devices provide injection gas rate control and the gas lift valves function as pressure regulators. Figure 4.8 shows the subsurface equipment with gas lift valves and mandrels installed at different depths, a valve/mandrel option, and an IPO gas lift valve as follows.

a) Figure 4.8 a) wireline installed/retrieved valve set inside the pocket of a side-pocket mandrel in the tubing string is used when wireline work is preferable to workovers.

b) Figure 4.8 b) tubing-retrievable valve and mandrel requiring a workover for replacement.

c) Figure 4.8 c) gas lift valve schematic is a pressure regulator with pressure in the bellows (P_{bt}) to close the valve and casing gas pressure (P_{cd}) plus tubing fluid pressure (P_{pd}) to open it (back-check not shown).

Two steps for success with subsurface equipment are the initial step of unloading control fluid slowly to prevent valve erosion cutting with subsequent leakage and the second step of unloading valves closing in sequence, which permits injection from a deeper point of lift. The second step depends on the valve design procedures that are documented in subsequent sections.

When successful unloading occurs, injection gas at the bottom valve (or orifice) mixes with reservoir formation fluids and gives production delivery that is an interaction between reservoir inflow properties and multiphase outflow performance through the tubing and surface gathering network of pipes and separators.

4.9.4 Gas and Liquid Gathering Systems

The multiphase gas-liquid flow from the well is transported either directly or through a gathering manifold to a separator station. Pipeline (flowline) sizing is dependent on the connection method.

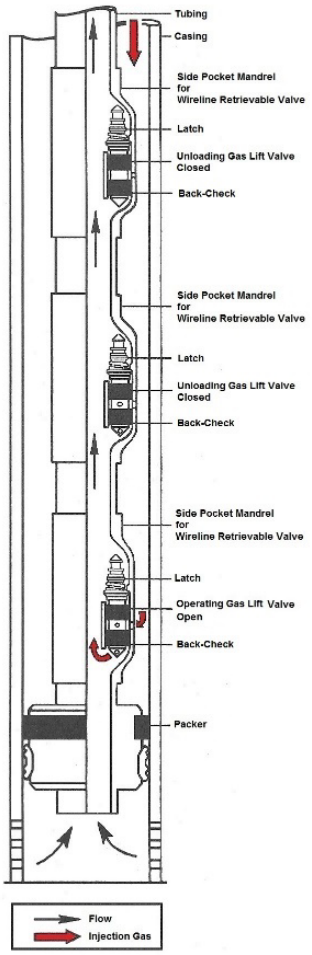
Directly connected flowlines—the diameter of the gas/hydrocarbon/water pipeline depends on the flow rate, topography, and distance traveled, and it is usually equal to or greater than the diameter of the production tubing. The modeling of production rate vs wellhead pressure for several flowline sizes aids in selecting an optimum size.

Manifold connected flowlines—in large fields where the wellheads are distant from the separation plant, gathering manifolds can minimize total pipeline length. The wellhead to manifold connection is sized as stated above. From the manifold, usually two flowlines connect with the flow station. One is the production pipeline, used to transport the commingled flow from all the wells (except for the one being tested), and is sized for total flow including future water increases plus lift gas. The other is a smaller-diameter test line and is used to connect only one of the wells to the test separator where its fluid and gas production is measured.

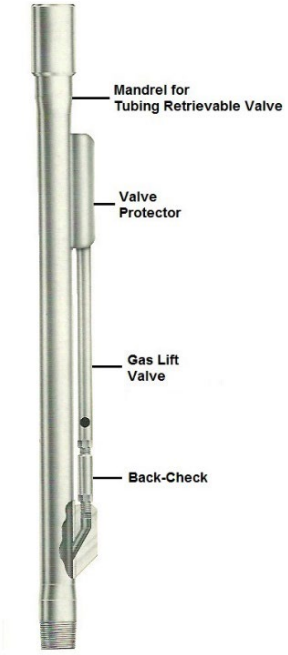
A test separator or multiphase meter located at the manifold is an option to avoid the need for the small test line and associated purging methods for long test lines. From the separator flow station, the low-pressure gas is returned to the compression plant to complete the cycle. For a production test to be representative of normal production conditions, the test separator should be configured to operate at the same pressure as the production separator. This allows the producing pressure to be the same whether the well is in test or in production.

Measurement of a well's fluids and of the group of well's fluids plus the injection gas metering is required for gas lift optimization. Unfortunately, production metering from a well is not precise since the production comes in surges, which reduces measurement accuracy. Thus, the optimization effort requires that a well be tested over a range of injection gas rates to obtain the "optimum" production rate. Orifice or sonic meters are used for gas measurement while turbine or Coriolis mass flow meters are used for liquid at production and test separators. Multiphase meters can be used in lieu of vessels and metering devices.

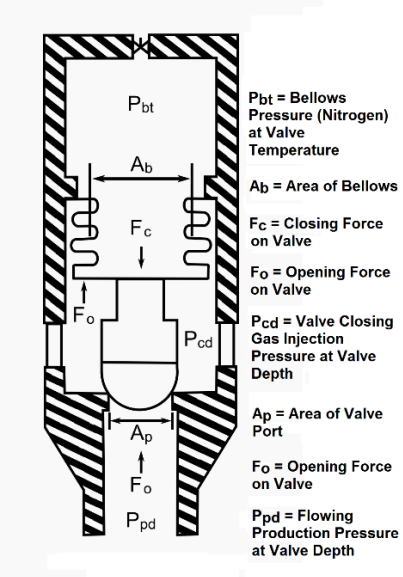
Documents
Document Sharing Hub
Full document details: API RP 19GLHB-2020 (2023)



a) Wireline Installed/Retrieved Valve



b) Tubing-retrievable Valve and Mandrel



c) Gas Lift Valve as a Pressure Regulator

Figure 4.8—Subsurface Equipment with Mandrels and Gas Lift Valves (IPO)

Documents
Document Sharing Hub
Full document details: API RP 19GLHB-2020 (2023)

4.9.5 System Component Operational Interactions

Each component interacts with the rest of the system in ways that considerably affect the required gas injection and the achievable hydrocarbon production. The key objectives of all components acting as a system are a deep injection of gas and a stable injection gas rate that lowers the FBHP and induces greater flow from the reservoir.

Gas compression and distribution shall provide a steady, constant pressure supply of dehydrated gas at an adequate rate for the wells in a field. The system characteristics include considerations of the following.

a) Low gas supply pressure causes the point of gas injection to be too shallow.

b) High gas pressure deepens the point of lift when the unloading valve pressures are appropriately set.

c) Gas rate, liquid rate, and the mixture density control the FBHP.

d) Injection gas rate shall be matched to the liquid rate and tubing size. Inadequate gas supply will reduce density insufficiently; the resulting low fluid velocity permits excessive liquid fallback, and excessive gas causes an increase in friction pressure loss.

e) Injection gas rate is adjusted with a surface choke or gas flow rate control valve.

f) Gas and liquid gathering components shall be properly sized to allow maximum production. Well production is limited by the imposed system back-pressure created from high separator pressure, a flowline with a small diameter, or a long flowline with a diameter too small for the distance.

g) Pipe sizing should be based on realistic flow rates. Excessively large diameter piping can cause severe slugging; too small of a diameter results in excessive friction loss.

h) Subsurface gas lift design is used to achieve the objective of reduced density and low FBHP with lift at a deep operating point.

i) Gas lift mandrel spacing enables the well to unload the kill fluid with the available injection pressure. Spacing shall be correct between valve mandrels or the unloading will stop prematurely and deep lift will not be attained.

IPO gas lift valve pressure settings are based on a specified gas injection surface closing pressure. This pressure permits the valve to close after unloading liquid from the annulus and transferring to the next deeper valve. Valve port size and gas/fluid pressures influence the gas flow throughput, but the surface choke (controller) has primary control. An IPO valve will react to the gas injection pressure. A PPO valve will react primarily to the production fluid pressure. The system can be operated with continuous injection into each well or with intermittent injection into some wells, provided the pulsing gas pressure does not adversely affect the continuous flow wells.

4.10 Advantages and Limitations of Gas Lift Systems

4.10.1 General

Gas lift is suitable for almost every type of well that requires artificial lift. It can be used to artificially lift hydrocarbon wells to depletion, regardless of the ultimate producing rate, to kick off wells that will flow naturally, to back flow water injection wells, and to deliquify gas wells. Because of its cyclic nature, intermittent flow gas lift is suited only to wells that produce at relatively low rates. Continuous flow gas lift will usually be more efficient for wells that produce at higher rates, where it can be maintained without the use of excessive injection gas.

Documents
Document Sharing Hub
Full document details: API RP 19GLHB-2020 (2023)

4.10.2 Advantages of Gas Lift Systems

The advantages of gas lift can be summarized as follows.

a) Downhole gas lift equipment requirement is less and operations are simple compared to other lift types.

b) Flexibility cannot be equaled by any other form of lift. Installations can be designed for lifting initially from near the surface and for lifting from near total depth at depletion. Gas lift installations can be designed to lift from few to many thousands of barrels per day.

c) Producing rate can be controlled at the surface by varying the injection gas rate.

d) Sand in the produced fluid does not affect gas lift equipment in most installations but can cause wireline problems when valves shall be pulled.

e) Gas lift is not adversely affected by deviation of the wellbore.

f) Relatively few moving parts in a gas lift system give it a long service life when compared to other forms of artificial lift.

g) Gas lift is ideally suited to supplement formation gas for the purpose of artificially lifting wells where moderate amounts of gas are present in the produced fluid.

h) Gas compressors, the major item of equipment, are required for natural flow or in a gas lift system and are easily inspected, repaired, and maintained. This equipment can be driven by internal combustion engines, gas turbines, or electric motors.

i) Gas lift systems typically allow through-tubing access for well servicing.

j) Gas lift systems are typically implemented where local gas compression is available.

4.10.3 Limitations of Gas Lift Systems

Gas lift systems have certain intrinsic limitations that are briefly summarized as follows.

a) Gas shall be locally available. In some instances, exhaust gases, CO_2, and nitrogen can be used, but these are more challenging to work with than natural gas.

b) Wide distances between wells can limit the use of a centrally located source of high-pressure gas. This limitation has been circumvented on some wells through the use of gas-cap gas as a lifting source and the return of the gas to the cap through injection wells.

c) Corrosive or hazardous lift gas can decrease the durability of gas lift equipment as it is necessary to treat or dry the gas before its use or require premium materials.

d) Installation of a gas lift system including compressors usually requires a longer lead time and greater preparation than single well pumping systems. In addition, the initial surface piping installation for gas lift will sometimes be more extensive than equivalent pumping installations.

e) In very low-pressured reservoirs, continuous flow gas lift cannot achieve the same pressure drawdown as some pumping systems. However, when low FBHP is desired, the use of intermittent lift and chamber lift forms of gas lift can usually achieve pressure drawdowns comparable to pumping systems.

f) Conversion of old wells to gas lift can require a higher level of casing integrity than would be required for pumping systems. However, high-pressure lift gas can be transported to a chemical-injection-type mandrel via coiled tubing or other instrumentation-type tubing strapped to the production tubing, thus protecting the casing from pressure.

AVA Documents
Document Sharing Hub
Full document details: API RP 19GLHB-2020 (2023)

4.11 Historical Review of Gas Lift System Developments

4.11.1 Early Experiments

Carl Immanuel Löscher [43] (German mining engineer) applied compressed air as a means of lifting liquid in laboratory experiments in 1797. The first practical application of air lift was in the mid-1800s when an American named Cockford lifted hydrocarbon from some wells in Pennsylvania. The first U.S. patent for gas lift equipment was for a technology called a “hydrocarbon ejector” was issued to A. Brear in 1865.

4.11.2 Chronological Developments

The chronological development of gas lift was compiled by Brown, Canalizo, and Robertson [27].

1) Prior to 1864: Some laboratory experiments were performed with minimal practical applications.

2) 1864 to 1900: This era consisted of lifting hydrocarbon producing wells utilizing compressed air injected through the annulus or tubing. Several flooded mine shafts were unloaded. Numerous patents were issued for foot pieces, etc.

3) 1900 to 1920: Gulf Coast Area “air for hire” boom. Such famous fields as Spindletop were produced by air-lift systems.

4) 1920 to 1929: The application of straight gas lift (no flow-control device) was applied with wide publicity from the Seminole Field in Oklahoma.

5) 1929 to 1945: This era included the patenting of approximately 25,000 designs of flow-controlling valves. More efficient rates of production as well as proration (restricted production) motivated the development of the flow valve.

6) 1945 to present: Since World War II, the pressure-operated valve has practically replaced all other types of gas lift valves. Also, in this era, many companies were formed to provide various designs of pressure-operated gas lift valves.

7) 1957 to 1980 and onward: Introduction of wireline-retrievable gas lift valve designs and the tubing-retrievable side-pocket mandrels designed to receive them. Also, the gas lift valve retaining latches and the kick-over tools necessary to install and retrieve these new valve designs were developed and patented.

8) 1980 to present: The evolution of gas lift equipment, practices, software programs, and control systems continues to be refined and efficiencies added. Surface-controlled valves using hydraulic or electric lines are available; high-pressure/high-temperature valves for subsea, extended reach tension leg platform, and other challenging wells are developed.

4.11.3 Technical Development of Gas Lift Equipment

The early technical development of gas lift equipment can be grouped into stages, as follows.

— Straight gas injection, which employed no valves and consisted primarily of U-tubing the gas around the bottom of the tubing.

— Jet collars were placed up the string to allow gas to enter higher up and thereby reduce the excessive kickoff pressures required for kicking around the bottom.

— Kickoff valves (forerunners to the valve designs of today) were next employed to provide a means for closing off gas after a lower valve was uncovered. The early kickoff valves were designed to operate on a 10 psi to 20 psi pressure differential until the development of the spring-loaded differential valve, which operated at approximately 100 psi differential.

AVA Documents
Document Sharing Hub
Full document details: API RP 19GLHB-2020 (2023)

4.12 Historical Development of Gas Lift Valve Designs

4.12.1 Differential Valves

Until 1940, the closest thing to the present-day gas lift flow valve were the differential valve designs, which were operated by the difference in pressure between the injection gas in the casing and the fluid in the tubing. The differential valve opened when there was an increase in fluid pressure relative to injection gas pressure and closed when the gas pressure increased relative to the fluid. This principle of operation meant that the differential valves had to be spaced close together to ensure proper operation of the installation. Little to no surface control was possible in a differential valve installation.

The specific gravity differential valve was very popular around 1940; its design utilized the difference in specific gravity between a 16 ft column of kerosene and a 16 ft column of well fluid for operating pressure. It was very successful in continuous flow wells; however, the valve's length and excessive diameter limited its applications.

4.12.2 Bellows-charged Valves

In 1940, W.R. King [41] introduced the bellows-charged gas lift valve (Figure 4.9). King's valve design, which is very similar to most present-day unbalanced, single-element bellows-charged gas lift valves, allowed for gas lifting of low-pressure wells with a controlled change in the surface injection gas pressure. Since King's valve was opened by an increase in injection gas pressure and closed by a decrease in pressure, the valve can be operated from the surface by changes in the injection gas pressure. This meant that it was no longer necessary to operate a valve from the surface by rotating or moving the tubing or wireline connected to the surface. The principal of operation of the bellows valve was far superior to the differential valve and fewer were required for each installation. Since the valve relied on the relatively high injection gas pressure for operation, the spacing between valves was much greater than that of the differential-pressure-operated valves.

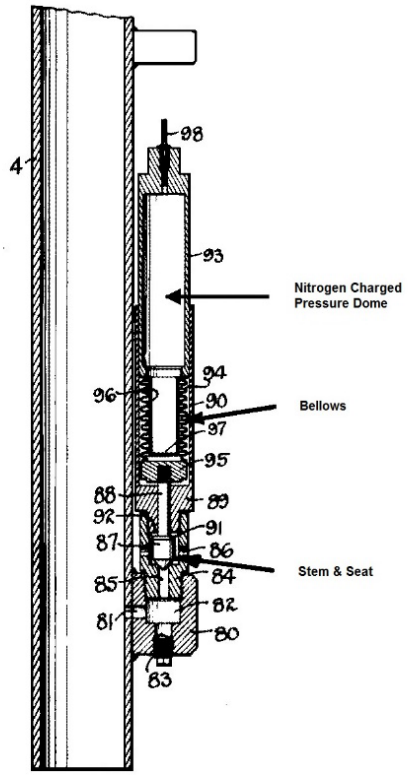


Figure 4.9—King Gas Lift Valve (IPO)

Documents
Document Sharing Hub
Full document details: API RP 19GLHB-2020 (2023)

King had good insight into valve construction when he designed his valve. He recognized the need for complete bellows protection, including an anti-chatter orifice mechanism. The bellows is protected from excessive well pressure by sealing the bellows chamber from the well fluids after full stem travel. Similar construction designs continue to be used by modern gas lift valves. See Section 10 on gas lift valves for further technical details.

4.13 Section Summary

The technology of gas lift systems has continuously improved, leading to its acceptance as a proven effective method of artificial lift. Core to this process are the dedicated and innovative professionals who pushed gas lift technology forward and documented those achievements for the good of the industry. Some of the notable contributors include Jack Blann, Kermit Brown, Joe Clegg, Ed DeMoss, Larry Johnson, Joe Mach, Zelimar Schmidt, Sid Smith Sr., and Herald Winkler, each significantly adding to the industry's knowledge and technology. This *Gas Lift Handbook* was compiled by David McCalvin, Coordinating Editor; John Martinez, Technical Editor; Mike Johnson, Workgroup Chair; Tony Hord, Craig Pennington, Ian Schuur, Greg Stephenson, and Reagan Wilkins, Workgroup Members; Wayne Mabry, Gas Lift Task Group 19 Chair; and Rochelle Hall, Tom Nations, and Burney Waring, special contributors.

This section presents the introduction to general practices and guidelines for gas lift installations. The information presented is further explained and discussed in the following sections. Like all evolving technologies, the content of this handbook is necessarily general, providing the background knowledge for those becoming familiar with the technology as well as providing a foundation of information to build upon. Several best practices and technical guidelines are provided within this text. Their use shall be applied with good engineering judgment and compliance with all applicable regulations.

5 Well Performance, System Designs, and Operations

5.1 General

Well performance is controlled by several interrelated factors in inflow and outflow performance. Flow from the reservoir into the wellbore is designated as inflow performance and flow up the production tubing and into the production facilities is designated as outflow performance. Inflow performance is controlled by reservoir pressure, productivity, and fluid composition. Outflow performance is a function of the size, type, and design of producing equipment and the fluid properties. Both inflow and outflow performance can be predicted with reasonable accuracy, and these predictions can be used in the design and sizing of well systems. Gas lift system designs require thoughtful consideration of technical and reservoir characterizations to ensure effective performance. This section discusses well performance prediction and deliverability methods and provides many of the necessary design considerations.

Performance predictions and system designs are often linked by testing results. Production testing is used to characterize potential reservoir capabilities by measurements of the flowing well's parameters. Well testing requires dedicated separators, wellbore gauges, and sample chambers to accurately define the flow behavior and fluid properties of the production and injection streams. The well testing measurements identify potential adjustments to each well and to the gas lift system, which are utilized to optimize the well's production. Based upon the testing results, well system design and computer performance prediction models are validated. These models provide data to improve control of the gas lift wells and to optimize the well performance for maximum oil production.

5.2 Well Performance (Inflow and Outflow)

5.2.1 General

Hydrocarbon production is classified into inflow and outflow performance. Inflow describes the flow of the produced fluids from the reservoir into the wellbore. Outflow describes the flow of the produced fluid from reservoir depth to the surface production facilities. Predictions of both inflow and outflow conditions are necessary for the design of an effective artificial lift installation. The well's inflow is typically expressed in terms of productivity. For the single-phase flow of liquids, the inflow is expressed as productivity index (PI, J, or Eq

AVA Documents
Document Sharing Hub
Full document details: API RP 19GLHB-2020 (2023)

two-phase flow (liquid and free gas), the production is not linear with pressure changes, thus an inflow performance relationship (IPR) curve results when plotting FBHP vs the production rate.

Inflow performance is measured by the number of barrels of liquid that a well is capable of producing at a given reservoir pressure less the FBHP at that rate, known as drawdown. These data are used to calculate the PI for that well. The inflow performance is the key factor in artificial lift design, but well deliverability is also linked to multiphase outflow performance of a well, which depends on a number of interrelated factors.

An applicable multiphase flow correlation is essential to establish quantifiable well performance capability where the well produces hydrocarbon liquids, water, and gas. Multiphase flow correlation software is commercially available, and there are also proprietary systems. The correlation methodology selected should have a proven track record of providing justifiable answers for the existing well, field conditions, or both. Multiple flowing pressure gradient surveys with consistent results should be used to validate the correlation's answers.

Multiphase flow correlations are used to predict outflow-pressure for specific well conditions, such as tubing/flowline diameter and deviation, to evaluate various rates and gas-liquid ratios. Tubing performance outflow-pressure curves can be generated and plotted on the IPR graph to find the anticipated flow rate for the specified conditions. Outflow performance curves for a range of potential operating conditions or pipe sizes can be helpful in gas lift system design evaluations. Current practices have evolved to the utilization of computer programs to define the flow correlations.

5.2.2 Inflow

5.2.2.1 General

The inflow performance model predicts the volume of hydrocarbon production as a function of static and FBHPs, or drawdown. The inflow model is dependent on the producing zone's reservoir pressure, bubble point pressure, permeability, thickness, skin (indicator of near wellbore damage), and logarithmic ratio of drainage radius to wellbore radius.

Measured flowing pressures, static pressures, and a production well test are used to validate a reservoir inflow model. One technique for monitoring well performance and the quality of well data is to analyze a well's inflow performance over time. Another technique is to plot a well's measured FBHPs against the production rate, comparing it with the theoretical inflow performance and calculated multiphase outflow rate. Two theoretical models in common usage are the Darcy (PI) model for single-phase flow and the Vogel (IPR) model for multiphase flow in the reservoir.

5.2.2.2 Darcy Productivity Index (PI = J) Technique

The definition of productivity index (PI) used in artificial lift is the number of barrels of liquid produced per day (BLPD) for each pound per square inch (psi) of reservoir pressure drawdown. Drawdown is defined as the difference between the SBHP and the FBHP. This can be written as an equation:

$$q_{\mathrm{l}} = J \times (P_{\mathrm{ws}} - P_{\mathrm{wf}}) \tag{1}$$

where

J is the PI, in BLPD/psi;

q_{l} is the liquid production rate, in BLPD;

P_{ws} is the SBHP, in psig;

P_{wf} is the FBHP, in psig.

Documents
Document Sharing Hub
Full document details: API RP 19GLHB-2020 (2023)

The PI is used in production because the measured data can be obtained during well testing. Rate, q_l, is from the test vessel or multiphase meter, and both static and flowing pressures at the perforations come from permanent downhole gauges or wireline gauges inserted at the time of the test.

The components in the PI are defined in the Darcy [30] Equation (2) for flow through the reservoir rock, and the symbols are illustrated in Figure 5.1. Permeability (k) and net height or thickness (h) are items that give high productivity, and skin (S) has the greatest detrimental effect.

$$q_l = \frac{0.00708\, k\, h}{\mu B\left(\ln\left(r_e / r_w\right) - 0.75 + S\right)} \times \left(P_{ws} - P_{wf}\right) \tag{2}$$

where

q_l is the production rate of liquid (oil plus water) in stb/d (measured data);

P_{ws} is the SBHP, in psig (measured data);

P_{wf} is the FBHP, in psig (measured data);

k is the permeability, in md (pressure buildup test);

h is the net height (thickness), in ft (log analysis);

μ is the reservoir fluid viscosity, in cp [pressure-volume-temperature (PVT) data];

B is the oil volume factor, in reservoir bbl/stb (PVT data);

r_e is the drainage radius, in ft (spacing estimate);

r_w is the wellbore radius, in ft (bit size or caliper);

S is the total skin, nondimensional (pressure buildup test).

The liquid viscosity can be calculated based on the following expression for both oil and water:

$$\left[\mu_o \times B_o\left(1 - W_C\right) + \mu_W \times B_W\left(W_C\right)\right] \tag{3}$$

where

μ_o is the reservoir oil viscosity, in cp (PVT data);

μ_w is the reservoir water viscosity, in cp (PVT data);

B_o is the oil volume factor, in reservoir bbl/stb (PVT data);

B_w is the water volume factor, in reservoir bbl/stb (PVT data);

W_c is the water cut fraction (water-liquid ratio) (measured data).

The term PVT is used to indicate pressure-volume-temperature data, which are typically based on subsurface samples obtained during exploration drilling representing each well interval.

Documents
Document Sharing Hub
Full document details: API RP 19GLHB-2020 (2023)

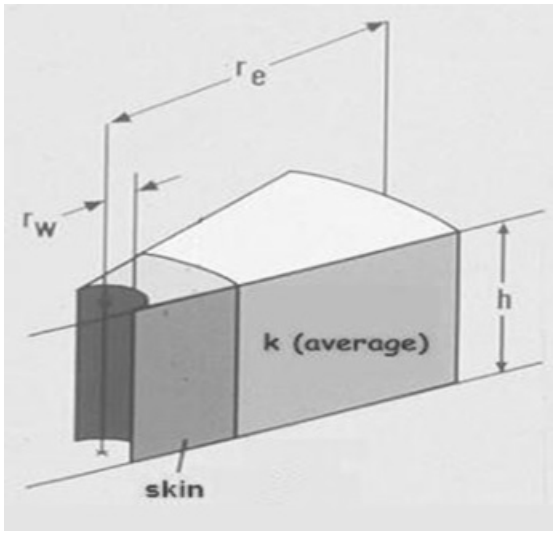


Figure 5.1—Reservoir Symbols for Darcy Equation

5.2.2.3 IPR Technique

5.2.2.3.1 General

The PI method assumes that all future production rate changes will be in the same proportion to the pressure drawdown as was the test case. This may not be true in a solution-gas drive reservoir producing below the bubble point pressure. The bubble point pressure is the condition of temperature and pressure where free gas first comes out of the solution in the oil. When the pressure in the formation drops below the bubble point pressure, gas is released in the reservoir and the resulting two-phase flow of hydrocarbons around the wellbore can cause a reduction in the well's productivity.

J.V. Vogel [55] developed an empirical technique called IPR after the terminology used in a paper written by W.E. Gilbert [37]. Vogel calculated IPR curves for wells producing from several fictitious solution gas drive reservoirs; however, a significant amount of experience has been obtained using the method in all two-phase flow conditions. Both the straight-line PI technique and the IPR curve require test data (rate, flowing and static pressure), and each can be used for determining the point of intersection of the inflow and outflow performance curves.

For existing wells, the IPR can be obtained from single-rate or multi-rate well test data. For wells not on production, analytical methods can predict the IPR by using the formation permeability and its thickness, expected drainage area, well radius, well/reservoir interface (skin), and the PVT of the reservoir fluids as shown in the Darcy equation. When producing from multiple layers or reservoir sections of variable productivity, divide the productive interval into segments and estimate individual IPRs depending on the segment characteristics, such as permeability thickness. If the well is producing from several reservoirs, every inflow zone can be modeled with a separate IPR. Changes in the reservoirs' pressures and temperatures due to depth differences, as well as changes in gas-liquid ratio and water cut, need to be reflected.

Dynamic simulators might require an IPR definition in which the key reservoir properties can change with time. The reservoir parameters are given as steady-state characteristics that are estimates of future well performance.

5.2.2.3.2 Vogel IPR Curve

Vogel [55] developed an empirical IPR model for two-phase (oil and gas) flow in solution-gas drive reservoirs. The work is based on reservoir simulation runs for many different PVT conditions. Vogel's work was based on oil flowing below its bubble point pressure, but the equation has been extrapolated for use with gross liquid

AVA Documents Document Sharing Hub
Full document details: API RP 19GLHB-2020 (2023)

flow. This curve takes the reservoir “skin” effect into consideration, but does not segregate that effect, which would require a pressure buildup test. The curve in Figure 5.2 can be generated using the following equation:

$$q_l / q_m = 1.0 - 0.2 \times (P_{wf} / P_{ws}) - 0.8 \times (P_{wf} / P_{ws})^2 \quad (4)$$

where

q_l is the stock tank rate of gross liquid per day (stb/d);

q_m is the maximum theoretical rate of gross liquid per day (stb/d) calculated from test data;

P_{ws} is the static reservoir pressure (psi) from measured data;

P_{wf} is the FBHP (psi) from measured data.

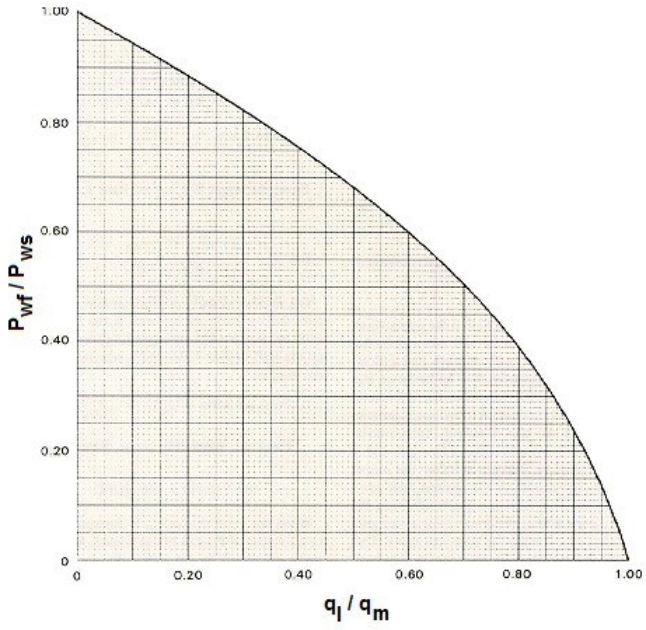


Figure 5.2—Vogel IPR Curve

The use of the dimensionless Vogel IPR curve allows one well test to define other potential producing conditions. Absolute pressure units shall be used since ratios are in the equation.

The curve procedure is as follows.

1) q_l is measured, and the ratio (P_{wf}/P_{ws}) can be calculated from the measured pressures acquired during testing.

2) From Vogel’s curve (Figure 4.2), (P_{wf}/P_{ws}) gives a corresponding ratio (q_l/q_m).

3) Since q_l is the test rate, $q_m = q_l/(q_l/q_m)$, where the ratio is from the curve.

4) With q_m calculated, any q_l gives (q_l/q_m), and the curve gives a corresponding (P_{wf}/P_{ws}).

5) $P_{wf} = P_{ws} \times (P_{wf}/P_{ws})$, P_{wf} at any q_l can be obtained.

Documents
Document Sharing Hub
Full document details: API RP 19GLHB-2020 (2023)

6) Also, any P_{wf} gives (P_{wf}/P_{ws}), and the curve gives a corresponding (q_l/q_m).

7) $q_l = q_m \times (q_l/q_m)$, q_l at any P_{wf} can be obtained.

The equation, instead of the curve, can be used with testing data, q_l, P_{wf}, and P_{ws}, to obtain a theoretical maximum rate, q_m.

$$q_m = \frac{q_l}{\left[1.0 - 0.2 \times (P_{wf}/P_{ws}) - 0.8 \times (P_{wf}/P_{ws})^2\right]} \quad (5)$$

With q_m calculated, the rate, q_l, or FBHP, P_{wf}, can be calculated for other conditions as shown in Equations (6) and (7).

$$q_l = q_m \times \left[1.0 - 0.2 \times (P_{wf}/P_{ws}) - 0.8 \times (P_{wf}/P_{ws})^2\right] \quad (6)$$

$$P_{wf} = 0.125 \times P_{ws} \times \left[-1 + (81 - 80 \times (q_l/q_m))^{0.5}\right] \quad (7)$$

To illustrate IPRs and how it applies to producing wells, two problems and two problem solutions are included. These are examples of real-world situations that have been utilized. They include the application of both the Vogel and Darcy technology. It is understood that these calculations are typically performed utilizing computer software; however, the actual calculations are shown for your reference and familiarization.

5.2.2.3.3 IPR Problem No. 1

Well A tested at total liquid rate of 3043 stb/d (oil plus water also written as barrels/day or barrels of liquid/day, but always stock tank barrels per day after shrinkage factor correction of the meter rate measured at a separator). While flowing the 3043 BLPD with a wireline pressure gauge at the perforations, the measured FBHP (P_{wf}) is 1696 psig. The well was shut in for a static reservoir pressure (P_{ws}) of 2000 psig.

a) From this test data, what is the PI, J (stb/d/psi), for this well?

b) If well production is increased to 3449 stb/d (BLPD), then what is the calculated FBHP (P_{wf}) using J?

c) Using J, what is the theoretical maximum rate, or absolute open flow potential, q_m, when P_{wf} = 0 psig (15 psia)?

5.2.2.3.4 IPR Problem No. 2

Well A data are used in the Vogel IPR method, q_l = 3043 BLPD, P_{wf} = 1711 psia, P_{ws} = 2015 psia (gauge pressure converted to absolute pressure). The objective is to compare Vogel results to the Darcy PI calculations.

a) What is the maximum rate, q_m, based on the Problem No. 1 test, q_l, P_{wf}, P_{ws}, and the Vogel equation [see Equation (5)].

$$q_m = \frac{q_l}{\left[1.0 - 0.2 \times (P_{wf}/P_{ws}) - 0.8 \times (P_{wf}/P_{ws})^2\right]}$$

If well production is increased to 3449 stb/d (BLPD), then what is the calculated FBHP (P_{wf}) using Vogel's equation [see Equation (7)].

$$P_{wf} = 0.125 \times P_{ws} \times \left[-1 + (81 - 80 \times (q_l/q_m))^{0.5}\right]$$

b) Compare the results from Darcy PI to Vogel IPR (compare answers in psia, psia = psig + 15).

AVA Documents Document Sharing Hub

Full document details: API RP 19GLHB-2020 (2023)

5.2.2.3.5 IPR Problem Solutions

Problem No. 1 Solution

a) From these test data, what is the productivity index, J (stb/d/psi), for this well?

$q_l = J \times (P_{ws} - P_{wf})$

$J = q_l/(P_{ws} - P_{wf})$ = 3043 BLPD/(2000 − 1696) psi

J = 10 BLPD/psi

b) If well production is increased to 3449 stb/d (BLPD), then what is the calculated FBHP (P_{wf}) using J?

$q_l = J \times (P_{ws} - P_{wf})$

$P_{wf} = P_{ws} - q_l/J$ = 2000 psig − 3449 BLPD/10 BLPD/psi

P_{wf} = 1655 psig (1670 psia)

c) Using J, what is the theoretical maximum rate, or absolute open flow potential, q_l, when P_{wf} = 0 psig?

$q_m = J \times (P_{ws} - P_{wf})$ = 10 BLPD/psi × (2000 − 0) psi

q_m = 20,000 BLPD

Problem No. 2 Solution

a) What is the maximum rate, q_m, based on the Problem No. 1 test, q_l, P_{wf}, P_{ws}, and the Vogel equation [see Equation (5)].

$$q_m = \frac{q_l}{\left[1.0 - 0.2 \times (P_{wf}/P_{ws}) - 0.8 \times (P_{wf}/P_{ws})^2\right]}$$

q_m = 3043 BLPD / [1 − 0.2 (1711/2015) − 0.8 (1711/2015) 2]

$$q_m = \frac{3043}{\left[1.0 - 0.2 \times (1711/2015) - 0.8 \times (1711/2015)^2\right]}$$

q_m = 12,011 BLPD

b) If well production is increased to 3449 stb/d (BLPD), then what is the calculated FBHP (P_{wf}) using Vogel's equation [see Equation (6)].

$$P_{wf} = 0.125 \times P_{ws} \times \left[-1 + \left(81 - 80 \times (q_l/q_m)\right)^{0.5}\right]$$

$$P_{wf} = 0.125 \times 2015 \times \left[-1 + \left(81 - 80 \times (3449/12,011)\right)^{0.5}\right]$$

P_{wf} = 1667 psia

Documents
Document Sharing Hub
Full document details: API RP 19GLHB-2020 (2023)

c) Darcy PI calculates P_{wf} = 1670 psia and Vogel IPR calculates P_{wf} = 1667 psia at q_l = 3449 BLPD, not significantly different at the production rate in the example.

M.J. Fetkovich [35] developed an empirical equation for two-phase flowing oil wells based on field measurements. He used the multiple well test data method that Rawlins and Schellhardt [48] had used for gas well deliverability. The Fetkovich equation is shown in Equation (8).

$$q_l = J' \times (P_{ws}^2 - P_{wf}^2)^n \quad (8)$$

where

q_l is the stock tank rate of gross liquid per day (stb/d);

P_{ws} is the static reservoir pressure (psi) from measured data;

P_{wf} is the FBHP (psi) from measured data;

J' is the back-pressure curve performance coefficient, obtained from test data per the method described in the Fetkovich paper;

n is the exponent of back-pressure curve, obtained from the slope of a log-log plot data.

The equation gives values of q_l that are less than the Vogel equation (for the same P_{wf}) and producing an IPR with more curvature.

Comparison of the three inflow equations shows that Darcy (PI) would predict the highest rate, Vogel predicts less, and Fetkovich would be the least, illustrated in Figure 5.3. Each requires one measured test data set (Fetkovich requires multi-rate testing unless n is assumed to be 1). Testing the well to define its capability is critically important and is used to select the applicable model. The figure shows the predicted rates from a well that tested at a PI = 10 bpd/psi is vastly different than one that tested at a PI = 1 bpd/psi. The difference between inflow equations is small, but the difference between wells' capability can be large.

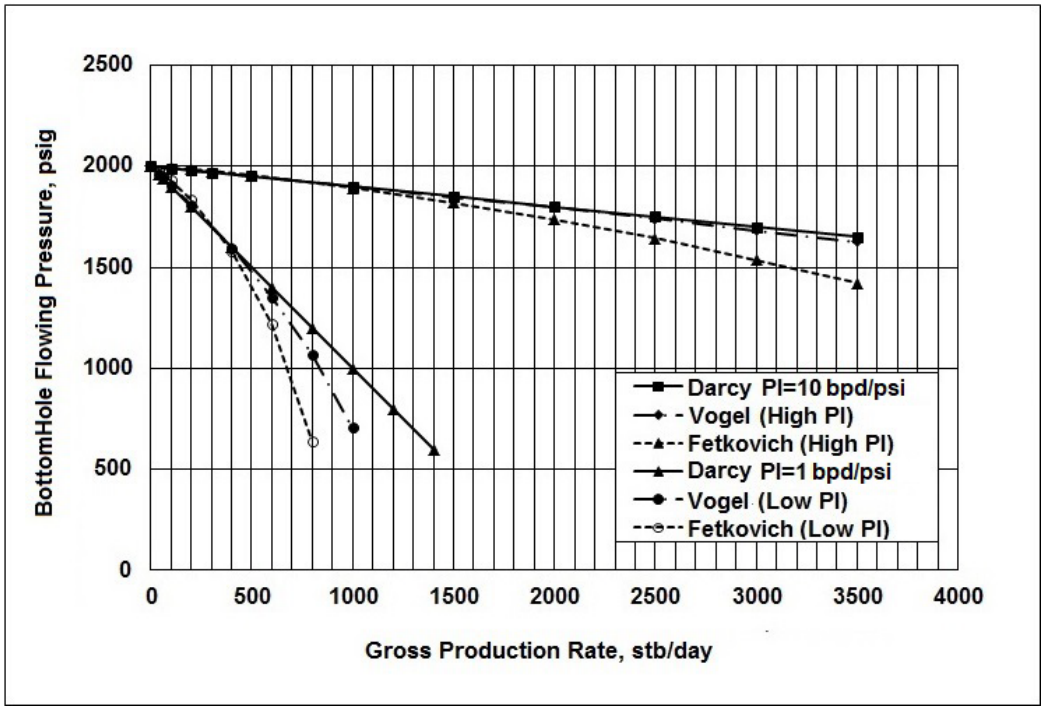


Figure 5.3—Reservoir Inflow Performance

Documents
Document Sharing Hub
Full document details: API RP 19GLHB-2020 (2023)

5.2.3 Outflow

Well outflow performance depends on complex factors, which include fluid characteristics, well configuration, conduit size, wellhead back-pressure, fluid velocity, and pipe roughness. Each factor can contribute significantly to outflow performance. However, the most important are fluid characteristics that affect density of the flowing mixture since the primary pressure drop is related to the elevation change from reservoir depth to the surface facility. The outflow model is dependent on PVT report data for the gas-oil ratio (GOR), API oil gravity, reservoir gas specific gravity, water specific gravity, and the completion tubing configuration and deviation. Similar to inflow model validations, an outflow multiphase model shall be calibrated to correlate with production and pressure testing results.

Multiphase flow correlations predict the pressure at depth in a flowing vertical column of multiphase fluid (oil-gas, oil-water-gas, or water-gas), taking into account the fluid characteristics, the conduit configuration, deviations, and other factors affecting the flow. Since the producing characteristics of continuous flow gas lift wells are essentially the same as those for a naturally flowing well, the flow correlations work equally well in either system.

Multiphase outflow curves are computer generated with dedicated software programs and define the pressures at the bottom of the wellbore based upon flow rates and the wellbore configuration. Multiphase outflow curves are plotted over the inflow curve, and if the curves intersect, then the natural flow rate, q_{nf}, is at the intersection point, shown as 400 stb/d in Figure 5.4 a). Note that another intersection occurs at 70 stb/d; however, it is ignored because the low velocity and declining slope cause this portion of the multiphase flow curve to be unstable and unreliable.

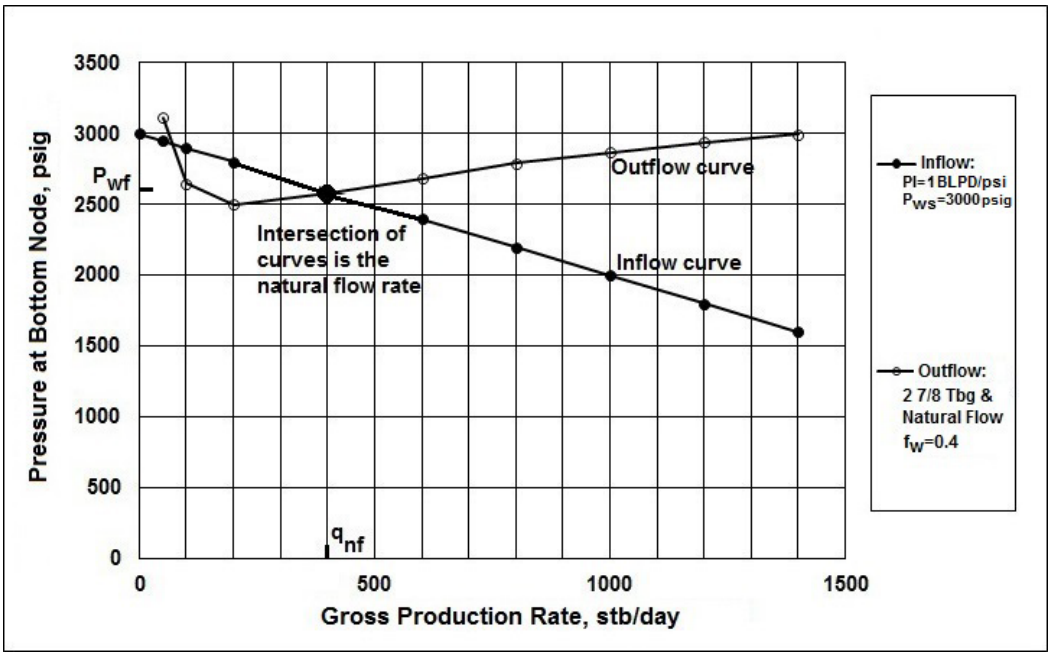


Figure 5.4 a)—Inflow-Outflow Performance—Natural Flow

If a flow rate exceeding that of the natural flow is desired, the outflow pressure required is greater than the inflow pressure and artificial lift shall be applied. The options include gas lift systems or pumping methods. Figure 5.4 b) illustrates pressures at pump intake (P_s) on the inflow curve and pump discharge (P_d) on the outflow curve if pumping is applied to achieve 1000 stb/d. Input energy drives the positive displacement, centrifugal, or jet pump, which raises pressure.

Gas lift gas can be used to reduce density and move the intersection point to 1000 stb/d when gas lift is applied [see Figure 5.4 c)]. The density reduction caused by the injected gas effectively reduces the pressure in the

AVA Documents Document Sharing Hub
Full document details: API RP 19GLHB-2020 (2023)