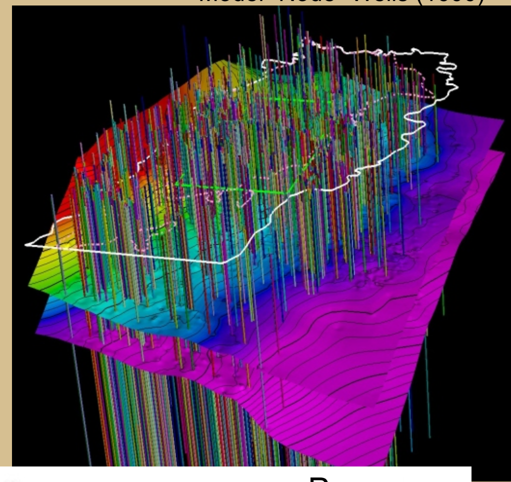
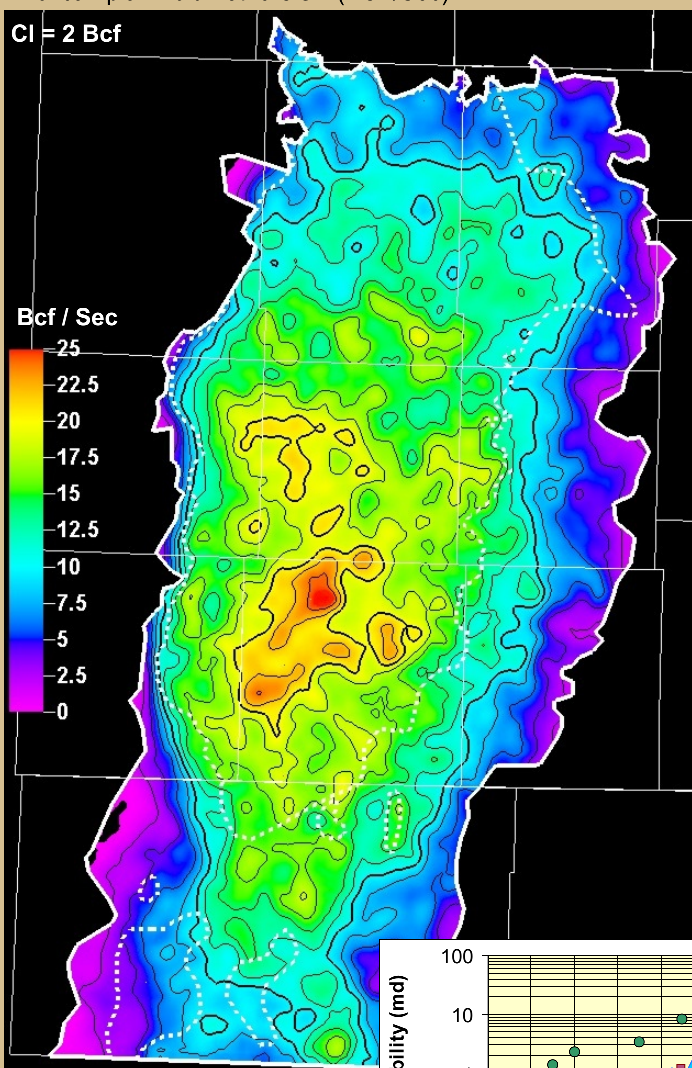
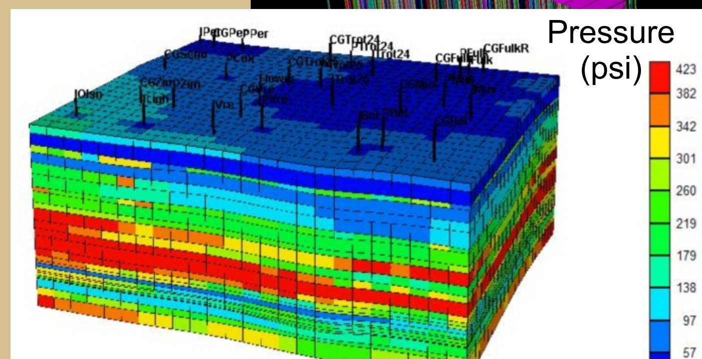
Hugoton Asset Management Project (HAMP)

Model "Node" Wells (1600)



Wolfcampian Volumetric OGIP(BCF/Sec)





Flower Simulation Model (2005)

Hugoton Geomodel Final Report

Martin K. Dubois
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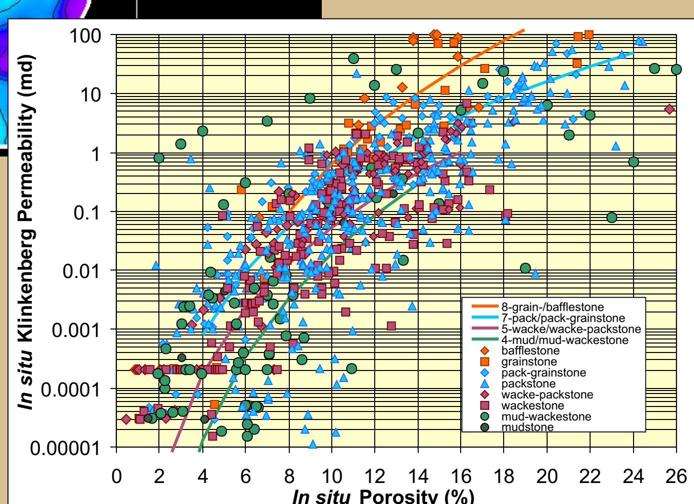
Robert E. Barba



Permeability-Porosity Trend by Lithofacies

Phylloid Algal Mound Facies

HUGOTON ASSET MANAGEMENT PROJECT (HAMP): HUGOTON GEOMODEL FINAL REPORT

Martin K. Dubois, Alan P. Byrnes, Saibal Bhattacharya, Geoffrey C. Bohling, John H. Doveton, and Robert E. Barba

DISCLAIMER

ACKNOWLEDGEMENTS

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INDUSTRY PARTICPANTS

Anadarko Petroleum Corporation
BP America Production Company
ConocoPhillips Company
Cimarex Energy Company
E.O.G. Resources Inc.
ExxonMobil Production Company
Medicine Bow Energy Corporation (now El Paso Exploration & Production)
Osborn Heirs Company
OXY USA, Inc.
Pioneer Natural Resources USA, Inc.

TECHNICAL GROUP

Successful completion of the Hugoton Asset Management Project and its multi-iteration model building strategy was possible only through close and ongoing integration of work by members of the multi-discipline technical group at the Kansas Geological Survey and consultants over a 2-1/2 year period.

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Appendices

Appendices provide supplemental information and data in an informal format.

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BatchCurveProcessing.xls

CHAPTER 1. INTRODUCTION

Martin K. Dubois and Alan P. Byrnes

The Hugoton and Panoma fields represent a major resource for the companies that own leases, royalty owners, and the state of Kansas. Although these fields have been producing for over 70 years there is much that is not fully understood about the nature of original and remaining gas-in-place, distribution of lithofacies, and the properties of the rocks that control reserves and production. To be able to efficiently manage the field at the lease- to field-scale an accurate static and dynamic model(s) of the fields was needed. This report is a result of a collaborative, multi-disciplinary study (Hugoton Asset Management Project (HAMP)) conducted by the Kansas Geological Survey and industry partners from 2004 through 2006. It follows a five-year study, the “Hugoton Project” (1998-2003) where the primary focus was on building a comprehensive geologic tops database. In the last few years of the Hugoton Project a cellular geomodel for the Council Grove (Panoma) in Kansas (Geomod1) was built in collaboration with Pioneer, where Shane Seals provided Petrel^{TM} modeling with the assistance of David Hamilton, SCM, Inc. Industry partners as well as KGS staff were encouraged by the results and the methods, and the workflow developed served as an initial template for the more ambitious HAMP models of the entire Permian gas system in Kansas and Oklahoma. The nine-industry partner HAMP, later expanded to ten (five from Hugoton plus five new participants), was begun in January 2004 as a two-year project. Building an accurate static model for the entire Hugoton field (Hugoton and Panoma in Kansas and Guymon-Hugoton in Oklahoma) became the primary objective in the Hugoton Asset Management Project (HAMP) with the goal of developing a model with sufficient detail to represent vertical and lateral heterogeneity at the well, multi-well, and field scale, that could be used as a tool for reservoir management.

Importance of the Hugoton field study extends beyond the borders of Kansas and Oklahoma. Both the knowledge gained and the techniques employed have implications for understanding and modeling reservoir systems worldwide that have similar geologic age, reservoir architecture, production characteristics, problems in determining water saturation, large data sets, multiple operators, or state of maturity. The full-field model of the 10,000-mi^2 (26,000-km^2) reservoir area provides a detailed three-dimensional view of thirteen shoaling-upward cycles vertically stacked in a low-relief shelf setting. The nature of the model and its construction provide a good analog for similar thin, stacked-cycle reservoir systems including the Aneth field in the Paradox basin (Weber et al., 1994; Grammer et al., 1996), fields in the prolific Permian basin of west Texas (Dutton et al., 2005), and the Khuff Formation in Gwahar and North fields in the Arabian Gulf (McGillivray and Husseini, 1992; Konnert et al., 2001). Fine-scale cellular models are particularly important for modeling thin-layered, differentially depleted reservoir systems, and methods used in building the model demonstrate the construction of a cellular petrophysical model for a giant field. The project also demonstrates the benefits of pooling proprietary geologic and engineering data in settings having multiple operators (Sorenson, 2005). As the world’s giant fields mature, high-resolution modeling at the full-field scale in data-rich environments will become increasingly important.

Approach

Building an accurate static model for the entire Hugoton field (Hugoton and Panoma in Kansas and Guymon-Hugoton in Oklahoma) was the primary objective in the Hugoton Asset Management Project (HAMP). The goal was to develop a model with sufficient detail to represent vertical and lateral heterogeneity at the well, multi-well, and field scale, which could be used as a tool for reservoir management including accurate prediction of remaining-gas-in-place. This required that the model be finely layered (169 layers, 3-foot (1 m) average thickness), and have relatively small XY cell dimensions (660x660 ft, 200x200m; 64 cells per mi^2). These criteria resulted in development of a 108-million cell model for the 10,000-mi^2 (26,000 km^2) area modeled. Although lithofacies geobodies tend to be laterally extensive, covering multi-section to township scales, small XY cell dimensions were required to allow the extraction of portions of the model for local reservoir simulation. Water saturations needed for original gas-in-place (OGIP) determination were estimated using capillary pressure methods and not measurements from induction wireline logs because accurate determination of water saturations using conventional wireline logs is complicated by deep mud filtrate invasion for typical drilling programs (Olson et al., 1997; George et al., 2004). Material balance methods for estimating OGIP are equally problematic because the reservoir is layered and differentially depleted and wellhead shut-in pressures (WHSIP) are strongly influenced by high-permeability interval properties, and do not accurately represent all interval pressures; and pressure data for individual layers are sparse. The Hugoton geomodel may be the largest model of its kind (lithofacies-controlled, property-based water saturations).

The general workflow for developing the Hugoton geomodel shown in Figure 1.1 can be characterized as comprising four principal steps: 1) Compile data for stratigraphy (formation tops) and core lithologic properties, petrophysical properties, wireline logs, fluid properties, and production and analyze data to certify that the data meet quality and accuracy criteria; 2) Define properties/develop algorithms including training a neural network and predicting lithofacies at node wells and developing wireline-log analysis algorithms (including corrections) and petrophysical properties algorithms (e.g., permeability-porosity (k-ϕ), capillary pressure (Pc), relative permeability(k_r)), 3) Develop databases of properties for use in geomodel construction including lithofacies, porosity, tops, free-water level at node wells, and 4) Develop geomodel by constructing 3-D cellular model using tops database, populating node-well cells with lithofacies and porosity database properties, upscaling properties as appropriate and populating 3-D model with basic properties, then utilizing petrophysical algorithms, populate 3-D cellular model with lithofacies-specific petrophysical properties and fluid saturations. Not illustrated in the static model workflow diagram, are reservoir simulations performed on upscaled portions of intermediate and final static models in different geologic settings. Simulations were performed concurrent with model building and served to validate the static model properties and model workflow. Chapters of this report summarize key aspects of the workflow as discussed below.

Background and Prior Work

The combined Kansas Hugoton and Panoma, Texas Hugoton and West Panhandle fields, and Oklahoma Guymon-Hugoton, with an estimated ultimate recovery of 75 tcf (2.1 trillion m^3) gas (Sorenson, 2005) represent the largest gas field in North America. Covering southwest Kansas and portions of the Oklahoma and Texas panhandles; these fields are situated in the Hugoton embayment of the Anadarko basin (Figure 1.2). Since discovery in 1922 and development in the 1950's, 35 trillion standard cubic ft gas (tcf, 963 billion m^3) have been produced from >12,000 wells over 6200 mi^2 (16,000 km^3) in the Kansas and Oklahoma portion of the Hugoton field (Figure 1.3). Unless otherwise noted, the term "Hugoton" in this report combines the Hugoton (Kansas), Panoma (Kansas and Oklahoma) and Guymon-Hugoton (Oklahoma) fields. Production is from the lower Permian Chase and Council Grove Groups (Figure 1.4) containing 13 stratigraphic intervals each comprising a wide range of lithofacies including continental and marine siltstones to sandstones, mudstone to grainstone limestones, fine- to medium-crystalline dolomites, and phylloid algal bafflestones (Figure 1.5). In most areas inside the Panoma field boundary, the gas column is continuous between the two stratigraphic intervals (Pippin, 1970; Parham and Campbell, 1993) and reaches a maximum thickness of 500 ft (150 m) in the west-central part of the study area. One exception may be in a relatively small portion of the field near the west margin in Morton County, Kansas, which is described by Olson et al. (1997) as being compartmentalized by faults. In Oklahoma, production outlined as "other Council Grove" (Figure 1.2) is from intervals in the Council Grove that are up to 300 ft (100 m) below the lowest perforations in the Chase. The reservoir is shallow, with depth to the top of the Chase ranging from 2100 to 2800 ft (640-850 m) and lower and upper productive limits, referenced to sea level, of approximately +100 ft (+30 m) on the east and +1250 ft (+380 m) on the western updip margin, respectively. Original wellhead shut-in pressure in Kansas was 437 psi (3013 kPa) (Hemsell, 1939), significantly less than half of a seawater pressure gradient, and similar, anomalously low initial pressures were recorded in Oklahoma (Sorenson, 2005). Average 72-hour wellhead shut-in pressure in Kansas in 2003 was 32 psi (221 kPa). Annual production in 2004 was 265 billion cubic ft (BCF, 7.5 billion m^3). Early completions in the Chase were commonly open hole or used a slotted liner followed by a large acid treatment. After 1960 typical completions commonly involve casing, perforating and acidizing as many as six zones separately, followed by a large hydraulic-sand-fracture treatment, sometimes exceeding 200,000 lb (91,000 kg) of sand, to the entire perforated interval (Hecker et al., 1995).

Although much has been published on the Hugoton over the 70-year life of the field, most of the studies have been broad in scope (Hemsell, 1939; Mason, 1968; Pippin, 1970). Sorenson's (2005) recent paper presents a paleostructural and pressure history for the reservoir system stretching from the Texas Panhandle to west-central Kansas and provides a good recent overview of the field history and prior work. Detailed studies involving reservoir characterization have been limited geographically and stratigraphically. For example, Siemers and Ahr (1990) investigated the Chase in the Oklahoma panhandle, Olson et al. (1997) studied the Kansas Chase, and Heyer (1999) focused on the Council Grove in a small area of the Oklahoma Panhandle. Following the

Kansas Corporation Commission proration order permitting a second well in each unit, several studies on reservoir characterization (Seimers and Ahr; 1990; Caldwell, 1991; Olson et al., 1997) and reservoir simulation (Fetkovitch et al., 1994; Oberst et al., 1994) were published. The work by Fetkovich et al. (1994) and Oberst et al. (1994) represent the only two reservoir simulations published to date, and neither included the Council Grove in their simulations. Past studies by industry have been generally confined to areas where they have assets and data. This report provides details of the most comprehensive reservoir characterization and simulation effort to date, both geographically (entire field) and stratigraphically (the entire reservoir system, Chase and Council Grove Groups).

Report Organization

Figure 1.1 illustrates the general workflow process involved in construction of the Hugoton geomodel. This report is generally organized to cover key aspects of tasks and products involved in the workflow. We have attempted to write each chapter in a manner that it can stand alone, but in some cases the reader will be referred to other chapters or the subject is best understood in context of other chapters or the entire body of the report.

Chapter 1. Introduction

A general overview of the project and this report, including some historical context, purpose of the study, problems, and approach is provided. Also covered is the importance of the field-wide geomodel as an example for similar layered reservoir systems worldwide. Earlier work by numerous authors is given a brief, but comprehensive review.

Chapter 2. Geologic Setting

This chapter discusses the regional geologic and tectonic history of the Hugoton Embayment of the Anadarko basin with emphasis on the large-scale geometry and sedimentation pattern on the low-relief Hugoton shelf. A general description by prior authors of the “giant stratigraphic trap” is also provided.

Chapter 3. Depositional Model

More detailed context for deposition of the 13 marine-continental, carbonate-siliciclastic cycles that compose the Hugoton reservoir system is developed, including evidence supporting a 1 ft/mi slope and a maximum of 100 ft of relief on the shelf. The influence of climate, shelf geometry, glacially forced sea level oscillation and their changes through Wolfcampian (icehouse towards greenhouse conditions) on lithofacies stacking patterns, lithofacies distribution patterns, and depositional models is presented.

Chapter 4. Reservoir Characterization

This chapter covers the models/equations used in geomodel development including the digital lithofacies classification system, petrophysical properties equations (e.g., routine and *in situ* properties, lithofacies-specific permeability-porosity relations, capillary pressure relations, and relative permeability relations), and wireline porosity-log analysis.

Chapter 5. Technology to Manage Large Digital Datasets

This chapter describes data management and the automated analysis tools developed to handle the large databases used for lithofacies-prediction and computation of porosities corrected for mineralogical variations between lithofacies and for washouts. Tools facilitated the efficient handling of large data volumes, and the ability to perform the multiple iterations required to test preliminary and intermediate algorithms and solutions.

Chapter 6. Static Reservoir Model

Building an accurate static model for the entire Hugoton field was the primary objective in the study. This chapter discusses the overall workflow, and provides details on the construction of the lithofacies, porosity, and petrophysical models not covered in other chapters (e.g., lithofacies prediction using neural networks, lithofacies and porosity variogram analysis, and permeability upscaling). The resulting lithofacies model is examined in detail.

Chapter 7. Water Saturations and Free Water Level

Due to frequent deep filtrate invasion during drilling water saturations estimated from wireline logs are problematic. Aspects of water saturation determination including the capillary-pressure properties of Hugoton rocks, the relationship between saturation and free water level, the FWL surface geometry, and sensitivity of the estimated water saturations and original-gas-in-place (OGIP) to capillary-pressure and FWL uncertainty are discussed.

Chapter 8. Reservoir Communication

This chapter analyzes the relative contribution of lithofacies/beds within defined productive intervals and the nature of communication between intervals. It further examines the potential and evidence for communication between intervals (formation/member) and groups (Chase/Council Grove) by natural causes and hydraulic fracture stimulations.

Chapter 9. Reservoir Simulation

Successfully matching pressure and production history at the well scale was an effective and important method for testing the validity of the static model(s) constructed. This chapter reviews the four simulation studies conducted, one single-well and three multi-well simulations, covering areas as large as 12-mi^2 and including up to 38 wells. Model inputs, pressure and production histories, model properties, and adjustments required of the model to acquire a match are documented through the entire simulation process in each case study.

Chapter 10. Original and Remaining Gas in Place

A volumetric model of original-gas-in-place (OGIP) at the well- to field- scale is an outcome of the Hugoton cellular geomodel and one of the main products sought by HAMP. Model OGIP is compared with cumulative gas produced at varying scales and validates the static model and free-water-level elevation for most areas. Pore volumes (PV), hydrocarbon-pore volume (HCPV), and ratio of HCPV/PV by lithofacies illustrate the relative contribution by the 11 lithofacies. Remaining GIP by zone is examined through analysis of simulation results and is discussed qualitatively with respect to the field static model.

Chapter 11. Conclusions

In the final chapter we provide a comprehensive review that includes key findings, a detailed summary of the processes involved in building the model, discuss specific findings at the workflow component level, and suggest additional work that could improve the model and topics deserving further investigation.

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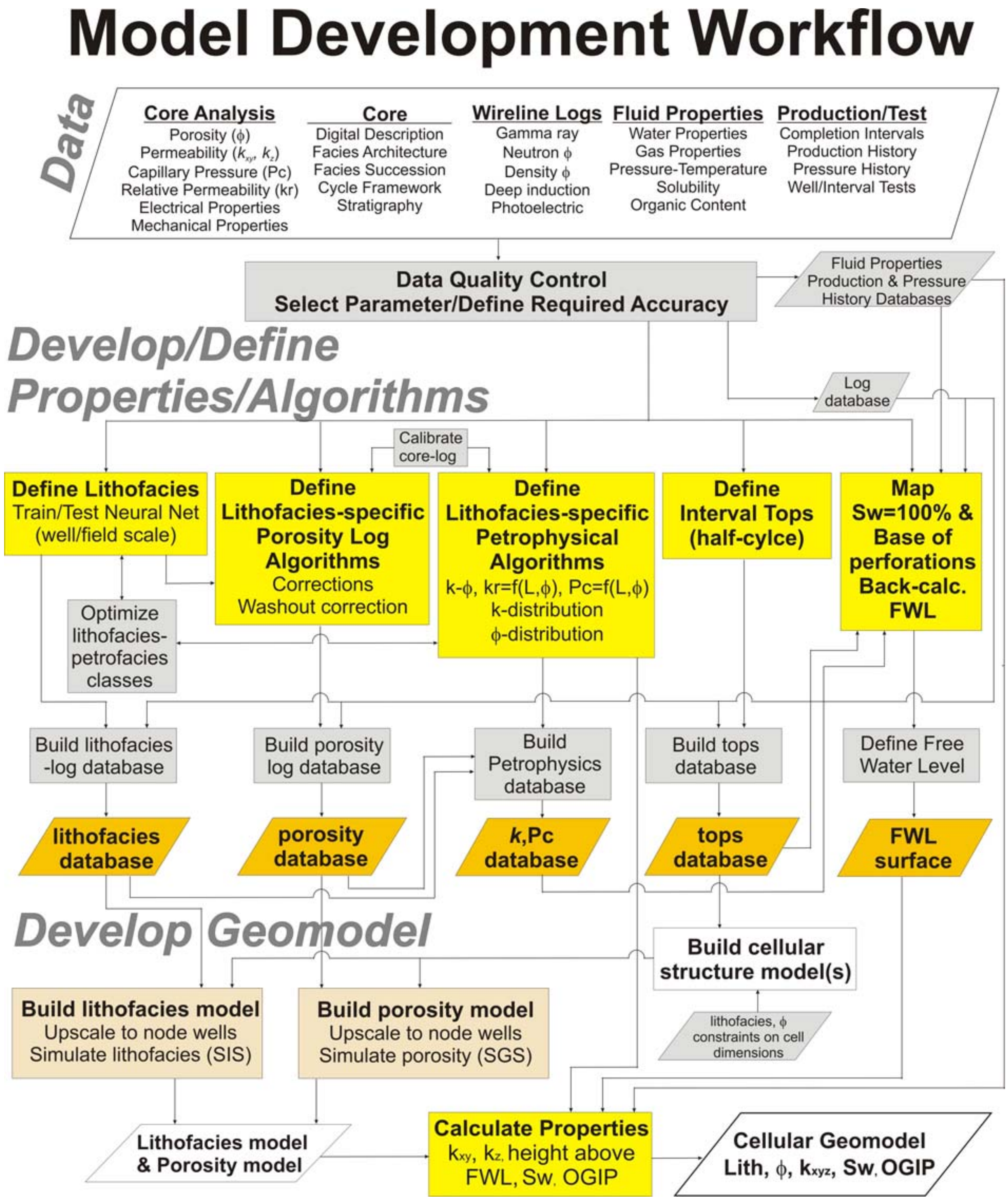

Figure 1.1. Workflow for field-scale Hugoton model. Workflow can be divided into three broad tasks: 1) gather and qualify data; 2) process data to provide basic geomodel input files (Develop/ Define/ Properties/ Algorithms); and 3) build the geomodel. The figure suggests the process is linear, while in reality, there are more feed back loops, multiple iterations at sub task level, and testing and validation at smaller scales.

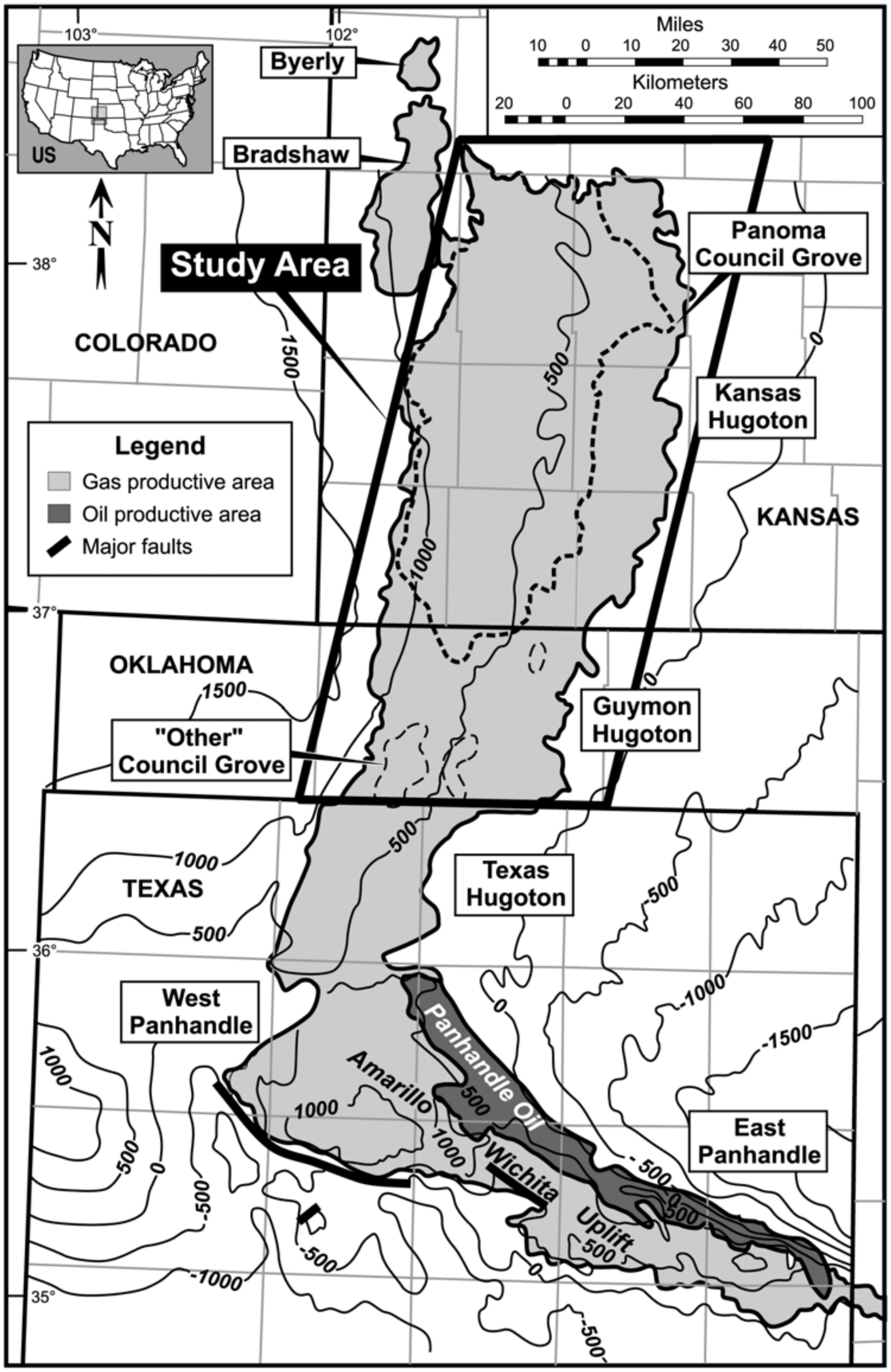

Figure 1.2. Regulatory boundaries for Permian (Wolfcampian) gas and oil fields, Kansas, Oklahoma, and Texas. Wolfcampian structure in feet, after Pippin (1970) and Sorenson (2005).

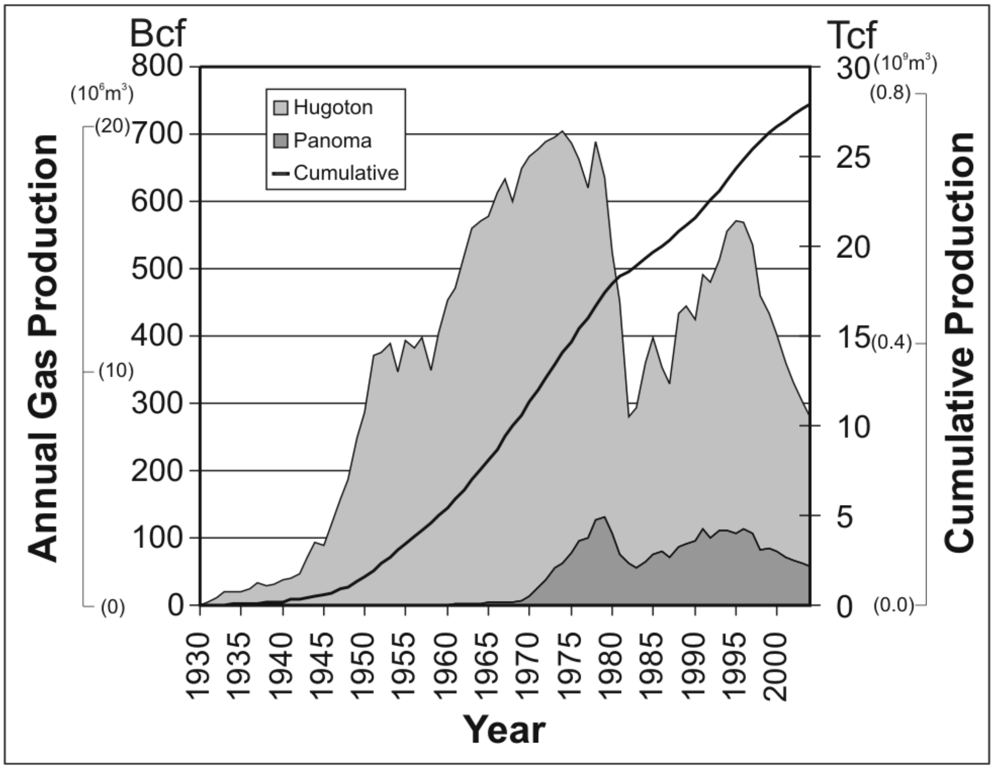

Figure 1.3. Gas production from the Wolfcampian (Hugoton and Panoma fields) in the Kansas portion of the study area through 2004. The Oklahoma portion of the study area produced 7 tcf (198 billion m^3) Wolfcampian gas in the same time period that 27 tcf (765 billion m^3) was produced in Kansas. The spike in production beginning in the early 1980's was due to infill drilling the Hugoton field in Kansas.

SYSTEM	SERIES	GROUP	Kansas fields	Oklahoma field
Permian	Leonardian	Sumner		
Permian	Wolfcampian	**Chase**	Hugoton-Panoma Byerly Bradshaw	Guymon-Hugoton
Permian	Wolfcampian	**Council Grove**	Hugoton-Panoma Byerly Bradshaw	Guymon-Hugoton
Pennsylvanian	Virgilian	Admire	Greenwood	
Pennsylvanian	Virgilian	Wabaunsee	Greenwood	
Pennsylvanian	Virgilian	Shawnee	Greenwood	

Figure 1.4. Stratigraphic column, Hugoton field area with the names of gas fields in Kansas and Oklahoma adjacent to the intervals from which they produce (compiled from Zeller, 1968; Pippin, 1970; Baars et al., 1994; Sawin et al., 2006). The combined Hugoton and Panoma fields in Kansas and the Guymon-Hugoton field in Oklahoma are lumped as "Hugoton" in this paper.

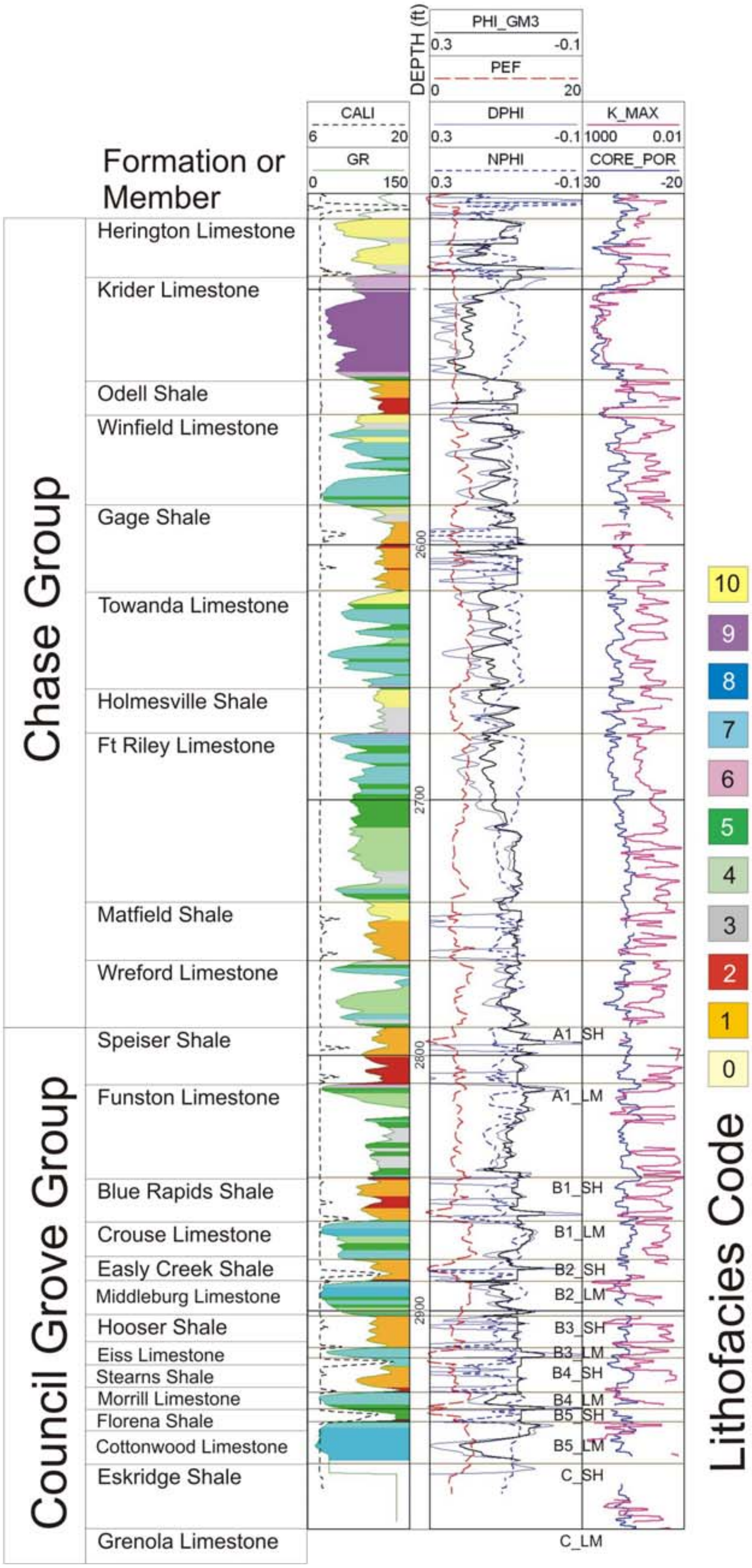

Figure 1.5. Formation- and member-level stratigraphy correlated to wireline well log in the Flower A-1 well, Stevens County, Kansas (after Dubois et al., *in press*). Commonly used formation/member letter-number combinations are shown for the Council Grove. Twelve of the 13 marine-continental (carbonate-siliciclastic) sedimentary cycles that are gas productive are shown (Grenola Limestone, C_LM is not logged). Stratigraphic names that include "Limestone" are marine half cycles when combined with an adjacent continental half-cycle, intervals with stratigraphic names that include "Shale," form a complete cycle. Color-coded lithofacies are derived from core. Three were deposited in a continental setting, L0- sandstone, L1- coarse siltstone, and L2- shaly siltstone, and eight in a marine environment, L3- siltstone, L4- carbonate mudstone, L5- wackestone, L6- very fine-crystalline dolomite, L7- packstone-grainstone, L8- phylloid algal bafflestone, L9- fine-medium crystalline moldic dolomite, and L10- sandstone. Wire-line-log abbreviations are caliper (CALI), gamma ray (GR), corrected porosity (PHI_GM3), photoelectric effect (PEF), density porosity (DPHI), neutron porosity (NPHI), core permeability (K_MAX, and core porosity (CORE_POR). Logged interval is 520 ft (160 m).