Fluvial architecture of the Burro Canyon Formation using unmanned aerial vehicle-based photogrammetry and outcrop-based modeling: Implications for reservoir performance, Escalante Canyon, southwestern Piceance Basin, Colorado

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Abstract

The Cretaceous Burro Canyon Formation in the southern Piceance Basin, Colorado, represents low sinuosity to sinuous braided fluvial deposits that consist of amalgamated channel complexes, amalgamated and isolated fluvial-bar channel fills, and floodplain deposits. Lithofacies primarily include granule-cobble conglomerates, conglomeratic sandstones, cross-stratified sandstones, upward-finining sandstones, and gray-green mudstones. To assess the effects of variable sandstone-body geometry and internal lithofacies and petrophysical heterogeneity on reservoir performance, conventional field methods are combined with unmanned aerial vehicle-based photogrammetry to create representative outcrop-based reservoir models. Outcrop reservoir models and fluid-flow simulations compare three reservoir scenarios of the Burro Canyon Formation based on stratigraphic variability, sandstone-body geometry, and lithofacies heterogeneity. Simulation results indicate that lithofacies variability can account for an almost 50% variation in breakthrough time (BTT). Internal channel-bounding surfaces reduce the BTT by 2%, volumetric sweep efficiency by 8%, and recovery efficiency by 10%. Three lateral grid resolutions and two permeability-upsampling methods for each reservoir scenario are explored in fluid-flow simulations to investigate how upscaling impacts reservoir performance. Our results indicate that coarsely resolved grids experience delayed breakthrough by as much as 40% and greater volumetric sweep efficiency by an average of 10%. Permeability models that are upscaled using a geometric mean preserve slightly higher values than those using a harmonic mean. For upscaling based on a geometric mean, BTTs are delayed by an average of 17% and the volumetric sweep efficiency is reduced by as much as 10%. Results of the study highlight the importance of properly incorporating stratigraphic details into 3D reservoir models and preserving those details through proper upscaling methods.

Introduction

Fluvial reservoirs are heterogeneous at different scales as related to the stratigraphic framework, architectural elements, and lithofacies. At the bedding and lithofacies scale, sedimentary structures have a significant control on porosity and permeability heterogeneity and associated fluid flow (e.g., Weber, 1982; Hurst and Rosvoll, 1991; Corbett and Jensen, 1993; Jackson et al., 2003). Fluvial lithofacies associations (architectural elements — different types of fluvial sandstone bodies) exhibit internal heterogeneity that impacts fluid flow (e.g., Fustic et al., 2011; Hubbard et al., 2011; Labrecque et al., 2011), and fluvial reservoir connectivity varies at the field scale because of the stratigraphic variability in sandstone-body stacking patterns (e.g., Willis, 2007; Pranter et al., 2009; Smith et al., 2009). Therefore, to create reservoir models that are representative in terms of storage and flow characteristics, it is essential to model the spatial distribution of permeability and other properties that are tied to the individual lithofacies, architectural elements, and the stratigraphy. Different scales of detail are critical; however, common practices of modeling fluvial reservoirs do not explicitly address all of these sedimentological details. Importantly, the significance of these fluvial stratigraphic features on secondary recovery has not been rigorously evaluated.

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using geologically constrained fluid-flow simulation models.

Deposits of the Cretaceous Burro Canyon Formation in the Piceance Basin, Colorado, were investigated using outcrop and subsurface data (core data). In the study area, the Burro Canyon Formation is overlain unconformably by the Cretaceous Dakota Formation and underlain unconformably by the Upper Jurassic Morrison Formation (Figure 1). The Cretaceous rocks outcrop in eastern and southeastern Utah and northwestern Colorado and have previously been interpreted as mainly braided to meandering river and floodplain deposits. However, details regarding the environment of deposition and the reservoir-scale sedimentology and stratigraphy are limited. Stokes (1952) identifies the age of the Burro Canyon Formation as Early Cretaceous in Utah and Colorado using fossil assemblages from outcrops.

Young (1960, 1973) studies the Dakota Group on the Colorado Plateau, which includes the Cedar Mountain (equivalent to the Burro Canyon Formation) and the Naturita Formation (now called the Dakota Formation). The study interpreted the lithofacies and environments of deposition in outcrops in Utah and Colorado. The interval is interpreted as a transgressive system with deposits progressing from inland environments in the Cedar Mountain Formation, through coastal in the Naturita Formation, and marine in the overlying Mancos Shale. Young (1960) also shows that the sandstone bodies found in Escalante Canyon below the green mudstone are equivalent to the lower and middle Cedar Mountain Sandstones to the west by recording and correlating 150 stratigraphic sections throughout the Colorado Plateau. Young (1970, 1975) regionally correlates the lithology and environments of deposition of Lower Cretaceous deposits in the study area and surrounding areas using outcrop-based studies. Since the 1970s, there has been limited published work on the stratigraphy, lithofacies, and depositional setting of the Burro Canyon Formation in the southern Piceance Basin.

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The limited studies of the Burro Canyon interval have focused mainly on the regional stratigraphy and age of the formation, and none have investigated the interval at a smaller scale. To better understand (1) the reservoir-scale sedimentology and stratigraphy of the Burro Canyon interval and (2) the significance of the different scales of fluvial heterogeneity, this study expands on relevant previous work and analyzes lithofacies, architectural elements, and their characteristics to interpret the environment of deposition and evaluate the stratigraphic variability of the deposits.

Figure 1. Stratigraphic nomenclature used in this study and past studies. The Cretaceous deposits have been divided and named multiple ways by various studies in the past. The Burro Canyon Formation is the target of this study. Modified from Cole (personal communication, 2017).
using multiscale fluvial reservoir modeling and fluid-flow simulations from the scale of facies to that of amalgamated channel complexes. Model construction and quantification of stratigraphic and sedimentological heterogeneity sequentially includes additional smaller scales of stratigraphic detail beginning with (1) 2D model construction of fluvial reservoir stratigraphic heterogeneity, (2) incorporation of sandstone-body (architectural-element) scale analysis and modeling, and (3) incorporation of smaller scale bedding/lithofacies modeling of internal architectural-element heterogeneity. Each smaller scale of heterogeneity is added to the previous larger scale features. Importantly, secondary recovery performance is evaluated to determine the significance of stratigraphic and sedimentological features on dynamic processes. Multiple 2D static and dynamic outcrop-based models of the Burro Canyon Formation were constructed using Schlumberger’s Petrel E&P software. Additionally, the implication of upscaling geologic-model grid resolution (cell size) for fluid-flow simulation is investigated in terms of BTT, volumetric sweep efficiency, and recovery efficiency.

Geologic setting
The Piceance Basin is a northwest–southeast-trending basin surrounded by the White River uplift to the east, Axial arch and Uinta Mountains to the north, Douglas Creek arch to the west, Uncompahgre uplift to the southwest, Gunnison uplift and Elk Mountains to the south, and Sawatch uplift to the southeast (Johnson, 1989). The basin began forming in the Late Cretaceous (Campanian) during the Laramide Orogeny (approximately 75–40 Ma) (Johnson and Flores, 2003). The Piceance Basin now resides in an area once dominated by a much larger Rocky Mountain Foreland Basin System that was created by the Sevier Orogeny (approximately 140–50 Ma) (Johnson and Flores, 2003). Clastic sediments were carried from the Sevier belt to the northeast by fluvial systems in multiple pulses of sedimentation because of the rising orogenic movement in the Early Aptian, with periods of less active erosion and meandering stream systems in between each of the pulses. During early Albian time, a shallow sea encroached from the north and south bringing new depositional environments to the former coastal plain. The sea spread and approached northwestern Colorado from the northeast drastically shrinking the coastal plain just prior to the end of the Albian (Young, 1975). Basin development during the Early Cretaceous through early Late Jurassic basin was dominantly caused by flexural subsidence, whereas Late Cretaceous to mid-Cenozoic time saw basin partitioning caused by basement-involved Laramide structures (DeCelles, 2004) (see the summaries in Johnson and Flores, 2003; DeCelles, 2004).

The Burro Canyon Formation is Aptian-Albian in age, lies unconformably on top of the Morrison Formation, and is overlain unconformably by the Dakota Formation (Figure 1). The Burro Canyon Formation in Colorado is the stratigraphic equivalent to the Cedar Mountain Formation in Utah. It is composed of mainly sandstones and conglomerates that are regularly encountered in the lower half of the Burro Canyon Formation and are thought to be deposited by northeast–east-trending braided-river systems within incised valleys from a source in the Sevier Orogenic belt (Young, 1975). A laterally continuous, green mudstone deposit is found encasing sandstone deposits in the upper portion of the Burro Canyon Formation. This mudstone was most likely deposited in a meandering stream, floodplain, or lacustrine environment (Young, 1975; R. Cole, personal communication, 2017).

Methodology

Conventional field methods
To analyze the stratigraphy and interpret the environment of deposition of the Burro Canyon Formation,
two stratigraphic sections (measured sections MS-1 and MS-2) were measured and described along the west and east sides of 650 road in Escalante Canyon (Figure 3). The measured sections cover approximately 160 m (524 ft) and traverse through the upper portions of the Morrison, Burro Canyon, and Dakota Formations. The measured sections include descriptions of lithology, grain size, sedimentary structures, paleocurrent indicators, and bounding surfaces. A Brunton Compass was used to acquire paleocurrent measurements (N = 120) by measuring the dip and azimuth of cross-stratification and scour surfaces. Outcrop gamma-ray (GR) measurements were also acquired along both measured section traverses to assist in lithology identification and for comparison with subsurface well logs (comparison with the Mitchell Energy 8-1 Federal core in Mesa County, Colorado). Total-count GR data were acquired using 0.3 m (1 ft) spacing with a Super-Spec RS-125 scintillometer (Radiation Solutions, Inc.).

**UAV-based photogrammetry**

High-resolution (12 megapixels) calibrated images of the 816 m (2677 ft) long south-facing exposure along the Gunnison River were captured at multiple distances using a DJI Phantom 3 drone (unmanned aerial vehicle [UAV]) (Figure 3). Images are from approximately 3 m (10 ft) away from the outcrop face to facilitate identification of small-scale sedimentary structures and lithofacies associations in areas that were not accessible. A second set of images was acquired from a distance of approximately 15–30 m (50–100 ft) to provide data to capture the large-scale features of the outcrop, correlate stratigraphic surfaces, map and measure architectural elements and their bounding surfaces, and evaluate how those elements vary stratigraphically. Multiple 3D renderings of the outcrop were produced using georeferenced images in the Pix4DMapper Pro software to create 3D dense point clouds with overlying 3D meshes for interpretation (Figure 4). Images taken of the outcrop with the UAV were captured with no less than 75% overlap in three dimensions or a maximum camera angle change of approximately 15° between subsequent images to ensure a high level of accuracy in the 3D models. Images were captured with oblique and parallel angles to the outcrop face in an approximate grid across the entire study area to retain the detailed geometry of the rocks. The flight path and shooting positions were planned at the outcrop location prior to shooting once the area of interest for reservoir modeling was identified. Within Pix4DMapper Pro, uncertainty ellipses can be displayed over image locations in map view to assess how well the images were calibrated in addition to how many matches were found between adjacent images to produce a high-resolution model. The uncertainty ellipses in the models used in this study were all generally the same size, indicating that they were calibrated properly.
and sufficient matches were found (for further reading on how UAVs and Pix4DMapper Pro can be used in outcrop interpretation, see Chesley et al., 2017; Nieminski and Graham, 2017).

Width and thickness values of sandstone bodies were measured from the georeferenced 3D renderings of the outcrop in Pix4DMapper Pro to assist in interpreting the architectural elements in the Burro Canyon Formation. Using measured sections and UAV-based imaging, four properties were considered to define architectural elements: bounding surfaces, scale, external geometry, and internal geometry (Miall, 1985).

Measured sections recorded in Escalante Canyon were used to interpret lithofacies and bounding surfaces observed in the 3D outcrop rendering. The 13 vertical “pseudowells” were created at approximately 50 m (164 ft) spacing across the outcrop, and lithofacies and bounding surfaces were recorded along their traverses (Figure 4). The pseudowells were imported into Petrel, and discrete lithofacies logs were created from the measured section interpretations and from the drone imagery to constrain lithofacies models (Figure 5). Bounding surfaces were also interpreted in the outcrop rendering and were imported into Petrel and digitized as surfaces to create zones for the three model scenarios.

**Outcrop reservoir modeling**

Three 2D outcrop-based reservoir models (models 1–3) of the Burro Canyon Formation along the 816 m (2677 ft) long exposure (Figure 3) were constructed using commercial software to explore the different scales of fluvial heterogeneity observed in Escalante Canyon. The models were created with a 1×1 m (3.2×3.2 ft) lateral grid size to capture small-scale variations in facies and petrophysical trends. The models are approximately 816×25×60 m (2677×82×196 ft) in the x-, y-, and z-directions of a Cartesian-grid system and vary in the total number of cells: Model 1 is 13,623,475 cells, model 2 is 17,933,150 cells, and model 3 is 25,715,075 cells. The number and shape of zones changes in each model, but layering was kept at 0.1 m (0.3 ft) for all reservoir zones to capture the finer stratigraphic variation (Figure 6). The three models were created to represent increasing levels of heterogeneity to explore their effects on fluid flow. Model 1 is the least heterogeneous scenario and contains only cross-stratified sandstone and gray-green mudstone lithofacies with reservoir

![Figure 4](image-url). (a) An overview image of Escalante Canyon. The view is from the south-facing outcrop chosen for reservoir modeling (b) and the outcrop cut along 650 Road used for recording measured sections. (b) The southern-facing wall of the Escalante Canyon along the Gunnison River was chosen for the outcrop reservoir models because of the excellent exposure of the sandstone bodies of the Burro Canyon formation. The 13 pseudowells (PW 1-13) used to create lithofacies logs along their traverses are shown as the black dashed lines. The reservoir model boundaries are indicated by the solid black lines.
bodies in contact with injector and producer wells (Figure 6a). Model 2 is an intermediate scenario with five lithofacies and the addition of isolated reservoir bodies (Figure 6b). Model 3 is the most heterogeneous scenario and the closest approximation to the actual outcrop. It contains five lithofacies, additional zones based on channel-bounding surfaces, and petrophysical trends imposed in some reservoir zones in which decreasing-upward porosity is associated with fining-upward sandstones and conglomeratic sandstones (Figure 6c). Models were constructed at reservoir depth using the Burro Canyon Formation depths from the Mitchell Energy 8-1 Federal core to accurately represent the temperature and pressure environment during the fluid-flow simulation process.

**Lithofacies modeling**

Lithofacies models were created for the three lithofacies scenarios (models 1–3) using sequential-indicator simulation and are constrained to the model zones (stratigraphic framework), lithofacies logs for measured sections and pseudowells, lithofacies percentages from outcrop, and variogram inputs based on measurements of the lateral and vertical continuity of lithofacies acquired from a UAV-based 3D rendering of the outcrop. The outcrop is oriented approximately perpendicular to the paleoflow direction of 51°, so the major direction of continuity is set to 51° for all models and zones.

**Petrophysical modeling**

Porosity and permeability models were created for the three lithofacies scenarios (models 1–3) using sequential-Gaussian simulation and were conditioned to

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**Figure 5.** (a) Overview image of the outcrop in Escalante Canyon used for reservoir modeling, showing an example of a lithofacies log created along a pseudowell traverse. The UAV-based outcrop renderings were created in Pix4D-Mapper Pro and used to interpret lithofacies within the Burro Canyon Formation to apply to outcrop reservoir modeling. (b) Image captured with the DJI Phantom 3 from approximately 3 m (10 ft) away from the rock face along the pseudowell shown in (a) to capture small-scale details such as lithology and sedimentary structures. An example lithofacies log is interpreted along the image. The 13 pseudowells with interpreted logs were then used to constrain lithofacies models later in the study.

**Figure 6.** The 2D stratigraphic framework for each model scenario (models 1–3). (a) Model 1 is the least heterogeneous and contains nine zones (each zone is indicated by a unique color except for the floodplain facies in gray). (b) Model 2 contains 14 zones. (c) Model 3 is the most heterogeneous scenario and contains 24 zones. The models all contain a 1 × 1 m (3.2 × 3.2 ft) lateral grid, and the reservoir zones (nonmudstone) are divided into 0.1 m (0.3 ft) vertical layers. Models are 816 × 25 × 57 (2677 × 82 × 196 ft) in the x-, y-, and z-directions of a Cartesian grid system. The total cells contained in the models are model 1, 13,623,475; model 2, 17,933,150; and model 3, 25,715,075.
the corresponding lithofacies model. Porosity and permeability data were obtained from the Mitchell Energy 8-1 Federal core in Mesa County, Colorado (Figure 2). Minimum, maximum, and mean values and the standard deviation were used to establish porosity and permeability histograms for each lithofacies and used to constrain the models. In all models, nonreservoir zones (mudstone lithofacies) were set to 0% for porosity and 0 mD for permeability. Variogram information was assigned based on values used in the lithofacies models with consideration of published values in other fluvial-reservoir modeling studies (e.g., Pranter et al., 2009). Model 3 includes upward-decreasing porosity-depth trends for zones containing upward-fining sandstone and conglomeratic sandstone lithofacies.

The trends were created in two ways depending on if the zone exhibits a single upward-fining trend or multiple upward-fining cycles: (1) a linear function in stratigraphic depth assuming isotropic conditions in the horizontal plane that created a continuous trend through the whole reservoir zone and (2) for zones containing multiple cycles of thin-bedded (approximately 0.3 m; approximately 1 ft) upward-fining sandstone, porosity logs were created for the pseudowells and used to impose the trends at smaller intervals. Permeability models were created with core-derived data distributions, and cokriging was used to constrain permeability to the porosity models to ensure the permeability models relate to porosity trends for each scenario. Uniform porosity and permeability models were also created for each model scenario by assigning an average porosity and permeability value to the fine- to medium-grained cross-stratified sandstone facies. These models represent the most simplistic petrophysical models (base case) to compare with more complex scenarios during fluid-flow experiments.

**Model upscaling**

Because of the limitations in computational power and associated run time, small-scale geologic models must often be upscaled prior to fluid-flow simulation. The original static outcrop models are detailed and geologically accurate and include many cells (the cell counts varied from 13 to 26 million cells); therefore, upscaling was required. Importance is placed on using appropriate upscaling methods to maintain important small-scale geologic features that affect fluid flow, while still coarsening the grid adequately to simulate fluid flow within a reasonable timeframe.

Averaging (volume-weighted) algorithms were used to aerially upscale lithofacies and petrophysical models from a 1 × 1 m (3.2 × 3.2 ft) grid to three larger grid sizes: 2 × 2 m (6.5 × 6.5 ft), 4 × 4 m (13 × 13 ft), and 8 × 8 m (26.2 × 26.2 ft) to assess the effects of upscaling on reservoir performance. Only the aerial cell dimensions were upcaled; vertical upscaling was not done to the model layers. It is important to note that the stratigraphic details were preserved vertically. For lithofacies upscaling, the most abundant lithofacies is assigned to the upscaled model cell. For porosity upscaling, the arithmetic mean is calculated for the upscaled model cell. Two averaging methods, harmonic and geometric, were used to

Table 1. Summary of upscaled models used in fluid-flow simulations.

<table>
<thead>
<tr>
<th>Model name</th>
<th>Algorithm</th>
<th>Averaging method (porosity)</th>
<th>Averaging method (permeability)</th>
<th>Total number of cells</th>
</tr>
</thead>
<tbody>
<tr>
<td>Model 1_2X 2H</td>
<td>Averaging (volume-weighted)</td>
<td>Arithmetic</td>
<td>Harmonic</td>
<td>3,532,464</td>
</tr>
<tr>
<td>Model 1_2X 2G</td>
<td>Averaging (volume-weighted)</td>
<td>Arithmetic</td>
<td>Geometric</td>
<td>815,184</td>
</tr>
<tr>
<td>Model 1_4X 4H</td>
<td>Averaging (volume-weighted)</td>
<td>Arithmetic</td>
<td>Harmonic</td>
<td>204,102</td>
</tr>
<tr>
<td>Model 1_4X 4G</td>
<td>Averaging (volume-weighted)</td>
<td>Arithmetic</td>
<td>Geometric</td>
<td>4,651,608</td>
</tr>
<tr>
<td>Model 1_8X 8H</td>
<td>Averaging (volume-weighted)</td>
<td>Arithmetic</td>
<td>Harmonic</td>
<td>1,073,448</td>
</tr>
<tr>
<td>Model 1_8X 8G</td>
<td>Averaging (volume-weighted)</td>
<td>Arithmetic</td>
<td>Geometric</td>
<td>270,504</td>
</tr>
<tr>
<td>Model 2_2X 2H</td>
<td>Averaging (volume-weighted)</td>
<td>Arithmetic</td>
<td>Harmonic</td>
<td>6,667,128</td>
</tr>
<tr>
<td>Model 2_4X 4G</td>
<td>Averaging (volume-weighted)</td>
<td>Arithmetic</td>
<td>Geometric</td>
<td>1,534,896</td>
</tr>
<tr>
<td>Model 3_2X 2H</td>
<td>Averaging (volume-weighted)</td>
<td>Arithmetic</td>
<td>Harmonic</td>
<td>386,478</td>
</tr>
</tbody>
</table>

Model names indicate BC, Burro Canyon; M1, model 1; M2, model 2; M3, model 3; 2 × 2, 2 × 2 m lateral grid; 4 × 4, 4 × 4 m lateral grid; 8 × 8, 8 × 8 m lateral grid; H, harmonic; G, geometric. Uniform property model simulations are not included in the list but were created and used in flow simulations for each grid size in each model scenario.
coarsen the permeability models for each grid size to assess the effects of upscaling methods on reservoir performance. Six unique grids for each of the three model scenarios were produced, and one uniform scenario (average values of porosity and permeability for sandstone) was created for each grid size and model scenario. The result is a total of 27 simulation scenarios that were evaluated (Table 1).

**Effect of fluvial reservoir heterogeneity on waterflood performance**

To investigate the effect of fluvial-reservoir heterogeneity (lithologic and petrophysical) and the impact of upscaling geologic models on reservoir performance, the subsurface fluid-flow was simulated over a 15 year period using Schlumberger’s ECLIPSE reservoir simulation software. Waterflood performance in light oil reservoirs was investigated using an injector-producer pair. The injection and production wells were placed on the west (left) and east (right) sides of the outcrop models, respectively. The wells penetrate the entire thickness of the model, and only reservoir zones were completed for both wells. The effects of heterogeneity and model resolution on frontal displacement within waterflood settings were determined. Simulations are evaluated in terms of the (1) BTT, (2) volumetric sweep efficiency at BTT, (3) recovery efficiency at BTT and at 15 years, and (4) cumulative production of oil, gas, and water at 15 years.

The initial reservoir pressure and fluid distributions as well as operational conditions were kept the same for all 27 scenarios explored. Parameters for fluids, initial conditions, relative permeability, and compaction used in these scenarios are presented in Table 2. Petrophysical properties, namely, porosity and permeability as described previously, were used for each unique grid scenario. The permeability was considered laterally isotropic, whereas the vertical permeability anisotropy was set at 0.1.

Production was controlled by a maximum allowable flow rate from the producing well initially, and when pressure declined, a minimum bottom-hole pressure was imposed. Water injection was controlled by a maximum injection flow rate and a maximum bottom-hole pressure limit (Table 2).

**Results**

### Lithofacies and stratigraphic architecture

Burro Canyon Formation lithofacies from MS 1 and 2 are (1) granule-cobble conglomerate, (2) conglomeratic sandstone, (3) cross-stratified sandstone, (4) fining-upward sandstone, and (5) gray-green mudstone (Figure 7; Table 2. Summary of parameters used in fluid-flow simulations. Parameters were held constant through all simulations: reservoir inputs for simulations and controls on injection and production throughout simulations.

<table>
<thead>
<tr>
<th>Reservoir inputs for simulations</th>
<th>Parameters</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fluids</td>
<td>Oil density</td>
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<tr>
<td></td>
<td>Gas gravity</td>
<td>0.66 sg air</td>
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<tr>
<td></td>
<td>Water salinity</td>
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<tr>
<td></td>
<td>Bubble-point pressure</td>
<td>300 bar (4590 psi)</td>
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<tr>
<td>Initial reservoir condition</td>
<td>Pressure</td>
<td>69 bar (1010 psi)</td>
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<tr>
<td></td>
<td>Datum depth</td>
<td>700 m (2297 ft)</td>
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<tr>
<td></td>
<td>Oil-water depth</td>
<td>900 m (2952 ft)</td>
</tr>
<tr>
<td>Contact oil-water capillary pressure</td>
<td>Temperature</td>
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</tr>
<tr>
<td></td>
<td></td>
<td>77°C (170°F)</td>
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<tr>
<td>Relative permeability parameters</td>
<td>Critical water saturation</td>
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</tr>
<tr>
<td></td>
<td>Commate water saturation</td>
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<tr>
<td></td>
<td>Residual oil saturation</td>
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</tr>
<tr>
<td></td>
<td>Corey coefficient (oil/water)</td>
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</tr>
<tr>
<td></td>
<td>Corey coefficient (water)</td>
<td>3</td>
</tr>
<tr>
<td>Compaction parameters</td>
<td>Reference pressure</td>
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<tr>
<td></td>
<td>Rock compressibility</td>
<td>1.5e-5 1/bar (1.0e-6 1/psi)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Controls on injection and production throughout simulations</th>
<th>Parameters</th>
<th>Values</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum oil production rate</td>
<td>10 sm³/d (63 bbl/d)</td>
<td></td>
</tr>
<tr>
<td>Maximum water injection rate</td>
<td>15 sm³/d (94 bbl/d)</td>
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</tr>
<tr>
<td>Minimum producer bottom-hole pressure</td>
<td>25 bar (363 psi)</td>
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</tr>
<tr>
<td>Maximum injector bottom-hole pressure</td>
<td>200 bar (2900 psi)</td>
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</tr>
</tbody>
</table>
Table 3). Cross-stratified sandstone is the dominant facies of the interval, and it is commonly associated with relatively large-scale amalgamated channel complexes, whereas gray-green mudstone commonly encases sandstone bodies in nonamalgamated channel complexes. Conglomerate and sandstone facies are considered reservoir facies and mudstone facies are nonreservoir for the outcrop reservoir models.

An idealized stratigraphic section that combines data from two measured sections illustrates the common facies associations (Figure 8). For the Burro Canyon Formation, a general fining-upward succession exists. A granule-cobble conglomerate lies at the base of the formation at the K-1 unconformity with conglomeratic sandstone facies directly overlying it. Cross-stratified sandstone overlies the conglomeratic sandstone and is the most abundant facies in this area. The cross-stratified sandstone generally thins and fines upward and is overlain by the slightly coarser grained fining-upward sandstone facies. Fining-upward sandstone lies directly below the gray-green mudstone facies.

The stratigraphic architecture of the Burro Canyon Formation follows the hierarchy of alluvial strata established by Patterson et al. (2002, 2010), which describes three facies associations composed of small-scale hierarchical elements that vertically stack to create the external geometry of the reservoir zones and the small-scale, internal heterogeneity (Figure 9). The Burro Canyon Formation in the study area forms a depositional sequence, which is composed of an amalgamated channel complex, formed by channel-fill elements, which amalgamated over time, overlain by a nonamalgamated channel complex, which contains smaller, disconnected channel-fill elements surrounded by floodplain facies (Figure 9). Patterson et al. (2010) define the channel-fill element as a relatively conformable succession of genetically related bar or bar-set deposits within a channel defined by bankfull discharge. The channel-fill element has a concave-up basal geometry, and when preserved, it is bounded on top by a transition from channel lithofacies (sandstone-dominated) to floodplain lithofacies (mudstone-dominated). Channel-top facies are commonly eroded during subsequent channel deposition because of basal scouring.

Four main facies associations that comprise the amalgamated and nonamalgamated channel complexes are described below using the naming convention of Patterson et al. (2002) (Figure 10).

Facies association 1: Amalgamated channel complex

The amalgamated channel complex consists of vertically stacked channel-fill elements, and it is the largest element in the Burro Canyon Formation (Figure 10). The typical facies sequence observed in the channel-fill elements is characterized by a scour surface along a concave-up channel-base and a conglomeratic lag deposit that transitions into a low-angle inclined cross-stratified conglomeratic sandstone, which fines and thins upward. Normally, graded beds are common in this lithofacies. Thick packages of stacked sandy bars are directly above the conglomeratic sandstone. The barsets exhibit a variety of stratification types such as tabular-planar and wedge-tangential cross stratification, and less commonly horizontal planar bedding. Sandy cross-stratified bars tend to have erosional bases with limestone and quartzite clasts lining scour surfaces as gravel lag deposits. Channel-body tops, when preserved, transition from cross-stratified sandstone lithofacies (sandy barsets) to overbank mudstone facies (Walker and Cant, 1984). Channel tops are not pre-

<table>
<thead>
<tr>
<th>Formation</th>
<th>Facies</th>
<th>Grain size</th>
<th>Grain shape/sorting</th>
<th>Dominant features</th>
<th>Environment of deposition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Burro Canyon</td>
<td>Granule-cobble conglomerate</td>
<td>Very coarse sand matrix; &lt; 7 cm clasts</td>
<td>Subangular, moderately sorted matrix; round-subround clasts</td>
<td>Low-angle cross-stratification</td>
<td>Braided fluvial</td>
</tr>
<tr>
<td>Burro Canyon</td>
<td>Conglomeratic sandstone</td>
<td>Medium to very coarse sand matrix; &lt; 9 cm clasts</td>
<td>Subround, moderately sorted matrix; subround clasts</td>
<td>Large-scale low-angle inclined bedding, clasts commonly found in densely clustered lenses; graded bedding</td>
<td>Braided fluvial, channel fill</td>
</tr>
<tr>
<td>Burro Canyon</td>
<td>Cross-stratified sandstone</td>
<td>Fine to medium</td>
<td>Subround-subangular, well-sorted</td>
<td>Varying medium-scale cross-stratification, gravel lag at scour surfaces (mudstone and quartzite)</td>
<td>Braided fluvial, channel fill</td>
</tr>
<tr>
<td>Burro Canyon</td>
<td>Fining-upward sandstone</td>
<td>Fine to medium</td>
<td>Subangular, fining-upward cycles</td>
<td>Low-angle inclined bedding; mudchips along the base of the cycles</td>
<td>Sinuous fluvial, decreasing system energy</td>
</tr>
<tr>
<td>Burro Canyon</td>
<td>Gray-green mudstone</td>
<td>Clay</td>
<td>N/A</td>
<td>Unconsolidated, structureless to silicified and thinly laminated</td>
<td>Floodplain</td>
</tr>
</tbody>
</table>

Grain shape interpretations based on Powers (1953).
Figure 7. Key facies of the Burro Canyon Formation shown in (a-e) outcrop and in (f-j) thin section. Thin sections are in plane-polarized light and stained red for calcite (epoxy is blue). (a and f) Granule-cobble conglomerate, (b and g) conglomeratic sandstone, (c and h) cross-stratified sandstone, (d and i) fining-upward sandstone, and (e and j) gray-green mudstone. These lithofacies were used to populate the lithofacies models (models 1–3).
served within the body of this architectural element because upper channels eroded into the tops of lower channels preventing overbank fines from being preserved. The channel-fill elements stack vertically and laterally to form amalgamated channel complexes, which are thick and laterally extensive. The lateral extent of the amalgamated channel complex is larger than what is exposed in outcrop, but what is exposed is approximately 816 m (2677 ft) perpendicular to paleoflow orientation. The channel complex thickness is an average of 17.5 m (57 ft).

**Facies association 2: Amalgamated fluvial-bar channel-fill deposits**

Amalgamated fluvial-bar channel-fill deposits contain packages of sandstone with low-angle inclined cross-stratification to horizontal bedding. Sandstone beds fine upward and commonly contain mudstone rip-up clasts along basal surfaces. Individual beds stack vertically to create barsets that comprise amalgamated fluvial-bar channel-fill deposits. These deposits are less laterally extensive than the amalgamated channel complexes of facies association 1 and are encased in floodplain mudstones. Together with facies association 3, they form a nonamalgamated channel complex (Figure 10). This architectural element is on average 438 m (1437 ft) wide perpendicular to the channel flow and 12 m (38 ft) thick.

<table>
<thead>
<tr>
<th>Age</th>
<th>Formation</th>
<th>Outcrop gamma-ray (CPS)</th>
<th>Lithology</th>
<th>Environment</th>
</tr>
</thead>
<tbody>
<tr>
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<td>K-1 unconformity</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Morrison Formation</td>
<td>60</td>
<td>Fluvial, mudflat, and lacustrine</td>
<td></td>
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<td></td>
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<tr>
<td>Apalian</td>
<td>Burro Canyon Formation</td>
<td>220</td>
<td>NE-trending, low-sinuosity braided river</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Unconformity Lag</td>
</tr>
<tr>
<td></td>
<td></td>
<td>240</td>
<td></td>
<td>Floodplain or lacustrine</td>
</tr>
<tr>
<td></td>
<td>K-2 unconformity</td>
<td></td>
<td></td>
<td>High-sinuosity fluvial, swamp-marsh, estuarine-tidal channel</td>
</tr>
<tr>
<td></td>
<td>Dakota Formation</td>
<td>300</td>
<td></td>
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<td></td>
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<td>280</td>
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<td>240</td>
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**Figure 8.** Composite stratigraphic section based on measured sections taken in Escalante Canyon. Outcrop GR increases from left to right and is merged from two traverses. The Burro Canyon Formation has a fining-upward character overall in the study area and contains high-energy, low-sinuosity to lower energy, sinuous fluvial deposits with thick intervals of mudstone floodplain deposits.

**Figure 9.** Idealized illustration of alluvial hierarchical elements. The channel sandstones are shown in yellow, floodplain mudstones are in green, levee sandstones are in brown, and crevasse splays are in pink. The red lines indicate sequence boundaries. The colored triangles are associated with each hierarchical element. The Burro Canyon Formation contains a channel complex sequence in Escalante Canyon and is composed of small- to intermediate-scale hierarchical elements, such as beds and bedsets, bars and barsets, channel fills, and channel complexes. From Patterson et al. (2010); modified from Sprague et al. (2002).
**Facies association 3: Isolated fluvial-bar channel-fill deposits**

Isolated fluvial-bar channel fills are like amalgamated fluvial-bar channel fills in that they contain sandstones with low-angle inclined cross-stratification to horizontal bedding. The sandstone grain size decreases upward within individual beds, and mudstone rip-up clasts are common along scour surfaces. Beds stack vertically to form fining-upward sandstone successions that compose the isolated fluvial-bar channel-fill deposits. Facies association 3 is completely isolated and encompassed in floodplain mudstones and is much less laterally extensive than facies association 2, and together they comprise nonamalgamated channel complexes (Figure 10). The isolated bar deposits measure on average 137 m (449 ft) wide perpendicular to channel flow and are 4 m (13 ft) thick.

**Facies association 4: Floodplain deposits**

Floodplain deposits are composed of mudstone facies, encase channel deposits, and have no discrete boundaries. Within the mudstone beds in the study area, there are no sandstone layers; therefore, floodplain deposits are considered nonreservoir rocks in this study.

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**Outcrop reservoir models**

**Lithofacies models**

Three lithofacies model scenarios were constructed of the Burro Canyon Formation to explore different levels of heterogeneity within the fluvial deposits (Figure 11a–11c). All nonreservoir zones (facies association 4) were modeled as homogeneous mudstone facies in all model scenarios. The most simplistic reservoir scenario, model 1, (Figure 11a) represents facies associations 1, 2, and 4 (amalgamated channel complex, amalgamated fluvial-bar channel fill, and floodplain) and only contains cross-stratified sandstone and gray-green mudstone facies. This model assumes that there is no internal lithologic heterogeneity in the reservoir bodies, and it is used as a base case for comparison with the more complex and geologically representative models. All facies associations (1–4) are included in model 2 (Figure 11b), and the internal lithologic heterogeneity of the main amalgamated channel complex is controlled by lithofacies logs to more accurately represent the lithofacies successions observed in outcrop. The most geologically representative model, model 3, (Figure 11c) incorporates the channel-bar architecture within the
amalgamated channel complex and the geometries associated with irregular channel-scour surfaces (channel basal surfaces) and associated facies. The channel-scour surfaces and the associated facies can impact fluid movement through the amalgamated channel complex.

Petrophysical models

Three porosity and three permeability models were constrained to the three different lithofacies model scenarios and variogram inputs (Figure 12). Model 1 porosity (Figure 12a) and permeability (Figure 12b) volumes are constrained by core-derived values for cross-stratified sandstone in the reservoir zones. As a result, the upper reservoir zones contain much higher porosity and permeability values than in models 2 (Figure 12c and 12d) and 3 (Figure 12e and 12f), in which the upper zones are populated with fining-upward sandstone petrophysical values, which are lower than those of the cross-stratified sandstone lithofacies. The main amalgamated channel complex in model 1 has more variation in petrophysical values than in models 2 and 3. This is because the entire zone is populated with one lithofacies that has a wider range of values in model 1 (Figure 11a), whereas models 2 (Figure 11b) and 3 (Figure 11c) incorporate three lithofacies in that zone and are constrained by each of their coinciding petrophysical values, which have less variability overall than the cross-stratified sandstone in model 1. In the porosity and permeability volumes for model 1, there are larger patches of values than in the other models because they are not constrained to lithofacies well logs. Model 3 contains channel bounding surfaces that control the orientation of lithofacies distributions within the amalgamated channel complex, which

Figure 11. Lithofacies models were created for each model scenario (1–3) (a-c) of the southern exposure of the Burro Canyon Formation in Escalante Canyon. There is increasing complexity included in each succeeding model to assess the impact of internal heterogeneity and sandstone-body connectivity on fluid-flow analysis. (a) Model 1 contains only cross-stratified sandstone and mudstone and only amalgamated architectural elements. (b) Model 2 includes all facies associations and key lithofacies seen in the Burro Canyon Formation. (c) Model 3 introduces channel-bases within the amalgamated channel complex in the middle of the model. Pseudowells with lithofacies logs that were used to constrain models 2 and 3 are shown as dashed black lines.

Figure 12. Porosity and permeability models were created for each model scenario (1–3) on the southern exposure of the Burro Canyon Formation. All models used porosity and permeability data from the Mitchel Energy 8-1 Federal core and were constrained to their associated lithofacies model. (a) Model 1 is populated with porosity and permeability data associated with cross-stratified sandstone. (b) Model 2 uses porosity and permeability data for all lithofacies modeled in the scenario. (c) Model 3 introduces decreasing-upward porosity trends associated with fining-upward sandstones and conglomeratic sandstones. In all scenarios, all nonreservoir zones (mudstone lithofacies) were set to 0% porosity and 0 mD permeability.
Figure 13. Cumulative oil and gas production graphs are produced after all fluid-flow simulations for (a, d) model 1 simulations, (b and e) model 2 simulations, and (c and f) model 3 simulations. The upper reservoir zones in model 1 have cross-stratified sandstone, which consists of higher porosity and permeability than the fining upward sandstones of models 2 and 3. The cumulative oil production from these deposits is greater in model 1 than in models 2 and 3, with model 3 having the lowest cumulative production because of the fining-upward sandstones that exhibit lower reservoir quality. Model 1 simulations produced 13,000 (82,000 bbl) to 18,200 sm³ (114,000 bbl) oil (39% increase) compared with model 2 simulations, which produced 13,000 (82,000 bbl) to 17,400 sm³ (110,000 bbl) oil (33% increase) and model 3 simulations, which produced 13,000 (82,000 bbl) to 16,800 sm³ (106,000 bbl) oil (29% increase). Overall, this represents a 0.5% decrease in cumulative oil production for the lowest producing simulation, 8×8 grid, from models 1 to 3 and a 7.3% decrease for the highest producing simulations, 2×2U grid for model 1 and 8×8U grid for model 3. Cumulative gas production is greater in model 1 than in models 2 and 3. Model 1 simulations produced 682,000 (429,000 bbl) to 914,000 sm³ (5,751,000 bbl) gas (34% increase); model 2 simulations produced 629,000 (3,956,000 bbl) to 891,000 sm³ (5,605,000 bbl) gas (41% increase); and model 3 simulations produced 635,000 (3,993,000 bbl) to 816,000 sm³ (5,135,000 bbl) gas (28% increase). There is a 6.9% and 10.7% decrease in the lowest and highest cumulative gas production, respectively, from model 1 to model 3.
in turn controls the directionality of petrophysical values. In model 2, variograms alone are constraining the distribution of porosity and permeability values in the amalgamated channel complex.

**Impact of heterogeneity on flow**

The 27 dynamic fluid-flow simulations were performed to investigate how lithofacies and petrophysical property variations within fluvial deposits impact reservoir performance. Porosity and permeability models conditioned to lithofacies models were used to conduct fluid-flow simulations for each of the three lithofacies heterogeneity scenarios.

Floodplain mudstones are the most important barriers to flow preventing fluid communication from the upper and lower reservoir zones to the amalgamated channel complex. The upper reservoir zones (facies associations 2 and 3) show that lithofacies and petrophysical trends are important even in isolated reservoirs that are not connected to the injector well. The upper reservoir zones in model 1 have cross-stratified sandstone with higher porosity and permeability than the upward-fining sandstones in the same reservoir zones of models 2 and 3 (Figure 12). Therefore, cumulative oil and gas production from these deposits is greater in model 1 than in models 2 and 3, with model 3 having the lowest cumulative production (Figure 13; Table 4). Overall, there is a 0.5% decrease in cumulative oil production for the lowest producing simulation, $8 \times 8$ H grid, from models 1 to 3 and a 7% increase for the highest producing simulations, $2 \times 2$ U grid for model 1, and $8 \times 8$ U grid for model 3. There is a 7% and an 11% decrease in lowest and highest cumulative gas production, respectively, from models 1 to 3.

The degree of fingering, defined as a preferential channeling of fluids (sensu Willhite, 1986), varies between the three model scenarios. In model 1, reservoir zones are all assigned cross-stratified sandstone and associated petrophysical properties. This creates a more homogeneous reservoir than in models 2 and 3, in which multiple lithofacies are included. Conglomerates have lower petrophysical properties than cross-strati-

<table>
<thead>
<tr>
<th>Model name</th>
<th>Cumulative oil production</th>
<th>Percent change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Model 1</td>
<td>13,000–18,200 sm$^3$ (82,000–114,000 bbl)</td>
<td>39%</td>
</tr>
<tr>
<td>Model 2</td>
<td>13,000–17,400 sm$^3$ (82,000–110,000 bbl)</td>
<td>33%</td>
</tr>
<tr>
<td>Model 3</td>
<td>13,000–16,800 sm$^3$ (82,000–106,000 bbl)</td>
<td>29%</td>
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<table>
<thead>
<tr>
<th>Model name</th>
<th>Cumulative gas production</th>
<th>Percent change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Model 1</td>
<td>682,000–914,000 sm$^3$ (429,000–5,751,000 bbl)</td>
<td>34%</td>
</tr>
<tr>
<td>Model 2</td>
<td>629,000–891,000 sm$^3$ (3,956,000–5,605,000 bbl)</td>
<td>41%</td>
</tr>
<tr>
<td>Model 3</td>
<td>635,000–816,000 sm$^3$ (3,993,000–5,135,000 bbl)</td>
<td>28%</td>
</tr>
</tbody>
</table>

Cumulative oil and gas is greatest in model 1 scenarios and lowest in model 3 scenarios. Model 1 also has the greatest range of cumulative production (39% change from least to greatest oil production and 34% change in gas production), whereas model 3 has the lowest range of cumulative production (20% change in oil production and 28% in gas production).
fied sandstones, thus, creating areas of lower reservoir-quality rock. In addition, fluid flows along pathways in model 3 differently because of the directionality of lithofacies associations within the amalgamated channel complex. The irregular basal scour surfaces of channel deposits in the complex change the orientation and distribution of high-porosity and -permeability lithofacies, such that the injected water follows the curvature of the channel-fill elements (Figure 14).

Model 1 flow simulations have BTT ranging from 67 months for the $2 \times 2G$ grid ($2 \times 2$ m geometric mean upscaling) to 95 months in the $4 \times 4H$ grid with an average of 81 months. Model 2 grids generally show the longest BTT ranging from 94 months in the $2 \times 2H$ grid to 147 months in the $8 \times 8H$ grid with an average of 108 months, representing a 34% increase in average BTT from the lowest BTT seen in model 1 (Figures 14 and 15). Model 3 BTT ranges from 79 months in the $2 \times 2G$ grid to 161 months in the $8 \times 8H$ grid with an average of 106 months. Even though model 3 is the most heterogeneous scenario, the simulations do not have the longest BTT. The irregular basal-scour surfaces of the channels juxtapose high-porosity and -permeability lithofacies against each other, thus creating pathways for fluids to flow across the amalgamated channel complex to the producing well with reduced BTT. In contrast, model 2 has an area of low porosity and permeability in the center of the amalgamated channel complex that reduces fluid flow in the simulations (Figure 16).

Recovery efficiency for oil is the ratio of the cumulative amount of oil produced for a specified period of time divided by the amount of oil initially in place. Recovery efficiency is calculated at BTT and also at the end of the 15 year simulation period (Figure 17b, 17d, and 17f). Generally, recovery efficiencies at the end of the simulation period are very similar between model scenarios, grid sizes, and upscaling methods. Recovery efficiencies at 15 years for model 1 simulations range from 46.6% to 49.9% (48.6% average), model 2 simulations range from 46.2% to 50.2% (48.1% average), and model 3 simulations range from 41.2% to 44.2% (42.3% average),
representing approximately a 13% decrease in average recovery efficiency from models 1 to 3. The lower recovery efficiency of model 3 is because of less water injection into the lower reservoir zones (amalgamated fluvial-bar channel-fill deposits). At BTT, recovery efficiency is also lower in model 3 scenarios ranging from 37.2% to 41% (30% average) as compared with model 1: 37.6% to 45.2% (42.4% average), and model 2: 42.4% to 45.2% (43.6% average). Model 3 has approximately 10% lower recovery efficiency as compared with model 2.

The volumetric sweep efficiency is calculated at BTT and is defined as the volume of reservoir contacted by the injected water at a specified time divided by the total volume of the reservoir. To calculate sweep efficiency in this study, cells with water injection greater than the connate water saturation at BTT were identified, and the sum of the volume of these cells was divided by the total cell volume of reservoir in the model. On average, model 1 simulations display higher volumetric sweep efficiency (61%) than models 2 (60.8%) and 3 (56.2%), representing a 7.8% decrease from models 1 to 3. The sweep efficiency ranges from 53.6% to 69.2% in model 1, from 58.7% to 62.5% in model 2, and from 52.2% to 60.8% in model 3. Similar to recovery efficiency, the lower sweep efficiency of model 3 is because of less water injection into the lower reservoir zones and a more tortuous path for the water flow because of the irregular basal-scar surfaces of the channels in the amalgamated channel complex.

Impact of upscaling on flow

As the aerial cell size increases, the character of the fluid-fingering changes. In the $2 \times 2$ grids, flow pathways are finer, while with larger cells, pathways become broader and tend to become more dispersed (Figure 18). Uniform property model simulations (models with a single value for porosity and permeability assigned to all reservoir zones) show a piston-like water front movement across the amalgamated channel complex.

Simulations performed with $2 \times 2$ grids ($2 \times 2$ m; $6.5 \times 6.5$ ft) typically have the shortest BTT, ranging from 67 to 94 months with an average of 82 months, and those with $8 \times 8$ grids ($8 \times 8$ m; $26.2 \times 26.2$ ft) show the longest BTT, from 87 to 161 months with an average of 117 months — a 42% increase in average BTT. As the grid size increases, pathways of small but connected high-porosity and low-permeability values decrease, forcing fluid to move through larger zones of lower quality rock; essentially, the fluid has an easier time “finding” a pathway to flow through with the smaller grid sizes. Uniform property model simulations for all model scenarios and grid sizes have very similar BTT, ranging from 66 to 69 months. Models using the harmonic mean for upscaling permeability show 17% shorter BTT than models using the geometric mean. This is likely because of the geometric mean preserving higher ranges of permeability than the harmonic mean.

The highest recovery efficiencies at BTT and at the end of the 15 year simulation period are observed in the $8 \times 8$ grid simulations. At BTT, recovery efficiency for the $8 \times 8$ grid ranges from 37.5% to 45.2% (42.4% average), and after 15 years it ranges from 42.1% to 50.2% (46.7% average), whereas the lowest recovery efficiencies are observed for the $2 \times 2$ grid simulations (41% average) at BTT and the $4 \times 4$ grid simulations (45.7% average) at the end of 15 years. This represents a 3.2% decrease in recovery efficiency from the $8 \times 8$ grids to the $2 \times 2$ grids at BTT and a 2.2% decrease after 15 years between the $8 \times 8$ grids and the $4 \times 4$ grids. Higher recovery efficiencies are observed in the $8 \times 8$ grid simulations. Smaller cell sizes in the $2 \times 2$ and $4 \times 4$ grid scenarios create pockets of lower quality rock that are disconnected from higher quality rock, retarding the fluids in place, whereas with larger cell sizes, it is more likely that a single cell will be in contact with a high-quality rock in some degree. Therefore, this makes it possible for injected water to flow more easily through connected pathways of high reservoir quality rock. Models that were upscaled using the geometric mean show higher recovery efficiencies than those up-scaled with a harmonic mean. This is consistent with the geometric mean preserving higher ranges of permeability values than the harmonic mean, allowing for more fluids to be extracted from the higher quality rocks. At BTT, models up-scaled using a geometric versus harmonic mean have an average recovery efficiency.

**Figure 16.** Example of the effect of increased internal heterogeneity on BTT. Model 2 contains a larger area of (a) lower porosity and (b) permeability, which slows fluid movement through the (c) second half of the model causing a longer BTT compared with model 3, which has channel-bases that align the facies with (d) higher porosity and (e) permeability values allowing fluid to flow faster through the same section of (f) the model causing a lower BTT. The black boxes indicate areas of petrophysical variation in the models. Model grids $2 \times 2H$ are shown as an example of this effect.
of 42.3% versus 41%, respectively, representing a 2.9% decrease. After 15 years, these same models have average recovery efficiencies of 47.1% and 45.6%, respectively, representing a 3.1% decrease.

Volumetric sweep efficiency displays similar results to recovery efficiency, where grids with larger cell sizes have higher sweep efficiencies. Simulations using the $8 \times 8$ grids have a sweep efficiency range from 54.6% to 69.2% with an average of 62.7%, $4 \times 4$ grids range from 53.5% to 62.5% with an average of 58.8%, and $2 \times 2$ grids have the lowest recovery efficiencies with a range from 52.2% to 60.4% and an average of 56.8%. This represents an average decrease of 9.3% from the $8 \times 8$ grids to $2 \times 2$ grids. Models that were upscaled using the geometric mean display higher recovery efficiencies than those based on the harmonic mean with average recovery efficiencies of 50.4% and 53.3%, respectively. This represents a 10.4% decrease because of higher permeability values preserved when the geometric mean is used for upscaling.

**Discussion**

**Environment of deposition**

The lower Burro Canyon Formation represents a low-sinuosity braided fluvial environment and grades into a sinuous meandering fluvial environment in the upper portion of the formation. Although there is not an established facies model for braided fluvial environments (Walker and Cant, 1984), there have been important studies of ancient braided river deposits that show their facies diversity (Moody-Stewart, 1966; Kelling, 1968; Conaghan and Jones, 1975; Campbell, 1976; Cant and Walker, 1976; Miall, 1977b; Allen, 1983; Haszeldine, 1983). However, idealized vertical sections from these studies, such as Miall’s (1977a, 1977c) proposed South Saskatchewan type, exhibit common trends in deposits that are also observed in the Burro Canyon Formation (Figure 8). As discussed previously, channel-top or vertical-accretion deposits tend to be fine-grained sandstones and claystones that overlie in-channel sandstones and are rarely preserved in braided-channel deposits (Walker and Cant, 1984). These fine-grained deposits are absent in this outcrop, and their scarcity in relation to the amount of in-channel sandstone supports the interpretation that the formation represents braided-fluvial deposits (Walker and Cant, 1984). Channel-floor coarse-grained lag deposits overlying scour surfaces are common in this environment at the base of the amalgamated channel complex (Miall, 1977b; Walker and Cant, 1984; Nichols, 2009). Several types of braid bars are present and are identifiable by their stratification types (Table 5) (Miall, 1977a, 1977b). These bars migrate and aggrade to create thick and highly variable complexes of cross-stratified sandstone. The crossbeds tend to fine and thin upward because of the decreasing flow-strength, as the bars build and the channel shal-

![Figure 17. Histograms of fluid-flow simulation results for all model scenarios (1–3), grid sizes, and upscaling methods. (a) Model 1 BTT (in months) and recovery efficiency at BTT (%), (c) model 2 BTT and (d) recovery efficiency, and (e) model 3 BTT and (f) recovery efficiency. The grid size is in meters and is indicated by $2 \times 2$, $4 \times 4$, and $8 \times 8$. Simulations that contained permeability models that were upscaled using the harmonic mean are in dark gray, geometric mean are in light gray, and uniform-petrophysical models are in medium gray.](https://library.seg.org/)
The migration and amalgamation of in-channel sandstones results in laterally extensive sandstone sheets in braided-fluvial environments (Nichols, 2009). Amalgamated channel deposits of the Burro Canyon Formation in the study area typically extend past the outcrop boundaries. Floodplain facies form thick mudstones between channels. They typically do not fully encase the channel sandstones laterally except for architectural element 3. Isolated channels are indicative of a lowering of system energy causing an increase in channel sinuosity and lower net-to-gross ratios in the Burro Canyon Formation through time.

**Effect of sandstone-body geometry and internal heterogeneity on reservoir performance**

Within a fluvial reservoir, sandstone-body geometry varies laterally and vertically between amalgamated and isolated elements depending on the energy of the depositional system. Facies associations 2 and 3 are often disconnected or in limited fluid communication with other reservoir bodies creating isolated to semi-isolated reservoir compartments, which affects recovery efficiency. As observed in the reservoir models, it is possible for isolated reservoir bodies to be penetrated by either the injector or the producer well, which impacts oil and gas recovery (Figure 14). It is important to consider these disconnected reservoirs for well planning and when interpreting well logs, in which the lateral extents of sandstone bodies are difficult to ascertain. Recovery efficiency can be increased in fluvial reservoirs containing isolated sandstone bodies, if the appropriate well geometry or spacing is used to contact multiple reservoir compartments in low net-to-gross systems.

Internal facies and architectural element heterogeneity can be an important control on the degree of fluid fingering within the reservoir, which affects the recovery efficiency. Within the amalgamated channel complex (architectural element 1), the facies associations in model 3 imposed by the channel geometry are the most important controls on fluid-flow pathways. The channel geometry aligns high-porosity and -permeability zones such that fluid is able to flow through these areas to the producing well faster than in the model 2 scenario (Figure 16). Model 3 scenarios have approximately 1.8% shorter BTT than model 2 scenarios on average; however, model 3 scenarios show a 10% decrease in the average recovery efficiency at BTT and approximately 7.5% decrease in average volumetric sweep efficiency from model 2 scenarios. This is largely because of less injected water penetrating lower reservoirs in model 3 scenarios, but also because of model 2 having less tortuous pathways for fluid to follow because it does not contain channel-bounding surfaces, which directly flow through the models. As discussed previously, it is possible for mudstone-rich channel-top deposits to be preserved on sandy-bar deposits. Because of their poor reservoir properties, these deposits could act as fluid baffles and control flow across the reservoir, thus affecting the recovery efficiency and BTT. In addition, the isolated reservoir compartments in the upper portions of model 3 are populated with fining-upward sandstones and, because of their low porosity and permeability, further prevent complete sweep of fluids through these bodies. So it is very important when mapping fluvial reservoirs to accurately identify and correlate muddy channel-top (Robinson and McCabe, 1997) and fining-upward sandstone facies when present to ensure the most accurate predictions of fluid movement, recovery efficiency, and volumetric sweep efficiency.

The reservoir models used in the flow simulations in this study are considered 2D, and because of this, flow is examined in a perpendicular direction to original paleocurrent. Dodge et al. (1971) and Jones et al. (1987) show that sandstones with unimodal cross-bedding dip, which are found in channel-fill elements of the Burro Cav...
Implications of upscaling geologic models

The most important factors when considering the degree of upscaling required to perform fluid-flow simulations are the expected impact of small-scale heterogeneity on fluid flow, time available for simulation performance and computational power of computers available, and methods used for upscaling. Many times, small-scale features can impact fluid flow and are important variables in the modeling process that should not be left out because of larger cell size. As seen in this study, grid resolution and upscaling method can have significant impacts on BTT. Increasing cell size results in longer average BTT by 40% when increasing cell size from $2 \times 2$ m ($6.5 \times 6.5$ ft) to $8 \times 8$ m ($26.2 \times 26.2$ ft), and a 17% increase in BTT is observed when the geometric mean is used to upscale permeability models compared with those using the harmonic mean. The volumetric sweep efficiency is decreased by 9% when the cell size is decreased to a $2 \times 2$ grid scenario from an $8 \times 8$ grid scenario and shows an average of 10% decrease between scenarios using the geometric mean and those using the harmonic mean for upscaling model parameters. As Salazar and Villa (2007) report, the degree of upscaling required is the critical factor in obtaining reliable future predictions. Upscaled cases need to accurately represent the original small-scale geologic model to obtain the best results. In addition, regardless of upscaling method, the original permeability field will always be changed. So, consideration should be taken for determining the most appropriate method for each project; however, the degree of upscaling is the most prominent aspect. Observed production values can potentially be inconsistent with modeled values because of these variables; therefore, significant consideration should be placed on the degree of upscaling required for the preservation of important geologic features in the model.

Conclusion

The Burro Canyon Formation represents low-sinuosity braided fluvial deposits at the base that transition upward into sinuous-fluvial deposits. Four main architectural elements are observed, three of which exhibit high reservoir quality: amalgamated channel complexes, amalgamated fluvial-bar channel-fill deposits, isolated fluvial-bar channel-fill deposits, and floodplain deposits. The amalgamated channel complex forms the best reservoir zone because of its thickness, lateral extent, and high-reservoir-quality lithofacies and associated petrophysical values. The low vertical and lateral connectivity of the amalgamated fluvial-bar channel-fill deposits and isolated fluvial-bar channel-fill deposits typically reduces or completely prevents fluid communication between them creating separate reservoir compartments. These architectural elements are completely encased in floodplain deposits.

The 2D reservoir modeling and fluid-flow simulation results show how internal facies heterogeneity of reservoir bodies impacts fluid flow. The BTT varies by almost 50% because of the lithofacies variability from the model 1 (shortest) to the model 2 (longest) scenarios. When channel bounding surfaces are modeled in the amalgamated channel complex, as in model 3, the concave-up curvature associated with them forces fluid through channel-fill elements along different paths than
in models without internal bounding. This generally decreases the volumetric sweep and recovery efficiency by an average of 8% and 10%, respectively, in more complex model simulations. However, the channel bases preferentially align lithofacies with high porosity and permeability, creating pathways for flow and decreasing average BTT by approximately 2% as compared with model 2 scenarios and increasing average BTT by 23% from model 1 scenarios.

Fluid-flow studies on varying grid resolution (cell size) indicate a significant effect on BTT. Increasing cell size results in longer average BTT by 40% from 2 × 2 grid to 8 × 8 grid scenarios. The method used for upsampling permeability models is also important. Model parameters that are upscaled using the geometric versus harmonic mean preserve slightly higher ranges of permeability, and this results in longer average BTT by 17%. Volumetric sweep efficiency is affected by the cell size and the upsampling method. There is an average of 9% decrease in values between grid scenarios with the highest (8 × 8 grids) and the lowest (2 × 2 grids) recovery efficiencies and an average of 10% decrease between models using the geometric mean and those using the harmonic mean for upsampling. Recovery efficiency does not vary significantly with grid resolution, in which there is approximately a 3% difference between the highest average recovery efficiencies at BTT in the 8 × 8 grids and the lowest in the 2 × 2 grids. The recovery efficiency is also relatively unchanged between upsampling methods with a 3% difference on average.

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Data and materials availability
Data associated with this research are available and can be obtained by contacting the corresponding author.

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