STRATIGRAPHY AND POROSITY MODELING OF SOUTHERN CENTRAL ILLINOIS CHESTER (UPPER MISSISSIPPIAN) SERIES SANDSTONES IN PETREL

Darren Kimple

84 pages May 2012

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This thesis reports the results of a stratigraphy and porosity modeling project that used Petrel to analyze the additional production potential of Chester series sandstones at the Loudon Anticline. The project involved the construction of three-dimensional (3D) models in Petrel 2010 (Schlumberger) of the facies and porosity of Chesterian-age strata in the Loudon Oilfield. The porosity model depicts porosity conditions of the reservoir sandstones of the Cypress, Paint Creek, Yankeetown, and Aux Vases formations. The facies model defines the three major facies in the area: sandstone, shale, and carbonate. Both models were built using digitized logs collected from eleven saltwater injection wells and two producing wells. The values assigned to each model grid cell were based on the density porosity log and the gamma ray log of the wells. Various modeling parameters including grid cell size, boundary locations, and algorithm were evaluated to ensure the most accurate models possible. Upon completion of the models, the facies model was used to delineate the stratigraphy of the area. The porosity model was compared to the facies model to determine the degree of accuracy by which the porosity

model depicted the location of porous sandstone. Using the facies model and net sand isopach maps potential production and injection targets were analyzed. Nine prospective areas for new wells (eight production, one injection) were determined.

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DARREN KIMPLE

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DARREN KIMPLE

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CONTENTS

TABLES

FIGURES

I. INTRODUCTION/BACKGROUND

Porosity is a controlling factor in the ability of a rock body to store fluid. Greater porosity equates to greater space for fluids, i.e. water, gas, and oil, to accumulate. Coupled with permeability the porosity of a rock body is important to the petroleum industry. Oil companies want to locate the rocks with high porosity and permeability. Well logs displaying the porosity values for the rock units of a newly drilled well are generated by a logging tool recording within the wellbore. Subsequently, a porosity log can be correlated to porosity logs from other wells via modeling software with the goal of constructing an interpretive model. The resulting model illustrates the porosity of the geologic formations found in a particular area.

Gamma ray logs are used to identify rocks high in clay content. Higher gamma ray count equates to higher clay content. The situation exists where a rock body may have high porosity on a log and have increased clay present. Though a rock unit may have high porosity, the presence of high amounts of shale can equate to low permeability. These two logs were used to construct the porosity model and the facies model of the Loudon Oilfield Chesterian-age rock units. The spontaneous potential tool measures natural electric potentials present in boreholes and is commonly used to distinguish porous, permeable sandstones (Rider, 1996). Spontaneous potential logs were used to assign tops and bases and to calculate net sand thicknesses of the four main sandstones in and around

the study area.

Open-hole well logs have been utilized in countless exploration and production projects to successfully predict reservoir quality with respect to porosity (Atchley *et al.*, 2010). Wireline logs along with core samples were used by Byrnes (2008) to analyze lithofacies sedimentary characteristics of the Mesaverde Group tight gas sandstones in numerous western U.S. basins. In another related analysis, Xu *et al.* (2009) used borehole images (12 wells) and open-hole logs from numerous (~500) wells located at the Red Oak Gasfield of southeastern Oklahoma to investigate the structural and sedimentary characteristics of the lower Pennsylvanian Red Oak Sandstone of the Arkoma basin in an effort to better understand the behavior of this unit as a hydrocarbon reservoir. The images along with the logs, which included neutron, density, gamma ray, array induction resistivity, and sonic, were used to correlate formations and to map the geology of the field.

The Loudon Oilfield (Figure 1), located in Fayette County, Illinois, occupies ~50 mi^2 and contains nearly 2000 (active injection and production) of the approximately 90,000 wells that penetrate the New Albany (source rock) petroleum system throughout the Illinois Basin (Lewan, 2002) (Figure 2). More than 4 billion barrels of oil have been produced from Paleozoic strata in the Illinois Basin (Bethke *et al*., 1991), with an estimated 400 million barrels recovered from Loudon (Finley, 2006). The field is a northeast trending anticline with 165 feet of structural closure and 1° to 2° flank dips (Harris, 1975). There are four main oil and gas-bearing sandstone units within the field. All are Chesterian (Upper Mississippian) in age. From youngest to oldest the sandstones

are the Weiler, Paint Creek, Bethel, and Aux Vases (Figure 3). These sandstones were deposited in a fluvial deltaic setting (Nelson *et al.*, 2002). During the lower Chesterian

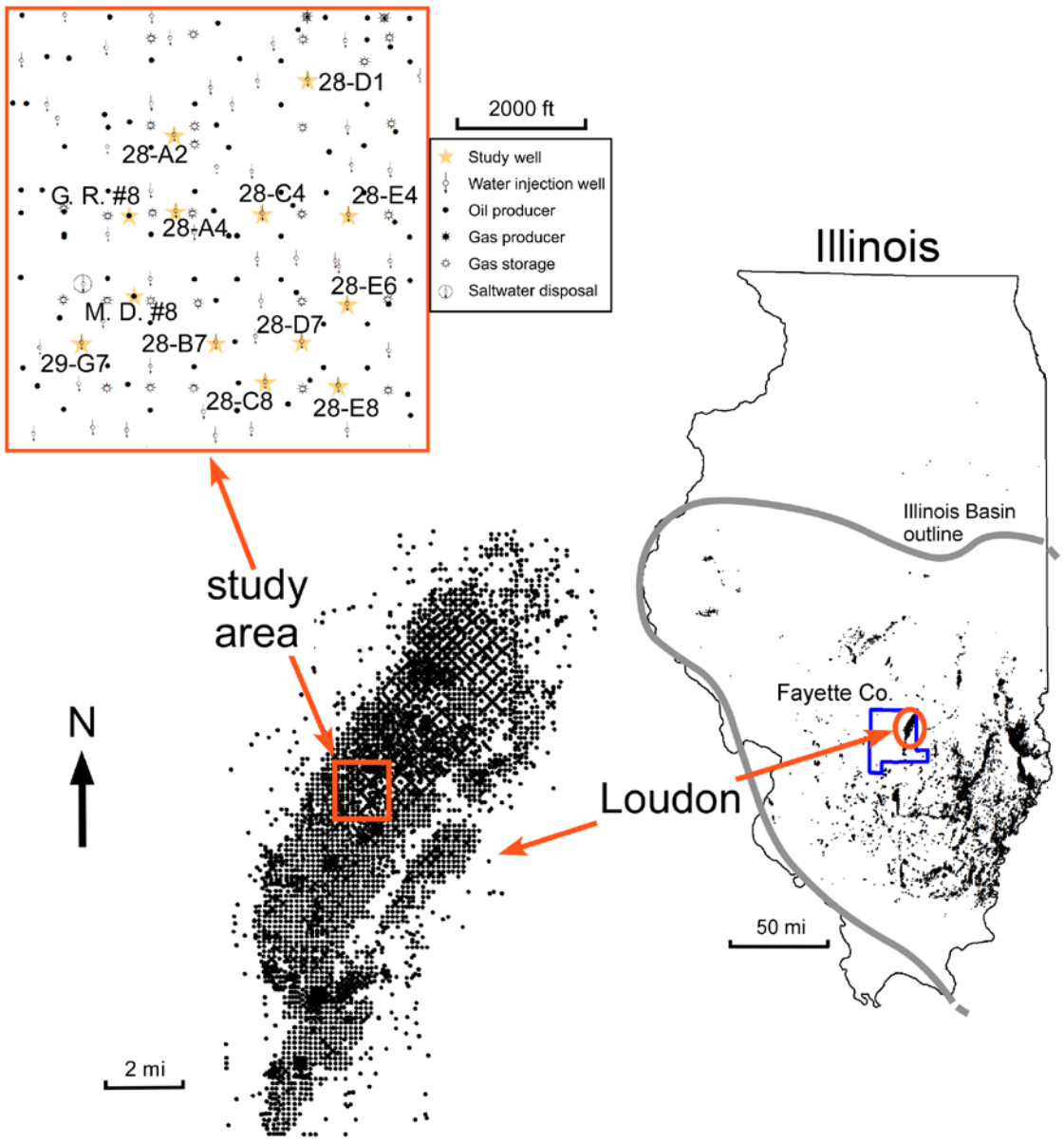

Figure 1: Oil and gas production and water injection wells in Illinois and study site including locations of 11 injection wells and two production wells with LAS files (basin outline modified from *ILDNR, 2011*)

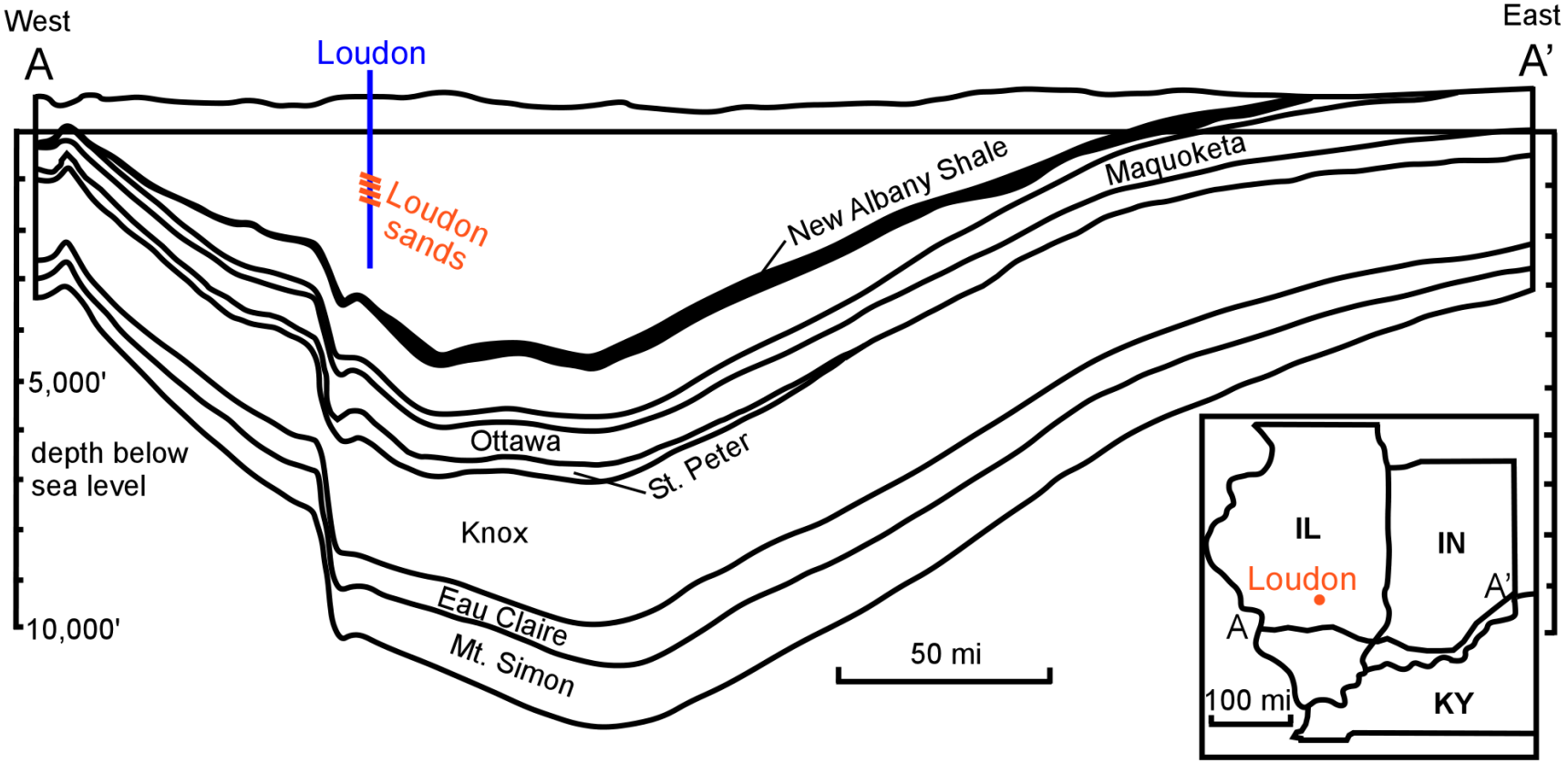

Figure 2: Cross section of the Illinois Basin (modified from *Bell et al., 1964*), inset shows the location of line of cross section A-A' and Loudon Oilfield

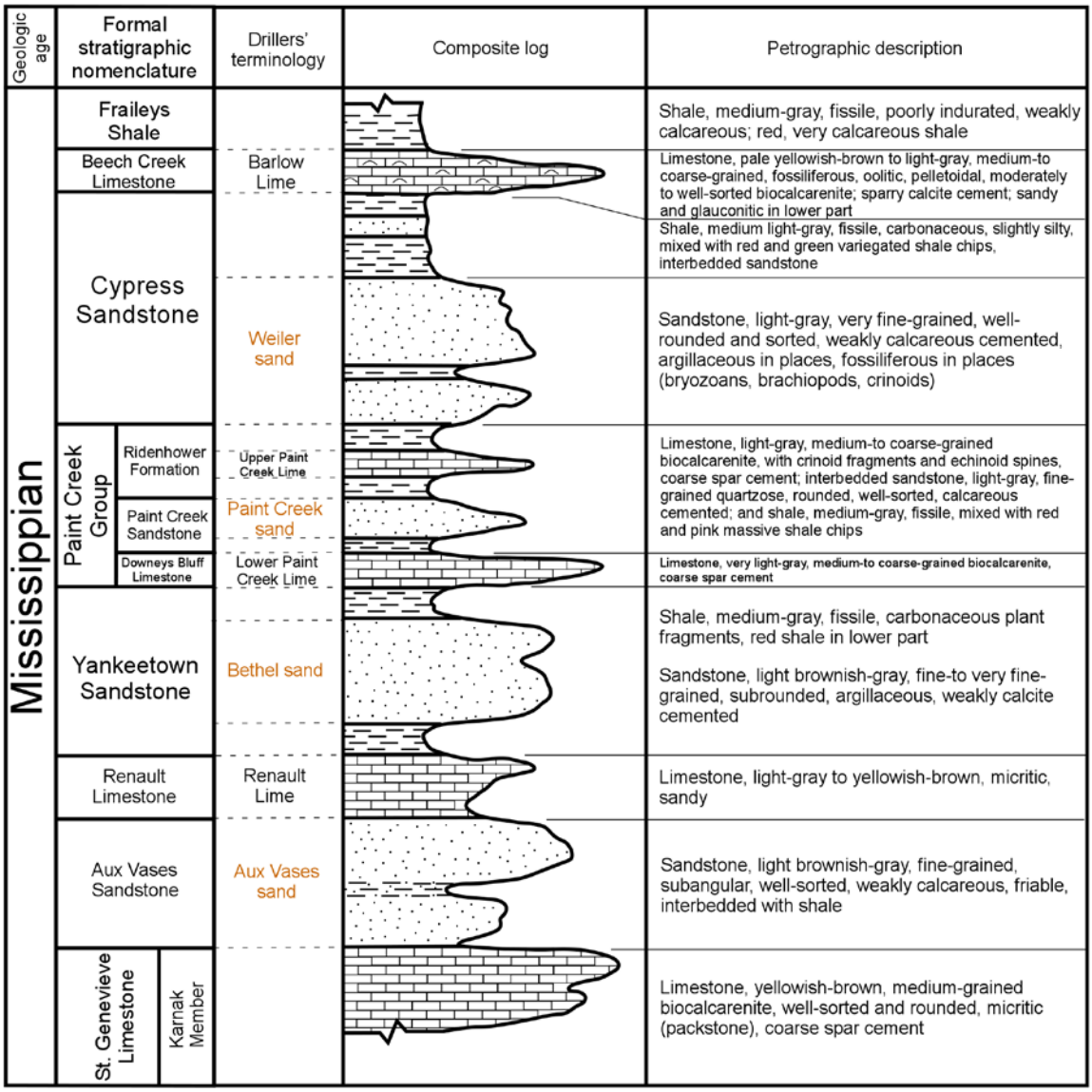

Figure 3: Stratigraphic column including petrographic description of Upper Mississippian rocks in southern central Illinois (modified from *Cluff and Lasemi, 1980*), drillers' terminology describes subunits within larger formations

the Illinois Basin lay in the tropics between 5° and 15° south of the equator and was a shallow marine platform or ramp and at times an embayment open to the south (Craig and Connor, 1979). The region was a flat coastal plain during lowstands. Sand deposits

formed elongate tidal bars and channel sands, explaining the pinching out nature of the present day rock units. Sediment grain size analysis and distribution patterns and paleocurrent structures indicate that Weiler and Paint Creek sands came from a northeastern source, Bethel sands were sourced from east of the basin, and Aux Vases sands were sourced from the Transcontinental Arch, northwest of the Illinois basin (Nelson *et al.*, 2002). In the Loudon Oilfield the Aux Vases sandstone has as a blanket geometry, and the Weiler, Paint Creek, and Bethel sandstones are discontinuous (pinch out). The Weiler sandstone ranges from 0-60 ft in thickness (Cluff and Lasemi, 1980). The Paint Creek thickness ranges from 0-40 ft. The Bethel sandstone ranges from 0-40 ft in thickness. The Aux Vases thickness ranges between 60-80 ft. Average porosity of the Weiler sandstone is ~20% (Mast, 1970). The other three sandstones have an average porosity of ~18%. The horizontal permeability value for all four sandstones is ~100 milli-darcies (md).

Waterflooding has been used to enhance oil recovery efforts at Loudon for several decades. In waterflooding, formation water produced during oil recovery is used to sweep the sandstone reservoirs of additional oil. The process involves the use of high pressure, high volume pumps to force saltwater down a well and into a rock unit via the perforations of the well casing. The water then travels through the rock body until being drawn into a nearby production well, which subsequently pumps the fluid (water and oil) to the surface. Approximately 150 new injection wells have been drilled in the last two years at Loudon with an estimated 100 to 200 more planned to be drilled in the next two years. New production wells are being drilled in response to the influx in reservoir fluid

caused by the recent waterflooding efforts and to explore untapped areas of the field.

The array of stratigraphic complexities at the Loudon Oilfield makes correlation and fluid dynamics complex and challenging. Sandstones 30-40 ft in thickness have been seen in well logs to taper and eventually pinch out in a few hundred feet. An accurate representation of the stratigraphy is vital to production efforts. A 3D facies model built in Petrel of the Chesterian rocks at Loudon, which has never been built before, would aid in the location and geometry estimation of the various shales, sandstones, and limestones present at Loudon.

The main goal of this project was to locate additional areas at the Loudon Oilfield suitable for oil recovery processes (injection or production). This goal was to be accomplished by two methods. One method involved creating a 3D model depicting the facies of rocks of the Loudon anticline based upon values obtained from digitized wireline logs. All rock units (sandstones, shales, and carbonates) from ~800-1000 ft below sea level were delineated, particularly four sandstones: (youngest to oldest)

- Weiler
- Paint Creek
- Bethel
- Aux Vases

Using the facies model and a Loudon field map, sandstone strata were analyzed for additional production targets based on sand thicknesses predicted by the model and by location relative to lease lines and existing wells. The second method involved creating isopach maps based on net sand thicknesses calculated from spontaneous potential logs.

The sand thicknesses and location relative to lease lines and existing wells determined the prospective production and injection well locations. The results of the two methods were compared to each other. Locations for eight production wells and one injection well were determined from both methods.

A secondary goal of this project was to determine the ability of a porosity model to predict sandstone facies. A porosity model was built using similar methods as in the building of the facies model, and a subsequent model was built that compared the porosity model to the facies model. The comparison model provided the degree of precision by which the porosity model indicated sandstone facies.

II. METHODOLOGY

Various methodologies (induction, neutron, etc.) are used in the wireline logging process at Loudon. One of these, the density log tool, measures formation density by bombarding the rock with gamma rays (photons) and then measuring the amount of gamma rays that return to a counter (Rider, 1996). As the photons collide with the electrons in the formation, the gamma ray loses energy to the electron (Compton scattering). The denser the formation, more electrons are present, and more energy is lost due to collisions. Rocks with higher porosity will allow more gamma rays to pass through and return to the counter. After mathematical processing the data obtained from the density log tool establish a density porosity log. The equation used is:

$$\Phi = \rho_{ma} - \rho_b / \rho_{ma} - \rho_{fl}$$

where Φ is the porosity, ρ_{ma} is the rock matrix density, ρ_b is the bulk density (from density log), and ρ_{fl} is the fluid density (often assumed to be density of mud filtrate). Limestones and shales tend to have lower porosity values compared to sandstones. The gamma ray logging tool measures the level of naturally occurring radiation (U, T, K)in rock bodies. Among sediments, shales possess by far the highest level of radiation, making the gamma ray log a suitable representation of a rock body's shale content (and permeability). Limestones tend to have roughly the same gamma ray values as sandstones. All three rock types (shale, limestone, sandstone) can be distinguishable from

the gamma ray log. Spontaneous potential logging tools measure small electric potentials (in millivolts) between depths in the borehole and a grounded voltage located at ground surface. A buildup of charge on the wellbore walls instigates the change in voltage through the wellbore. Low permeability rocks such as shales and permeable sandstones generate differing charges. All three rock types (shale, sandstone, limestone) are distinguishable on spontaneous potential logs.

The 3D facies model and porosity model were built in a similar manner in Petrel, the main difference being the type of log used to populate the grid cells (discussed below). In deciding which wells to use in the models, the size of the model domain needed to be established. If too large an area was chosen, then there would be more space in between each well and less data control from the well logs, which could possibly correlate to less accurate models. This is especially true at Loudon where the sandstone reservoir rocks are notorious for abrupt facies and porosity pinchouts and overall erratic thickness variations due to their channel sand deposition (Montgomery and Leetaru, 2000). A smaller area would yield a smaller but more detailed model. Due to a limited number of available digitized well logs, an area measuring ~1 mi^2 was chosen using thirteen wells, eleven injectors and two producers (Figure 1). Eight Log ASCII Standard (LAS) formatted files (digitized logs) were obtained from the GEOLOG logging company that included the results from all logs created, particularly the density porosity log and gamma ray log for eight injection wells drilled at Loudon from 2010 to 2011. Five additional well logs (three injectors and two producers) were digitized from paper logs to LAS format using NeuraLog (NeuraLog, 2011). Depths of the eight wells vary in

a range of 1603-1710 ft below ground surface. One of the eight wells (29-G7) was significantly shallower, being drilled to a depth just below the Bethel sand. The other 12 wells were drilled through the Aux Vases sand. A more complete study of this kind would include cores and seismic data.

Facies model methodology

Overview of model construction

The facies model, porosity model, and facies/porosity comparison model are made up of cells enclosed in a 3-dimensional grid (~300 rows, ~300 columns, and ~200 layers) consisting of vertical boundaries (horizons representing tops and bases of rock units) and a horizontal boundary which signifies the xy limit of the surface boundaries. The top and base of each of the four sandstones and the Barlow limestone were manually picked from the thirteen digitized logs (porosity and gamma ray) and combined with the tops and bases picked from paper logs (spontaneous potential logs, no available porosity and gamma ray logs) of the 70+ surrounding wells to create an Excel database to be used in making surfaces and model boundaries. Grid cell size (20x20x1 ft), boundary locations (horizontal and vertical), and a modeling algorithm (Gaussian) were chosen, and 3D grid cells were assigned facies and porosity values (depending on which model) based upon these three parameters and the porosity and facies values from the thirteen digitized well logs.

Well tops/xy boundary/surfaces

In Petrel, the well data including name, geographic location (UTM), kelly bushing elevation, and total well depth were loaded. Figure 4 displays the location of the wells within the study area. The LAS files were then imported and assigned to their respective wells. A new 'well section' window was opened and logs from all 13 wells were displayed horizontally (Figure 5). The tops and bases of the four main sandstone units in

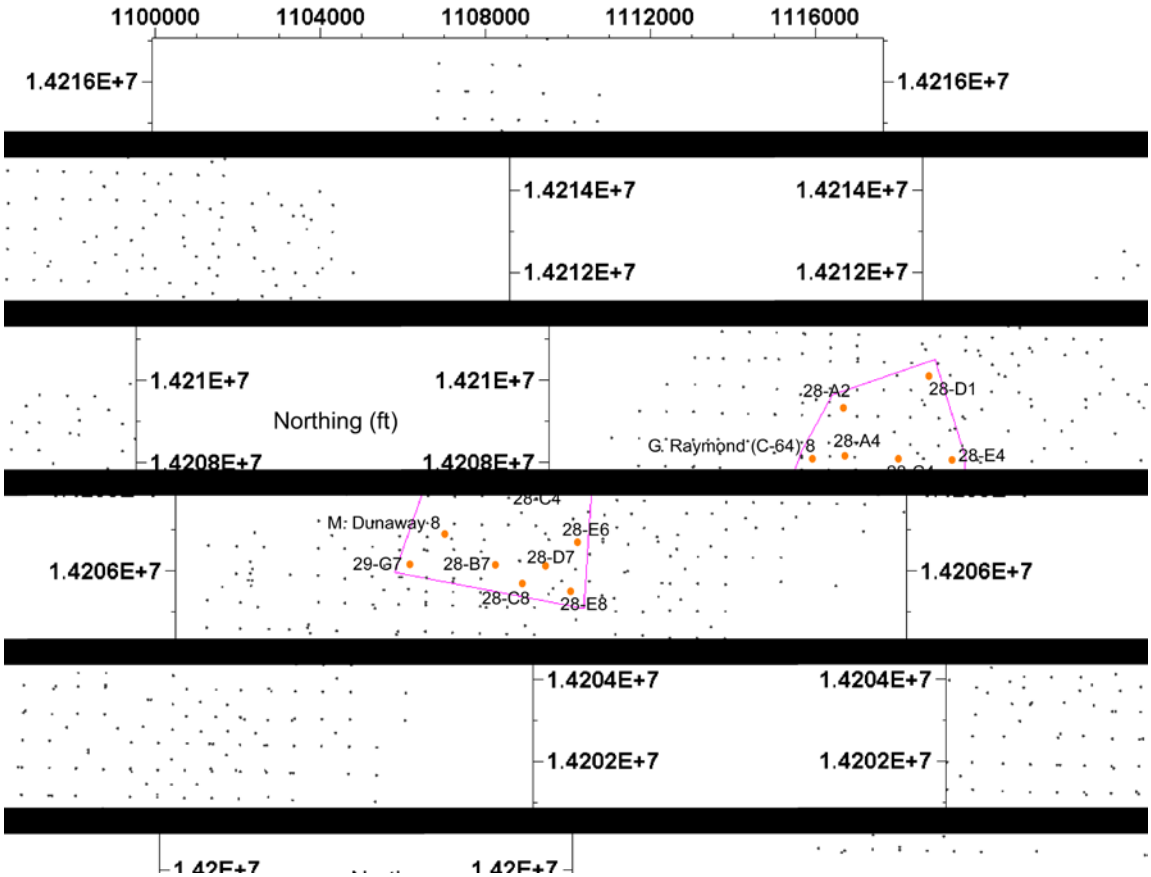

Figure 4: 13 well study area enclosed by xy boundary polygon (pink)

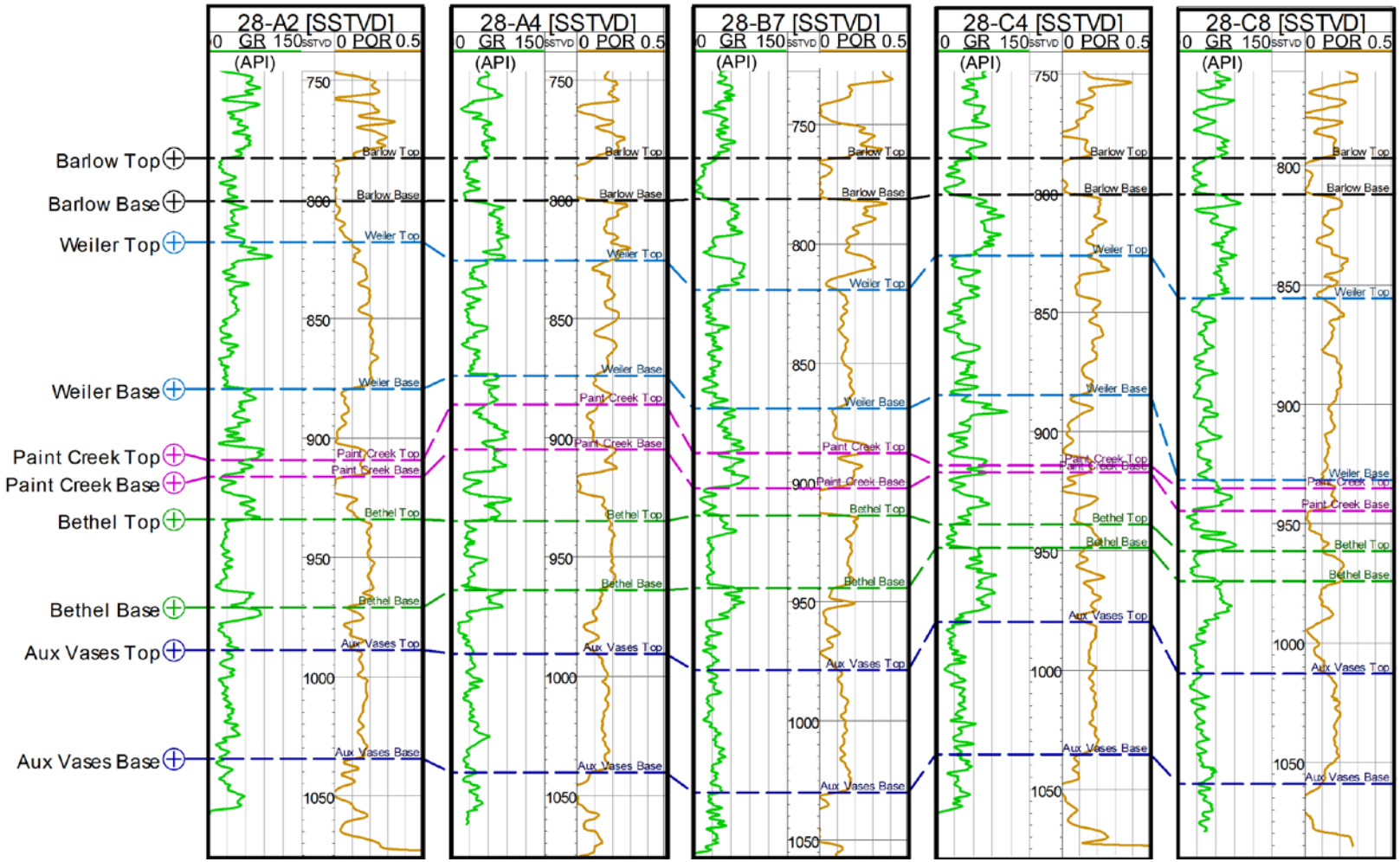

Figure 5: Porosity and gamma ray logs of the 13 study area wells, dashed lines show picked well tops, green line = gamma ray log (API units), brown line = porosity log, SSTVD = sub-sea total vertical depth (ft)

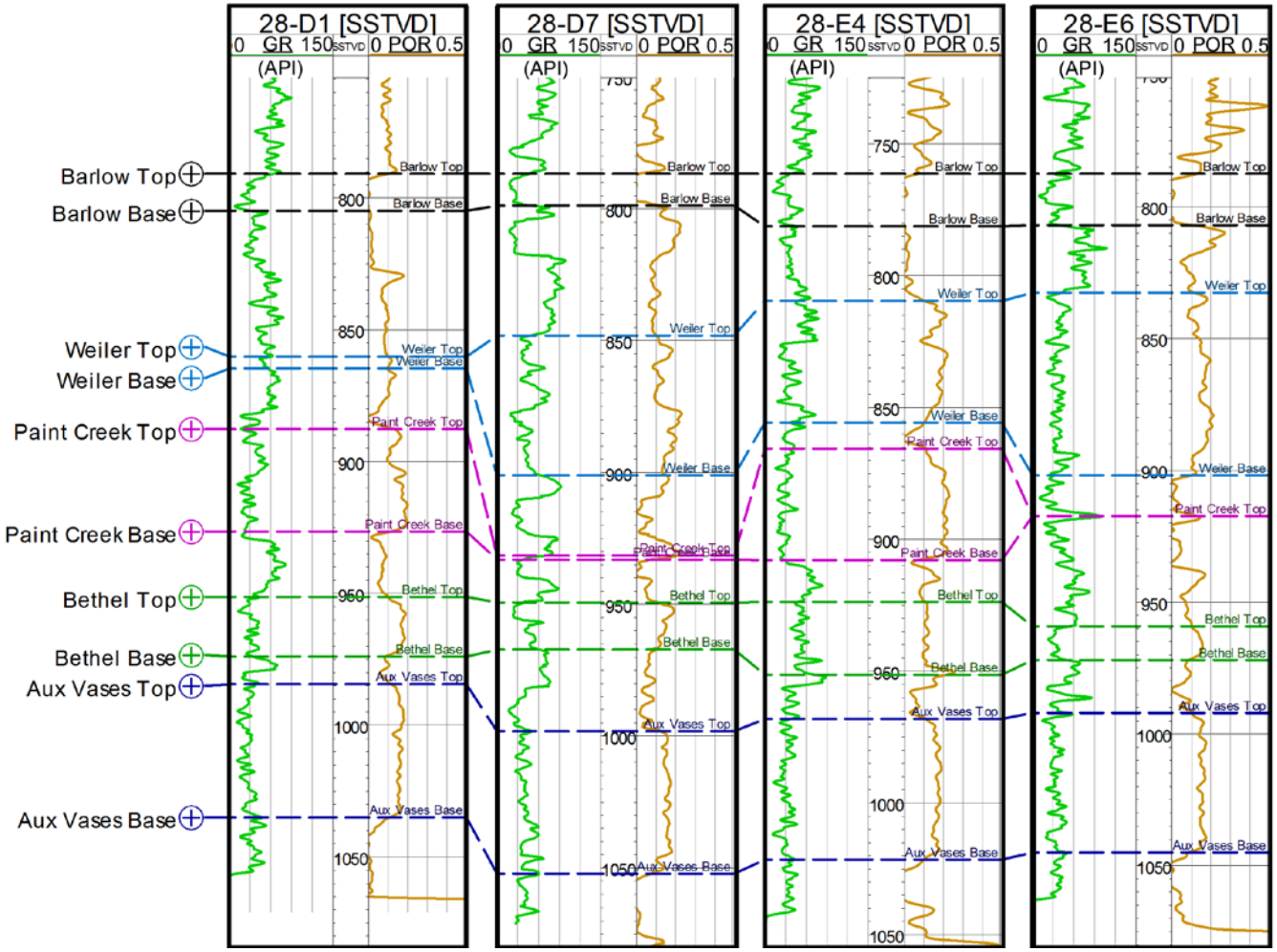

Figure 5 (cont'd): Porosity and gamma ray logs of the 13 study area wells, dashed lines show picked well tops

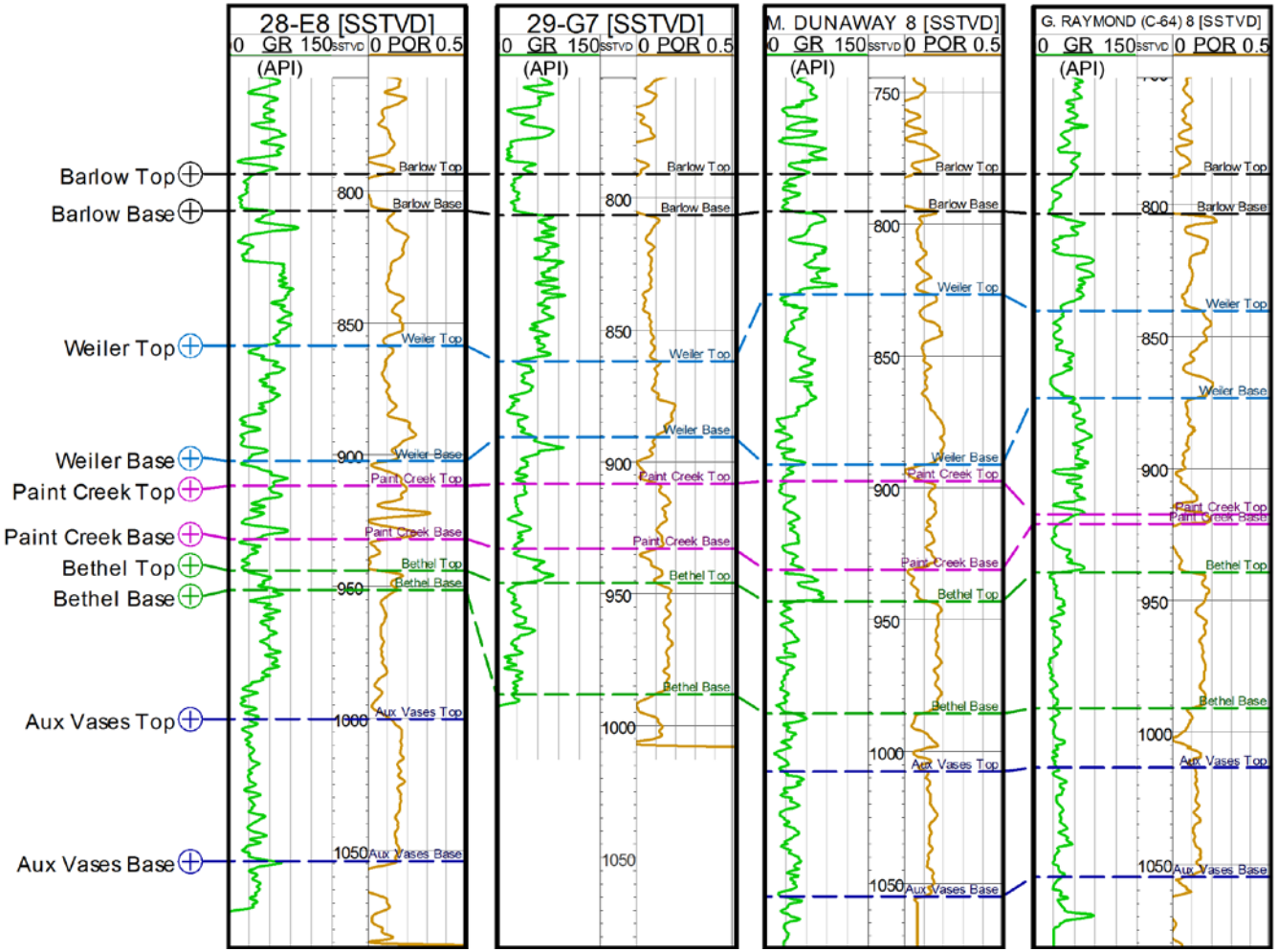

Figure 5 (cont'd): Porosity and gamma ray logs of the 13 study area wells, dashed lines show picked well tops

all 13 logs were then manually picked and assigned to their respective rock layer horizon (top or base). Tops and bases were based on gross sand intervals, meaning at least the top and bottom portions of the interval consisted of favorably (greater than 10% porosity) porous sand that belonged in the given sandstone zone, but shale and/or carbonate may exist in between the sand units.

In a 2D window the wellspots for the 13 wells were displayed. A polygon was then created that enclosed the 13 wells (Figure 4). The polygon was made to extend a short distance passed the outermost wells. Since no log data exists beyond the outermost wells, model values were assumed to become more inaccurate with distance from the study area, so the distance from the outermost wells to the xy limit was made small (~200 ft). Surfaces to be used in creating vertical boundaries for the model were built using the well tops and the xy polygon. The well tops from each well were connected with the xy boundary polygon defining the outer limits of the surfaces. A top and base were created for the Barlow limestone and each of the four main sandstones (Weiler, Paint Creek, Bethel, Aux Vases).

3D Grids/Layering

Surfaces were used as vertical (z) boundaries in the 3D grids. Surfaces were used to ensure the geometries of the various rock units were honored. A grid based on constant elevations, e.g. a model with a top set at -800 ft and a base set at -1100 ft, would capture the area of interest, but the shapes of the rock bodies would be skewed due to cell value distribution patterns based on horizontal layering. Three varying approaches to displaying

the stratigraphy were tested when building the 3D grids. One 3D grid approach used a top model boundary as the top of the Barlow limestone and a base model boundary as the base of the Aux Vases (Figure 6). This approach modeled all rock facies within the study elevation interval and to a certain degree (only based on Barlow and Aux Vases geometries) honored the true shape of the rock bodies. A second approach used gross sand top and base surfaces for the five main rock units picked from the 13 digitized well

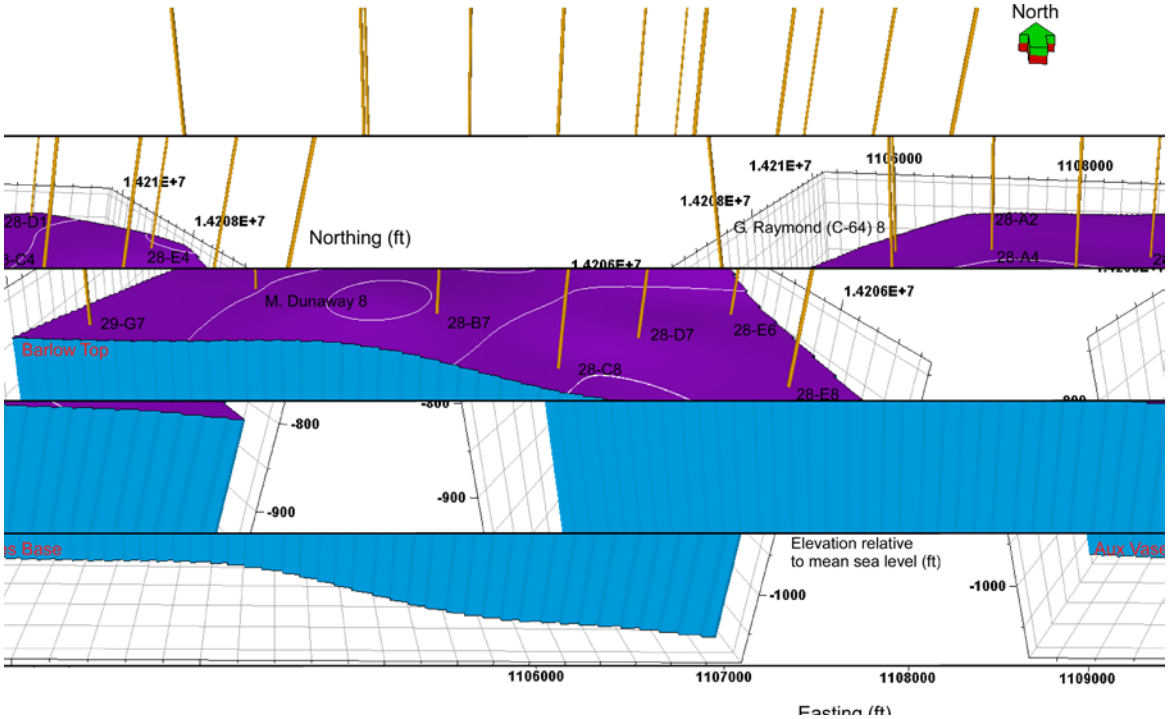

Figure 6: Non-partitioned vertical boundary scenario used in facies and porosity modeling, Barlow top and the Aux Vases base vertically bound the model

logs along with the gross sand top and base data from the ~70 surrounding wells (Figure 7). The exact number of surrounding wells included in the surface building process is uncertain. Well top data from paper logs of wells outside of the xy boundary polygon (all wells outside of polygon in Figure 5) were incorporated in the overall well top database

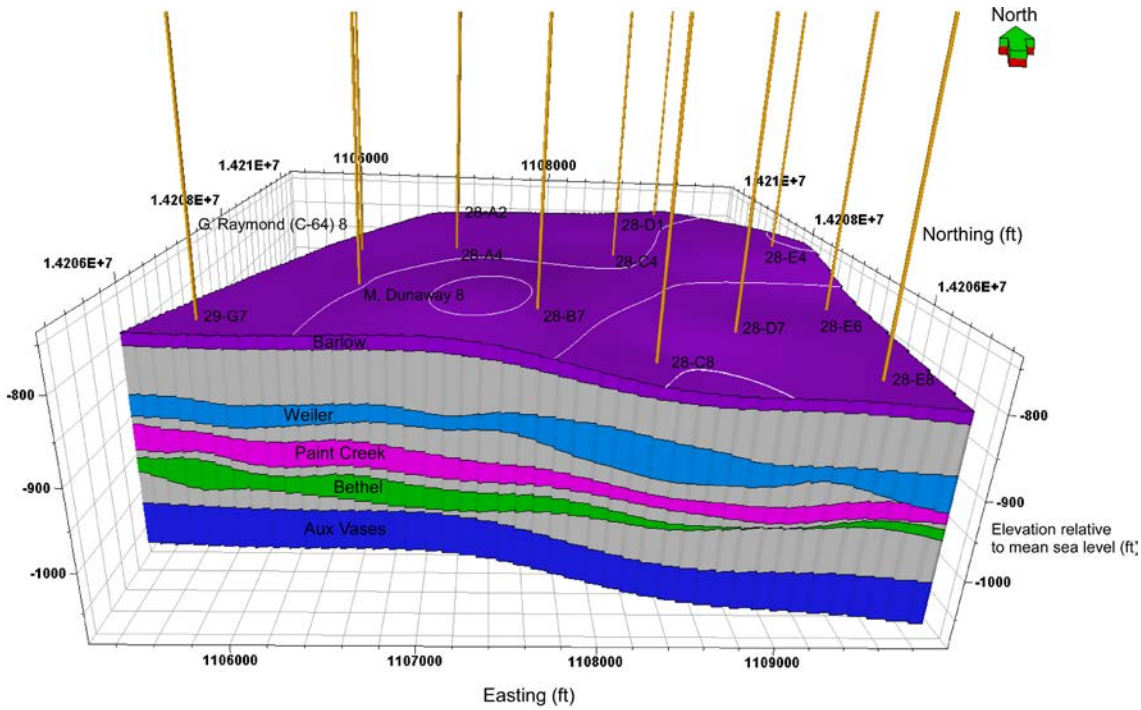

Figure 7: Sandstone surface partitioned vertical boundary scenario used in facies and porosity modeling, Barlow and four main sand surfaces vertically partition model

spreadsheet that was used to form the surfaces. Though there is a boundary polygon, Petrel will incorporate data that are outside of the polygon in making surfaces. The facies model built using the gross sandstone surfaces as interior partitions was essentially a geologic model populated with facies values. A separate 3D grid was built for each zone and combined (stacked one atop the other) to make one overall model. The zones were:

- Top of Barlow to base of Barlow (Barlow zone)
- Base of Barlow to top of Weiler
- Top of Weiler to base of Weiler (Weiler zone)
- Base of Weiler to top of Paint Creek
- Top of Paint Creek to base of Paint Creek (Paint Creek zone)

- Base of Paint Creek to top of Bethel
- Top of Bethel to base of Bethel (Bethel zone)
- Base of Bethel to top of Aux Vases
- Top of Aux Vases to base of Aux Vases (Aux Vases zone)

This approach ensured the honoring of the geometry of all the rock layers within the extent of the available rock unit top and base elevation data. A third vertical boundary modeling approach used surfaces representing midway points between the main rock units (Figure 8). The zones used were:

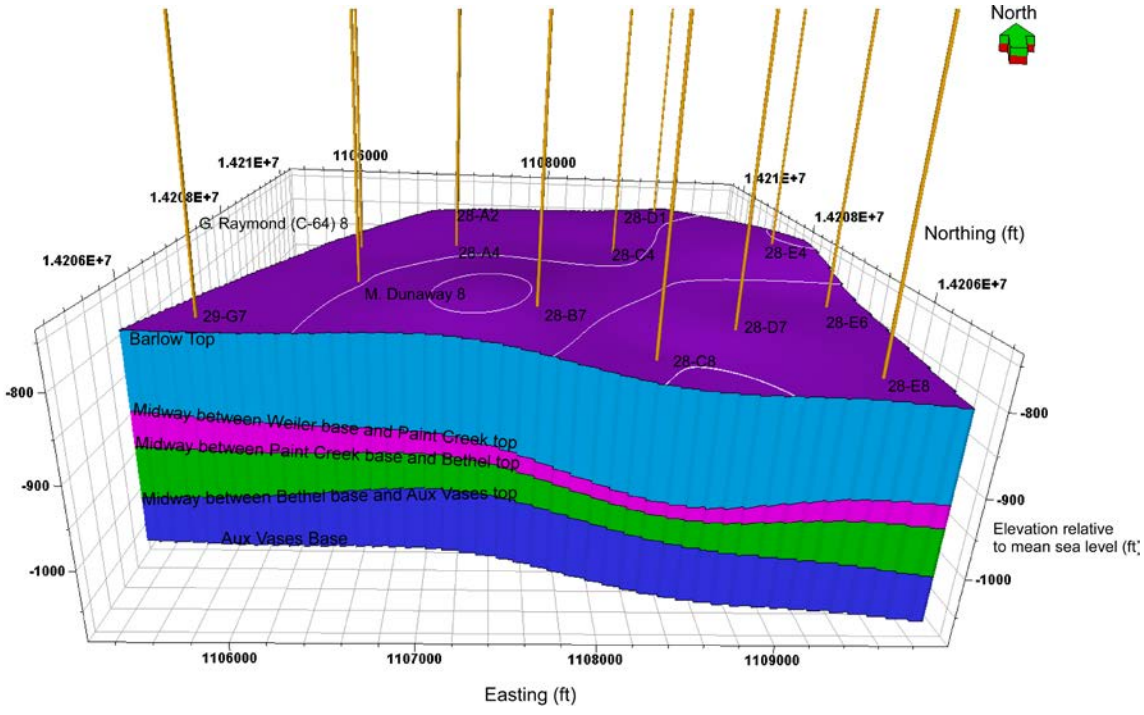

Figure 8: Zone-partitioned vertical boundary scenario used in facies and porosity modeling, surfaces midway between the four main sands vertically partition the model

- Top of the Barlow to midway between the Weiler base and the Paint Creek top (Weiler zone)

- Base of the Weiler zone to midway between the Paint Creek base and the Bethel top (Paint Creek zone)
- Base of the Paint Creek zone to midway between the Bethel base and the Aux Vases top (Bethel zone)
- Base of the Bethel zone to the Aux Vases base (Aux Vases zone)

This approach allowed facies values to be distributed laterally with fewer restraints from top and base bounding surfaces as may be the case in the second and third approaches (discussed further in results). Construction of the various models grids involved converting surfaces to grids with a designated xy cell spacing value. Grid cell dimensions for x and y were tested at 5x5 ft, 20x20 ft, and 50x50 ft. As an example, Figure 9 displays the Barlow top surface and the Aux Vases base surface, both of

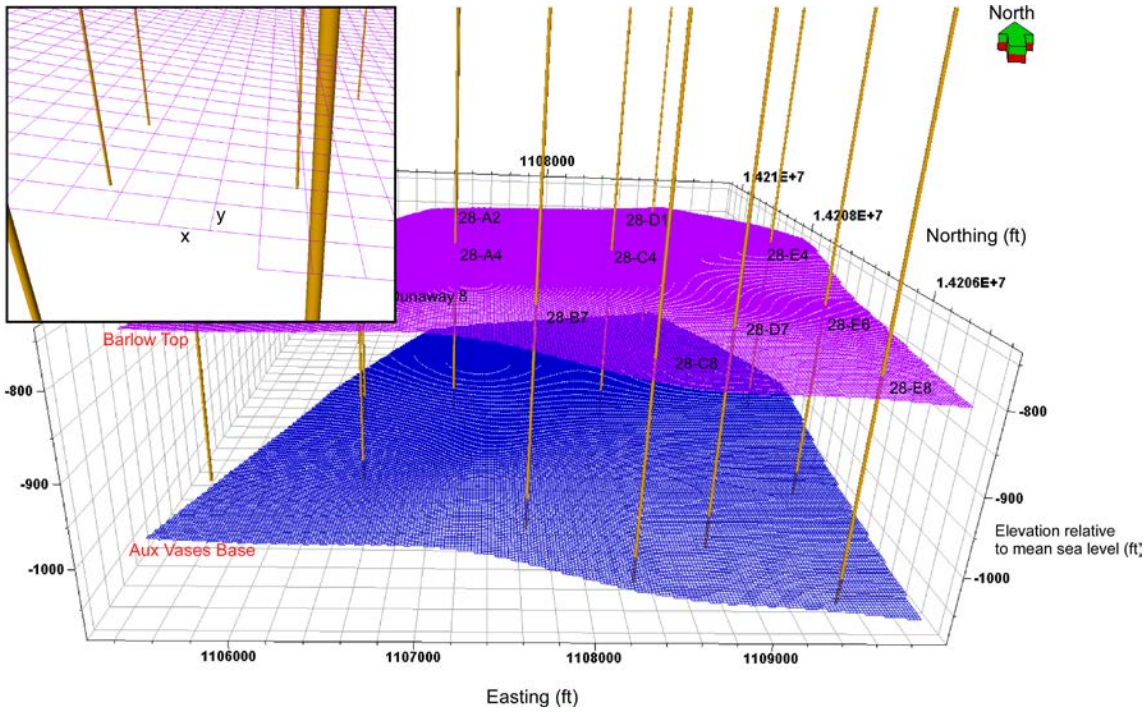

Figure 9: Example of surfaces converted to grids, inset shows xy grid cells (20x20 ft)

which were converted to grids. Models using the varying grid cell sizes are discussed further below in the results section.

Layers were assigned to each 3D grid (zone) (Figure 10). Logging devices record values continuously (no space in between values) on the log, so the smaller the z dimension (to a certain limit) of the grid cell the more log values that can be incorporated into the model and the more detailed the model. The logging tool is only accurate to a certain interval size. A one foot average layer thickness is near the limit of dependability of the tool, so the average thickness of each zone was obtained from the statistics data and used to assign the number of layers in each zone (average thickness = number of

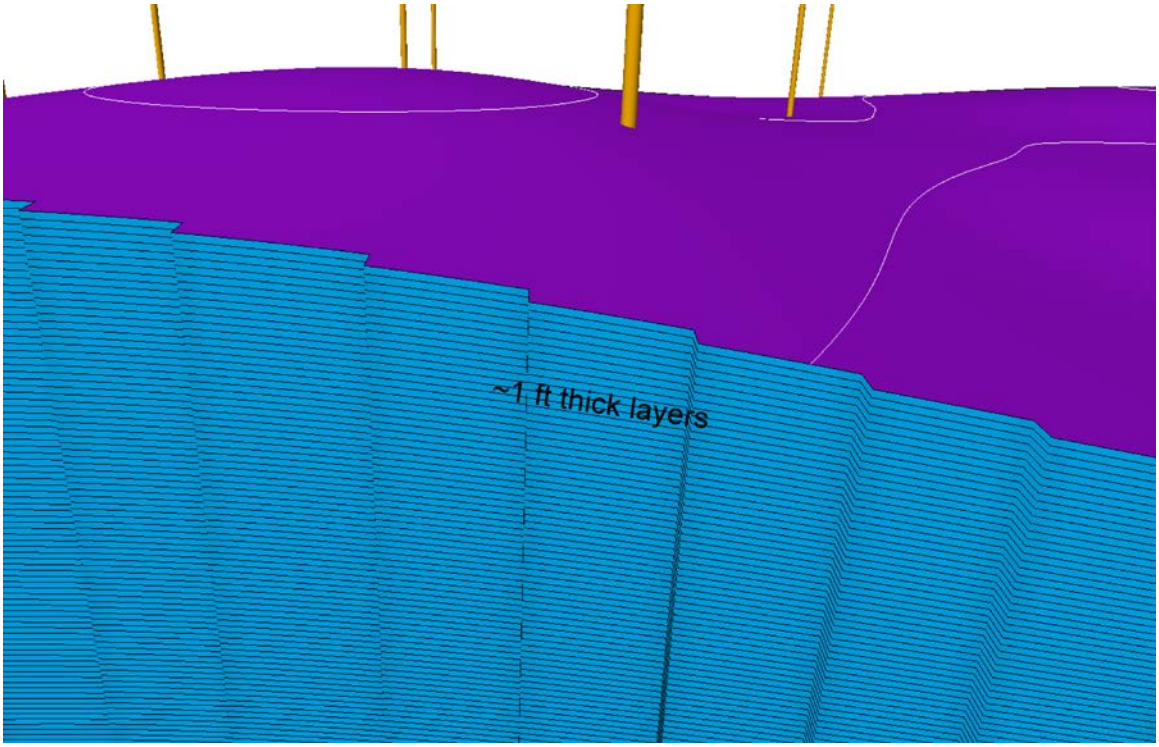

Figure 10: Up close visualization of model showing individual layering between the vertical boundaries, average layer thickness = number of layers = ~ 1 ft thick layers on average

layers = ~1 ft thick layers on average). The thickness of the layer at a given location provides the z dimension of the 3D grid cell at that location. Zones are not uniformly thick so z values of grid cells varied from location to location. Models using an average thickness of 2 ft and 5 ft were built and run to compare to the 1 ft layer model (discussed further in results).

Facies log

Using the 'log calculator' function in Petrel, a facies log was constructed that would be used to populate the 3D grid cells. In the log calculator an equation was entered that assigned three different facies types to the corresponding depth intervals of the well based upon values from the density porosity and gamma ray logs. If the porosity was greater than 0.1 and the gamma ray log value was lower than 60 API (American Petroleum Institute) units, then the interval was designated as sandstone. If the porosity was lower than 0.1 and the gamma ray log value was less than 60 API units, then the interval was designated as carbonate. If the gamma ray log value was greater than 60 API units, then the interval was assigned a shale facies designation. The limit values of 0.1 porosity and 60 API units were based on density porosity and gamma ray log values of known facies intervals (e.g. Barlow lime, Weiler sand).

Upscale well logs/Facies modeling

The upscale well logs process (Figure 11) involved creating an upscaled facies log for each of the 13 wells. The facies assigned to the layer intervals (z) of the upscaled log

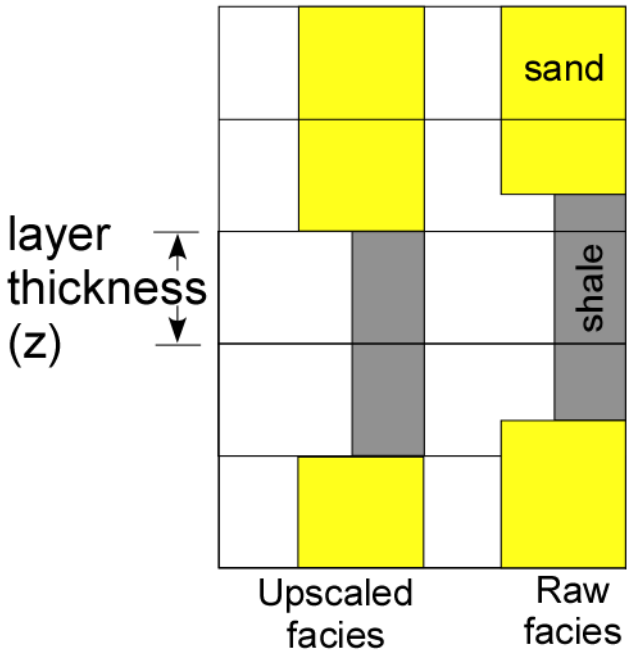

Figure 11: Example of the upscaling facies log process

were the dominate facies type found on the facies log within the thickness (z) of the layer. For example, a layer on the facies log that consisted of 60% shale and 40% sandstone received a shale classification on the upscaled facies log. The upscaled well logs were then used in the facies modeling process to assign facies types to the 3D model cells. The facies modeling process involved selecting an appropriate algorithm (two options) to run the model and setting guiding parameters (horizontal and vertical correlation ranges) for the variogram used in the algorithm. The two modeling algorithms evaluated were:

- Truncated Gaussian Simulation
- Sequential Indicator Simulation

Variograms affect the manner by which the algorithm assigns values to the model. Appropriate horizontal and vertical correlation ranges of the variogram were determined and used to run the model.

Validation of the facies model

To validate the 3D facies model two additional models were constructed. In each model one (different one for each) well's data (log and surface picks) were omitted and the model rerun. The two wells chosen for the validation models represent opposite extremes of data control. One model omitted the northern most well's data (well #28-D1). This well displayed the largest proximity from the other 12 wells in the study area and is the well baring the least control from log data. The other model omitted a well's data (well #28-D7) in the southeast corner of the study area. Relative to the other 12 wells 28-D7 is the closest in proximity and is the well with the most log data control. The zone partitioned vertical boundary scenario and a grid cell size of 20x20x1 ft was used to guide the algorithm in assigning cell values. The zone partitioned vertical boundary scenario was chosen because it represented the "in between" level of vertical restraint on algorithm cell assignment.

Porosity model methodology

The porosity model was built in a similar manner to the facies model. The same horizontal (boundary polygon) and vertical (zones) 3D grid boundaries were tested. The grid cell dimensions x=20 ft, y=5 ft, and z=1 ft (on average) were used in the porosity

model as these were deemed the most appropriate for the facies model. Using the density porosity logs from the 13 wells the upscale well logs process (Figure 12) was used to

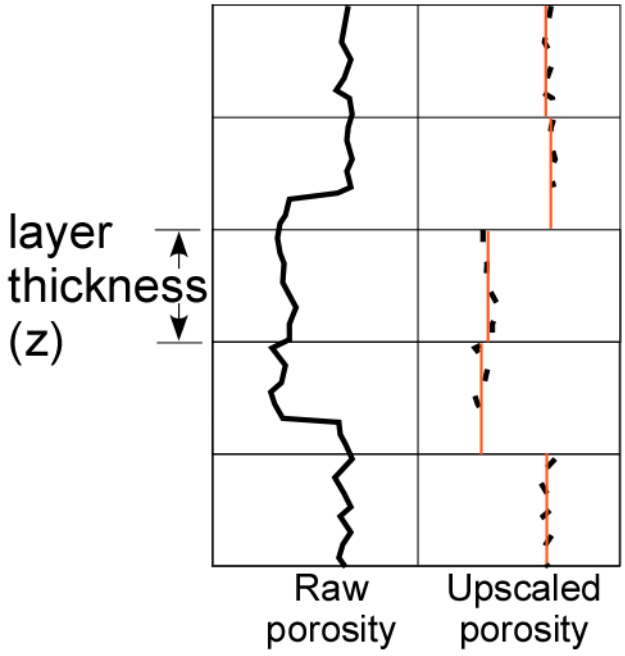

Figure 12: Example of the porosity log upscaling process

create upscaled porosity logs. Values for each z interval (layer thickness) of the upscaled porosity log equaled average porosity values for the same z interval on the original porosity log.

The petrophysical modeling process was used in conjunction with the upscaled porosity logs to assign values to the 3D grid cells. Three algorithms were tested in the models:

- Gaussian random function simulation
- kriging

- moving average

The kriging and moving average algorithms produced nearly identical versions of the model run using the Gaussian algorithm. The Gaussian algorithm (the default Petrel algorithm) was used in all subsequent porosity modeling. As with in the facies modeling the horizontal and vertical correlation ranges were set to values that would enable correlation across the 13 well study area (set to 6000 ft) and produce vertical porosity intervals large enough to discern meaningful features (4 ft).

III. RESULTS

Facies model results

Surfaces

Figure 13 displays the surfaces created from the xy polygon and the well tops. These surfaces were used to construct vertical boundaries in the facies model.

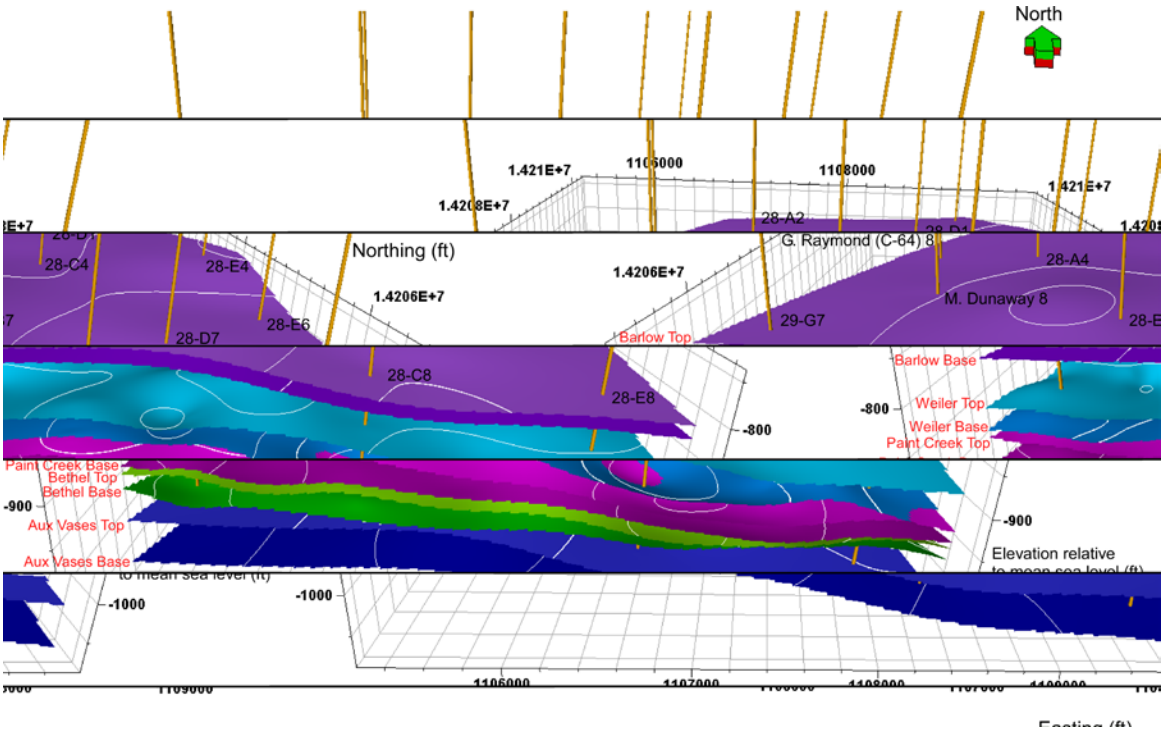

Figure 13: Surfaces created from xy polygon (study area) and well tops for the Barlow and the four main sands, these surfaces were used as vertical boundaries in the facies and porosity modeling

Facies log

Figure 14 displays the results of the facies log construction. A facies log was built for each of the 13 wells used in the facies model using the gamma ray logs, density porosity logs, the Petrel log calculator, and formulas representing the following if/then statements:

- If the porosity was greater than 0.1 and the gamma ray log value was lower than 60 API (American Petroleum Institute) units, then the interval was designated as sandstone.
- If the porosity was lower than 0.1 and the gamma ray log value was less than 60 API units, then the interval was designated as carbonate.
- If the gamma ray log value was greater than 60 API units, then the interval was assigned a shale facies designation.

The facies logs were used to assign values to the grid cells in the facies model.

Grid cell size

Examples of the various grid cell sizes and combinations of horizontal and vertical spacing are displayed in Figure 15. A grid cell size with xyz dimensions of 5x5x1 ft (z = average layer thickness) showed greatest detail (smoother layers and increased amount of small features) but caused computer operations to take longer, the level of detail was determined to be unneeded (smoothness of features given by 5x5x1 ft spacing only slightly more ascetically favorable than 20x20x1 ft spacing), and small features

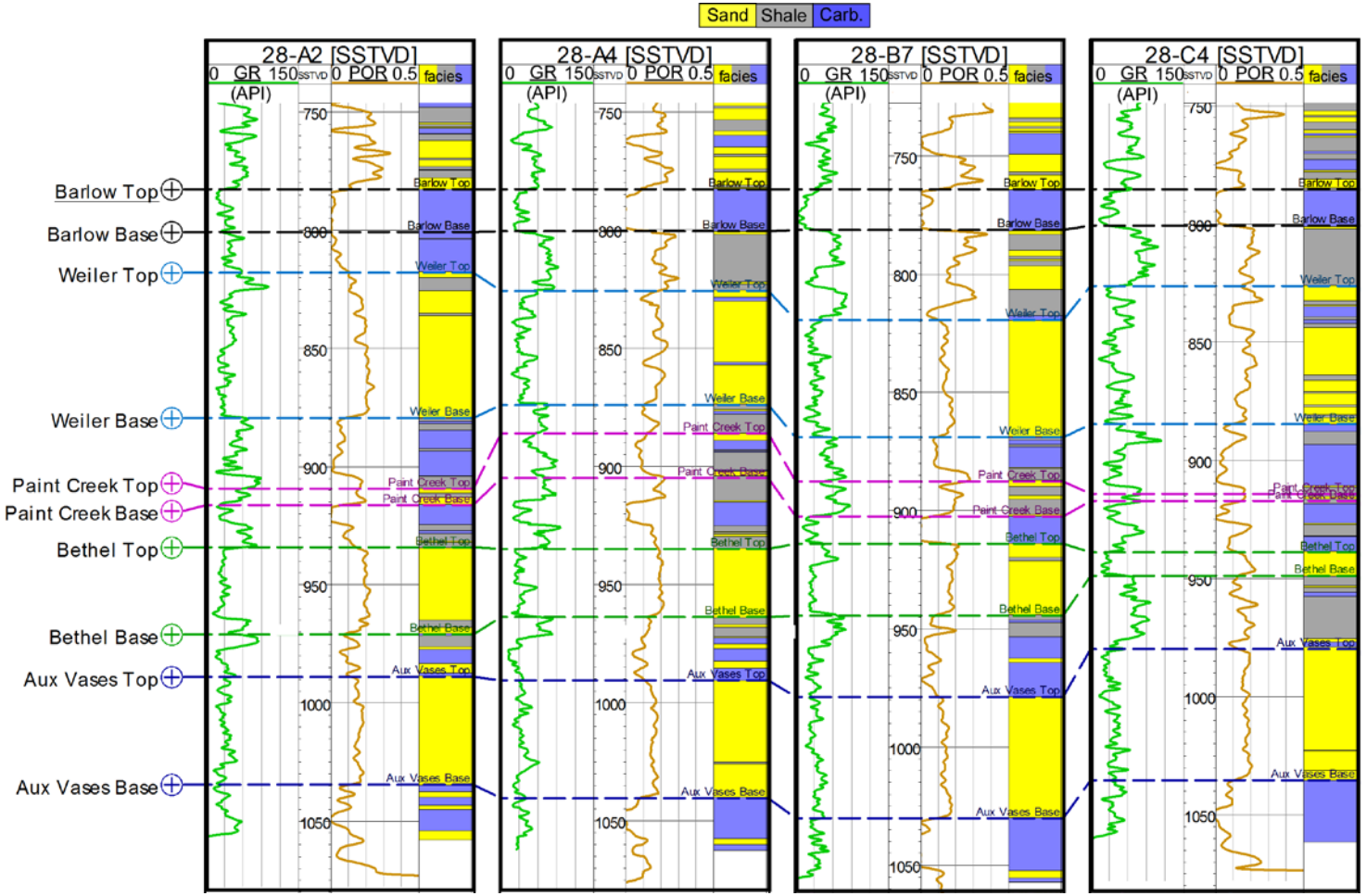

Figure 14: Facies logs constructed for the 13 study area wells, if porosity greater than 0.1 and gamma ray log value less than 60 API then the interval was deemed sandstone, if porosity less than 0.1 and gamma ray log value less than 60 API then the interval was deemed carbonate, if gamma ray log value greater than 60 API then the interval was deemed shale

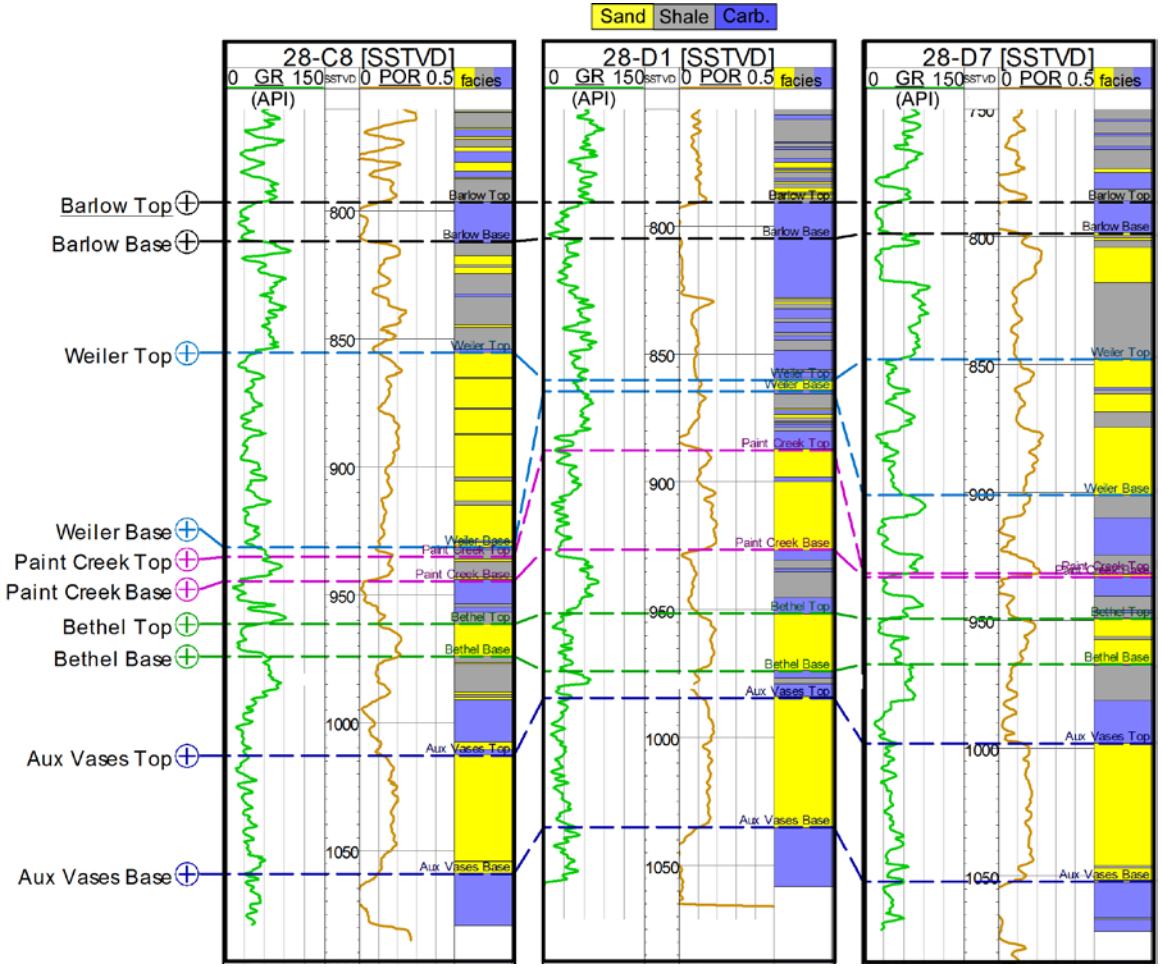

Figure 14 (cont'd): Facies logs constructed for the 13 study area wells

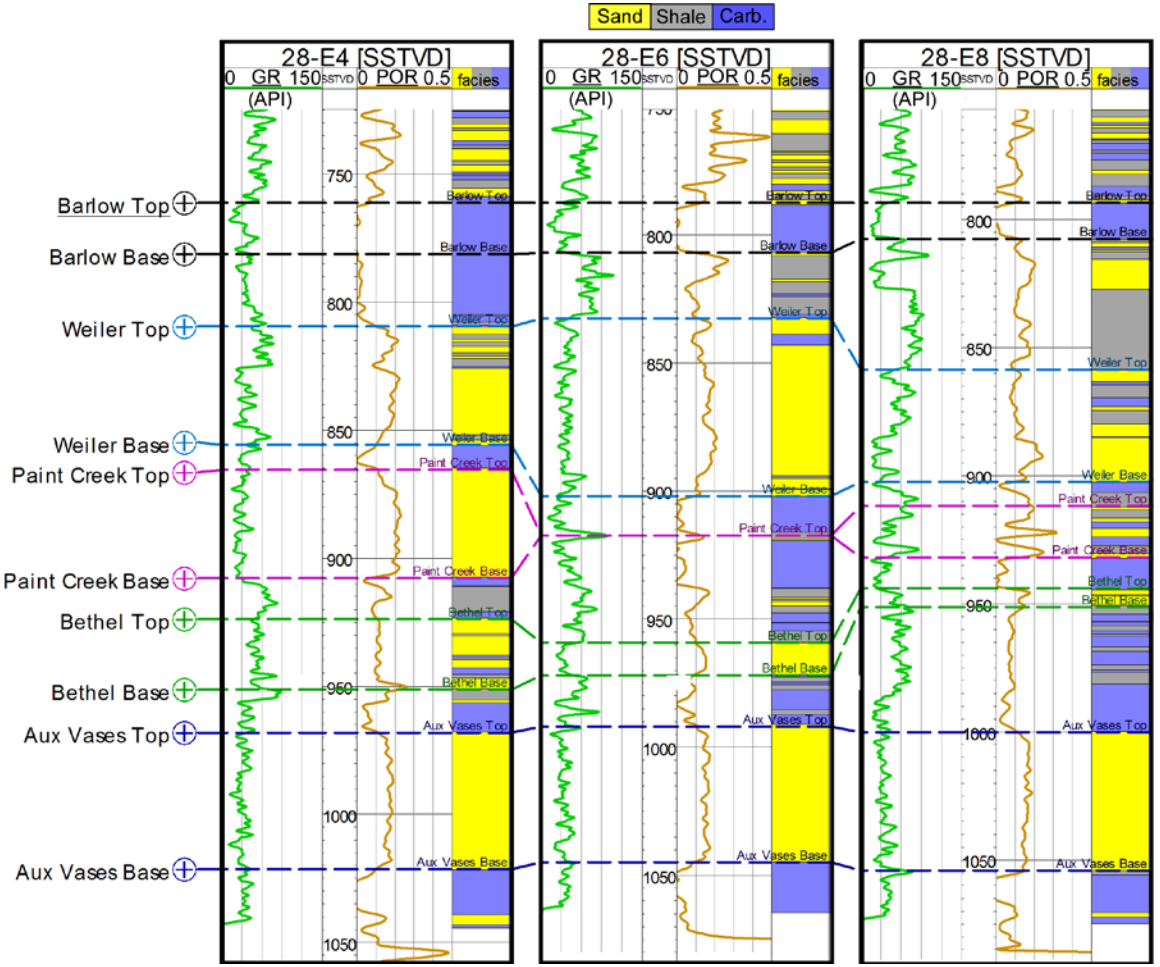

Figure 14 (cont'd): Facies logs constructed for the 13 study area wells

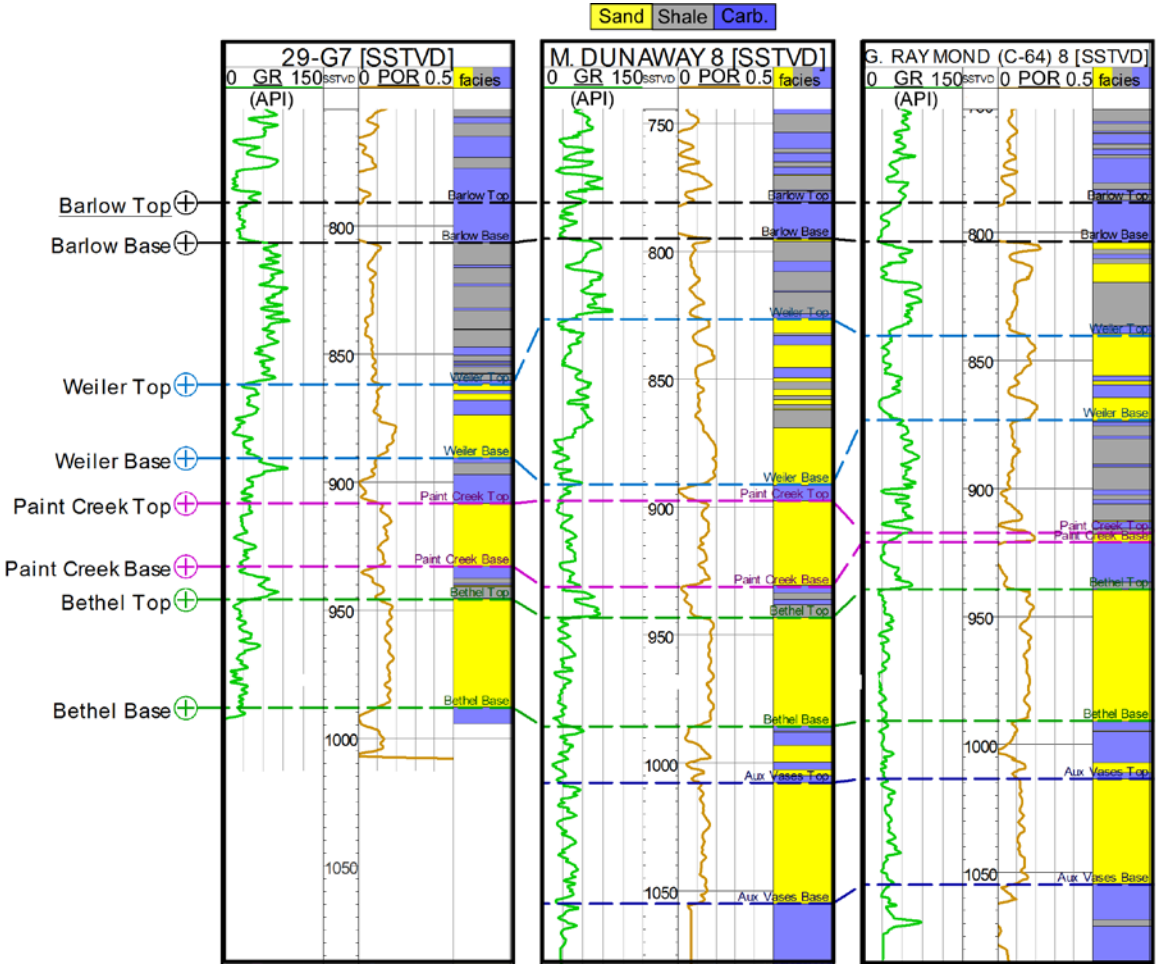

Figure 14 (cont'd): Facies logs constructed for the 13 study area wells

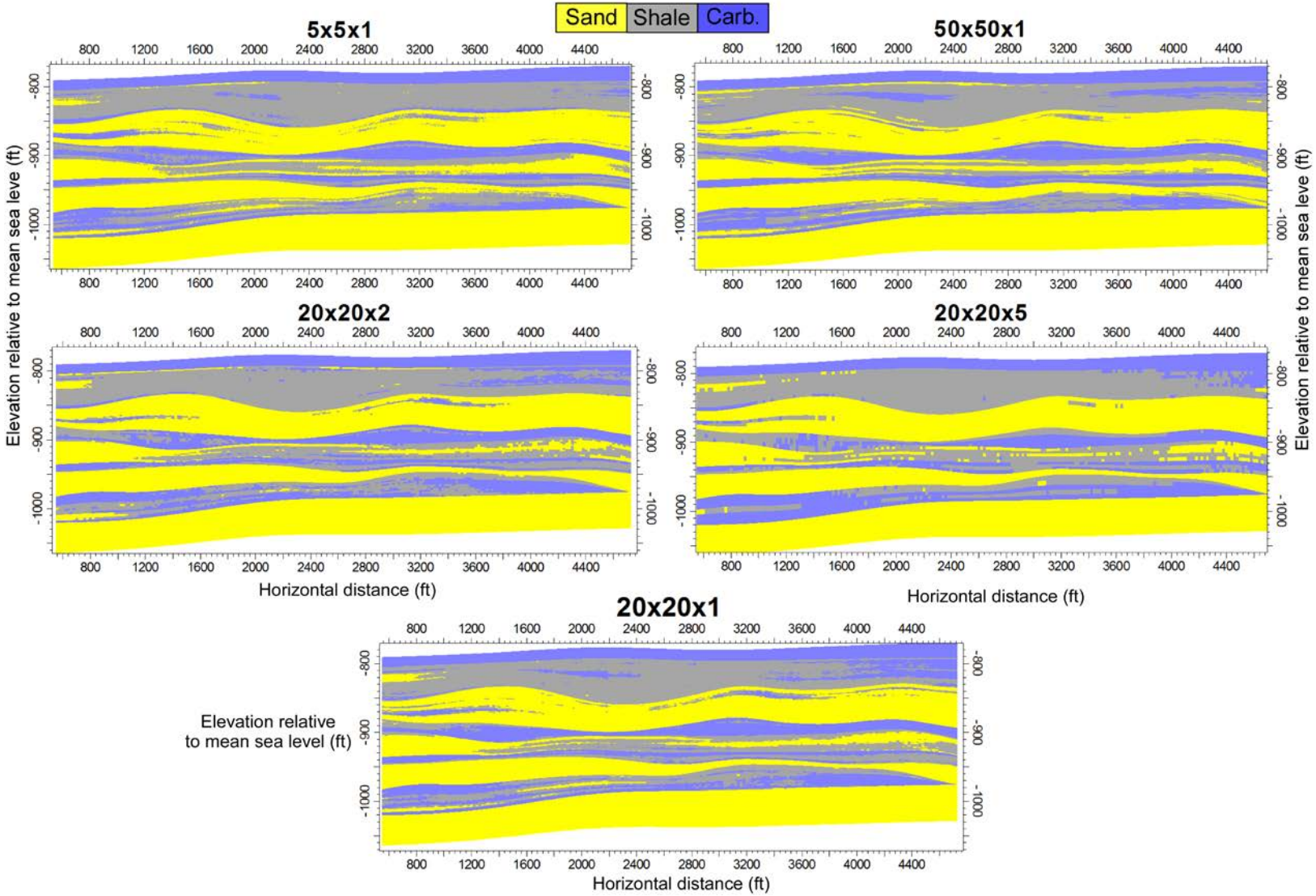

Figure 15: Evaluated grid cell sizes (cell dimensions in feet), used in facies and porosity modeling (facies model shown)

were most likely unjustified given the distance between well logs. A grid cell size of 50x50x1 ft was examined. Strata were markedly blockier, displaying less of the smooth nature displayed in the 5x5x1 model. An in between grid cell size of 20x20x1 was tested. The resulting model displayed smoother features than the 50x50x1, and the speed of computer operations increased significantly compared to the 5x5x1 model. A check of the facies modeling histogram used in each grid cell scenario showed that the same percentage of shale, sandstone, and carbonate facies cells were used in each of the models. In general, the three models run using the 1 ft z value displayed the same features with no significant loss of facies zones as the xy grid cell size increased. Increase in the vertical grid cell component produced a greater loss of features with increase in size. Because of the loss in detail shown in the 2 ft and 5 ft vertical grid cell dimension models and, as mentioned above, the logging mechanism is accurate to approximately 1 ft, the 1 ft vertical grid cell dimension was used in the making of the finished facies and porosity models.

Vertical boundaries

Figures 17, 18, and 19 display the three vertical boundary scenarios (lines of cross section used are displayed in Figure 16). The models in Figures 16, 17, 18 and 19 incorporated the Truncated Gaussian Simulation algorithm. The non-partitioned model placed no restriction on facies distribution. Facies were allowed to laterally and vertically change to shale and carbonate. The sandstone surface partitioned model (geologic model) placed the most restriction on facies distribution. Sandstone facies within the four

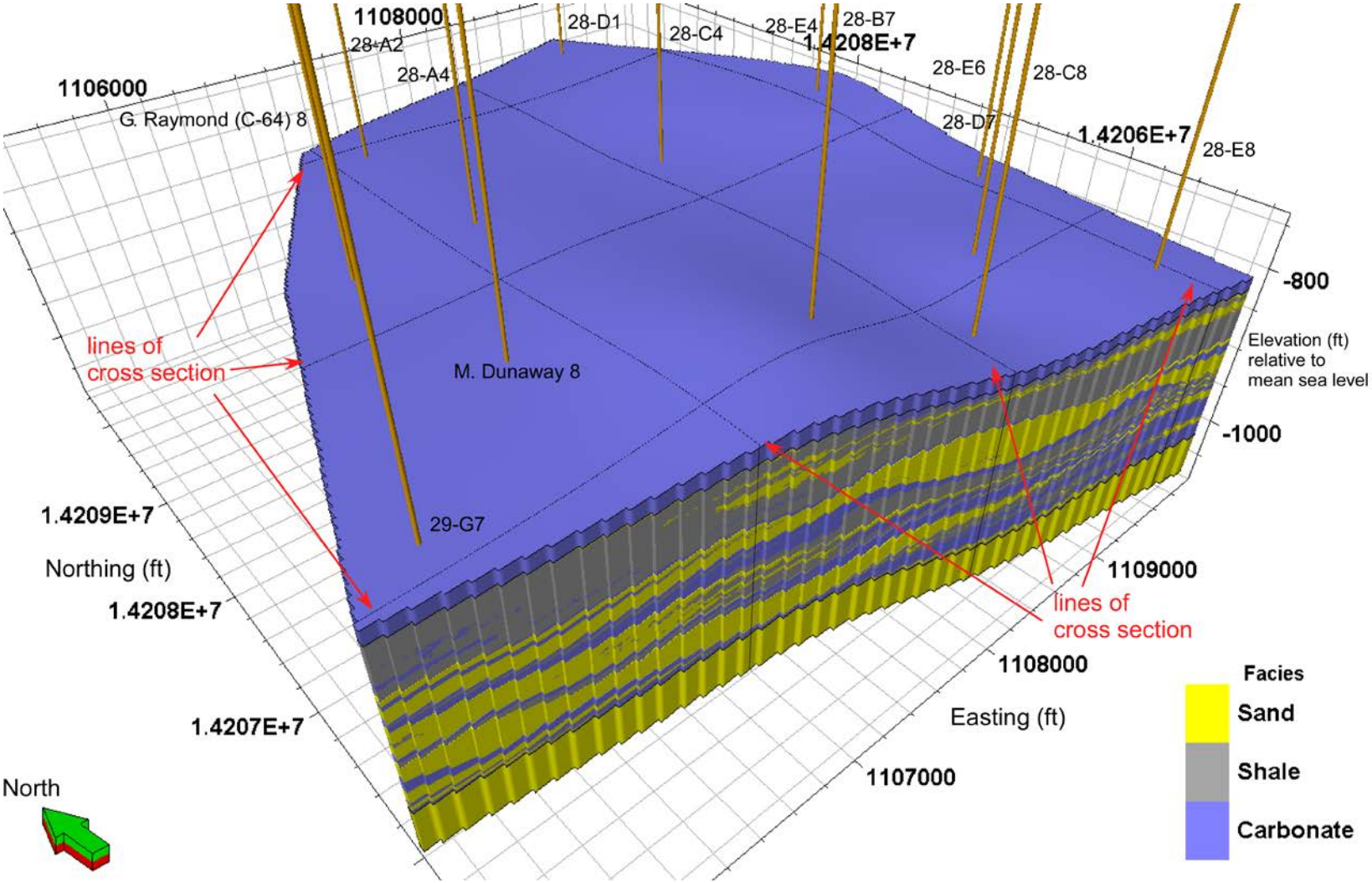

Figure 16: Sandstone surface partitioned facies model displaying lines of cross section used in Figures 17, 18, and 19

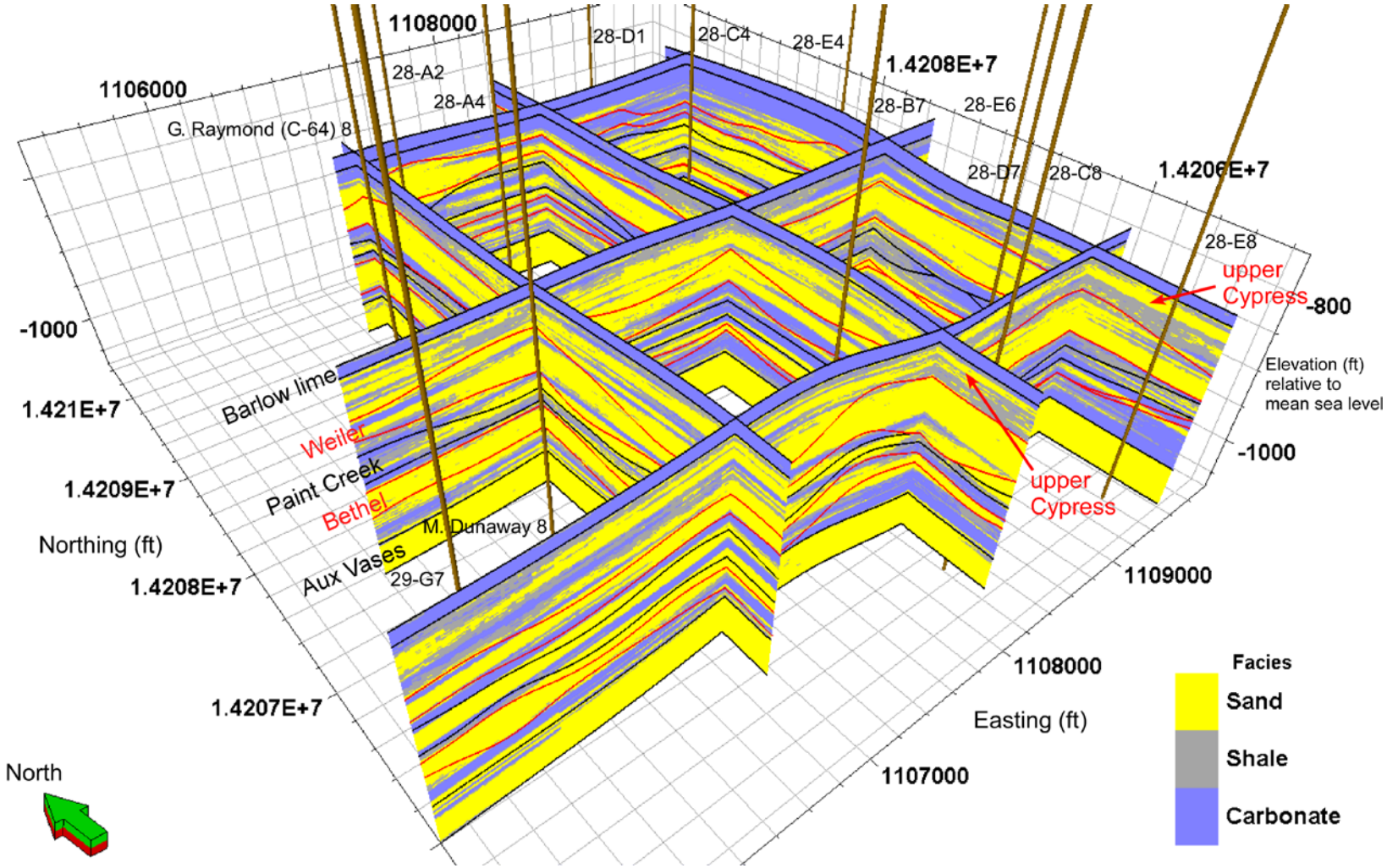

Figure 17: Non-partitioned vertical boundary facies model, no surfaces between the surfaces of the top of the Barlow and the Aux Vases base controlling facies assignments of cells

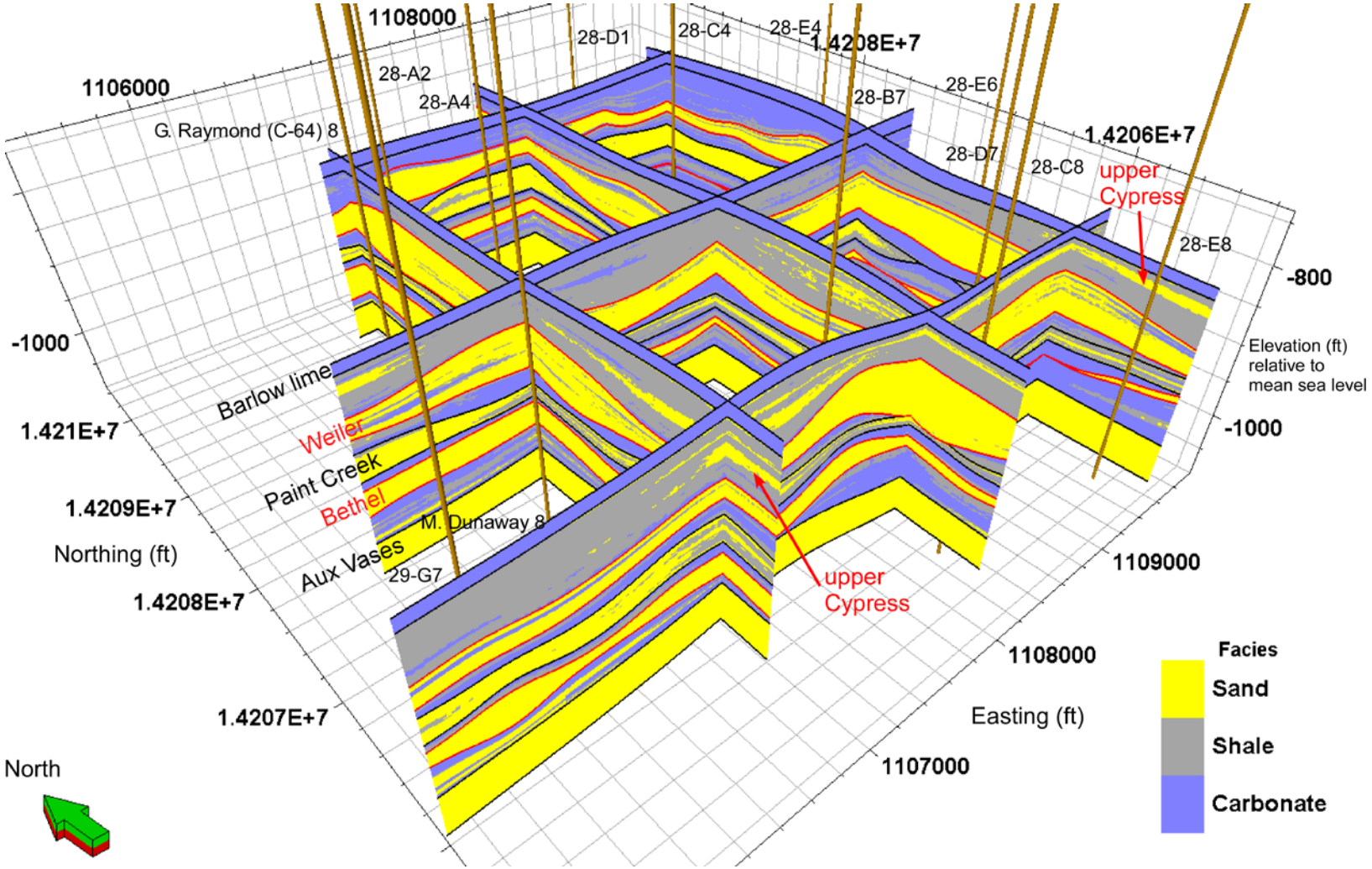

Figure 18: Sandstone surface partitioned facies model, the surfaces of the Barlow and the four main sands partition the model and control facies assignments of cells

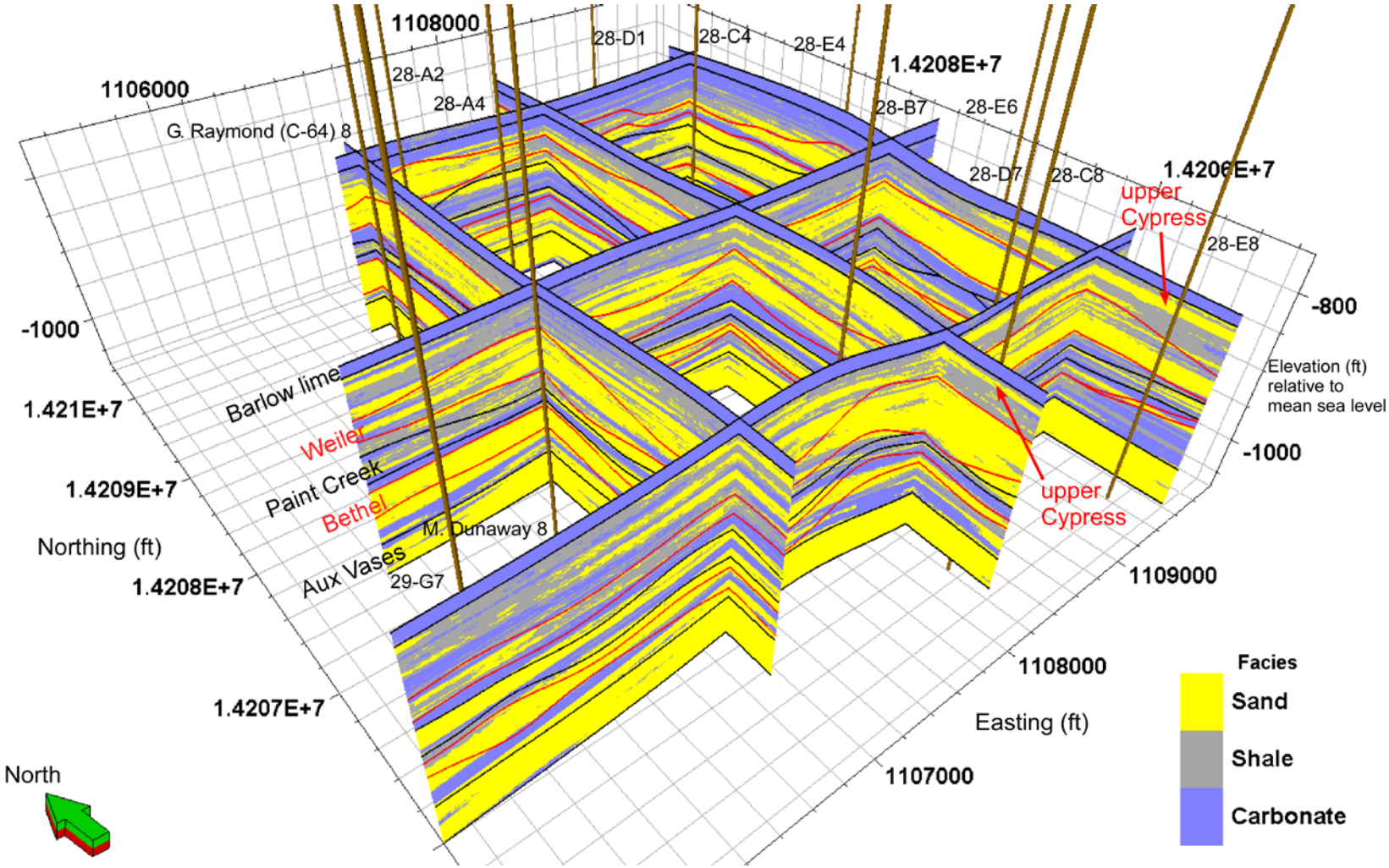

Figure 19: Zone-partitioned facies model, surfaces midway between the four main sands partition the model and control facies assignments of cells

sandstone zones showed little to no change into shale and carbonate. Sandstone designated cells exist outside of the four main zones but are scarce. An Upper Cypress sandstone known to exist at Loudon is present in areas in the region between the base of the Barlow and the top of the Weiler. The level of restriction on facies distribution within the zone-partitioned model is in between the two model extremes. The zone-partitioned model displayed the geometry of the rock bodies better than the non-partitioned model. The sandstone surface partitioned model displayed the truest rock body geometry and when compared with the other two models displayed the difference between the sandstone zone elevations as predicted by the algorithm and the elevations picked from the well logs.

Algorithm/variogram

The Truncated Gaussian Simulation (TGS) and the Sequential Indicator Simulation (SIS) produced similar models. The Petrel help manual suggested using the TGS algorithm for fluvial depositional sequences such as those found at Loudon. The Sequential Indicator Simulation (SIS) provided a detailed model that consisted of a multitude of small (~1 ft thick) stratigraphical features varying in horizontal (xy) dimensions. The detail of the SIS model was unnecessary for the project, and the models took ~10x the time to run compared to those run using the TGS algorithm. The TGS algorithm was used in subsequent facies modeling. Various combinations of horizontal and vertical correlation ranges were evaluated in the determination of an appropriate variogram scenario to be used to guide the algorithm. In general, adjustments to the

horizontal correlation range caused the stratigraphical features to increase or decrease in length. The rock units are capable of spanning the width of the modeled area (~5500 ft), so correlation from one side of the model to the other was desired as a possibility. The horizontal correlation range was set to 6000 ft to ensure full correlation across the model. In general, adjustment to the vertical correlation range caused stratigraphical features to increase or decrease in thickness. A high range caused smaller (~1-5 ft) features to be lumped together into one large feature. Low ranges created a multitude of small (~1 ft) features. Small features were desired in the model to a certain extent, but the smallest (~1 ft) features were not necessary. The minimum limit on sandstone thickness that will be opened (perforate well casing) to production or injection set by the Loudon field operator is 4 ft, so the vertical correlation range was set to 4 ft.

Quality control check of picked surface elevations

The facies model was checked for the quality of picks made from well log data in producing the various stratigraphical horizons used in bounding the model. Using the Petrel intersection plane function the model was visually checked by scrolling through in a step rate (100 ft per step) manner from one end of the model to the opposite end. Two areas stood out as possibly containing sandstone surface elevation errors. In the vicinity of the 28-E4 well sandstone cells were present directly above the top of the Weiler sandstone zone. A check of the 28-E4 logs (porosity, gamma ray, facies) showed that the interval of sand at the top of the Weiler was not included in the Weiler interval picked on the well log (Figure 20). The correction was made, and the sandstone surface partitioned

model rerun using the new corrected sandstone surface (Figure 21). Another area was noticed during the visual inspection of the model. In the vicinity of the 28-C8 well the

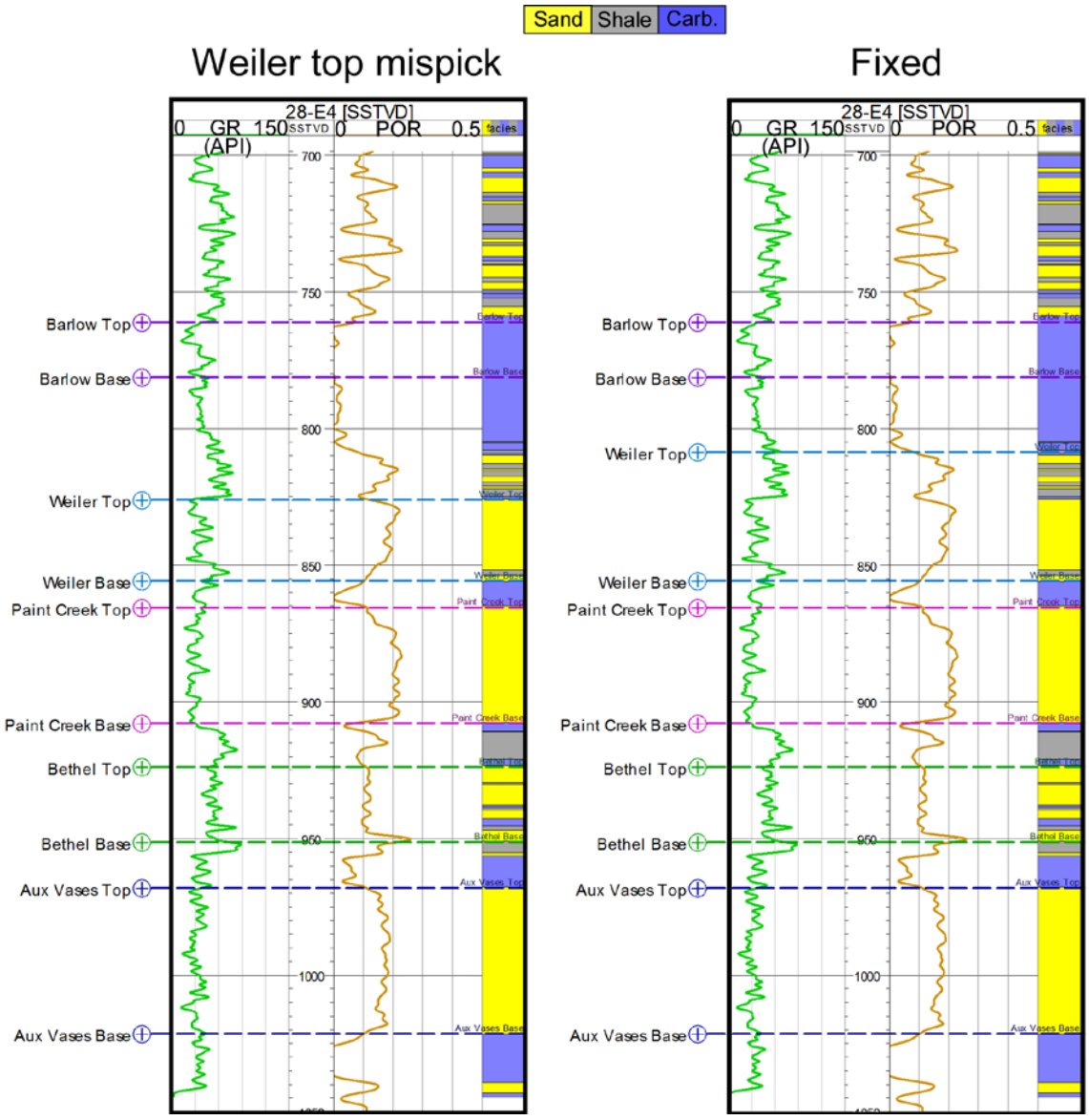

Figure 20: Mispicked well top at well 28-E4 and subsequent fix

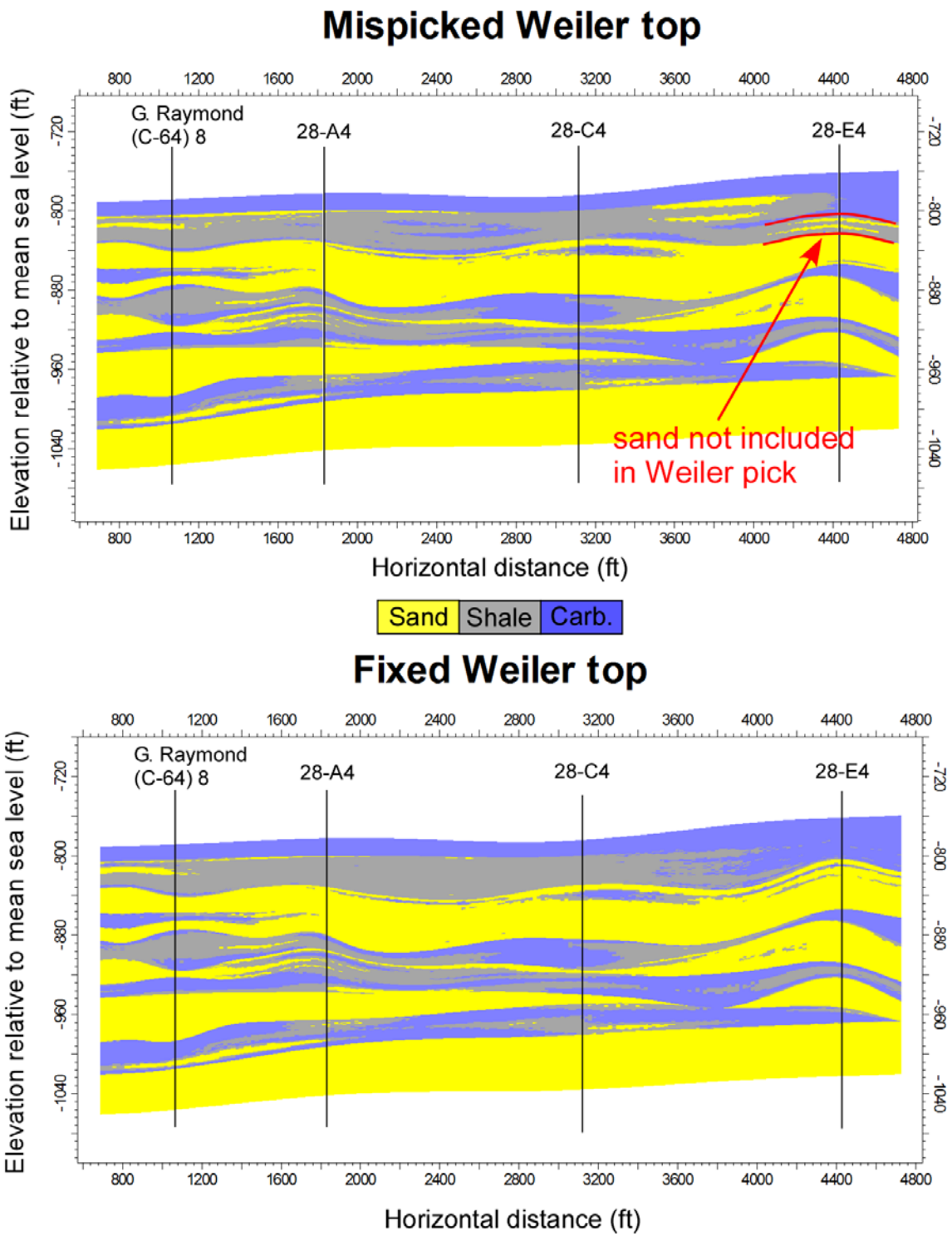

Figure 21: Mispicked well top at well 28-E4 and subsequent model fix

base of the Weiler noticeably drops in elevation to the elevation where the Paint Creek zone is located. Compared to the same zone within a thousand feet of the well, the thickness of the Weiler in the area around the 28-C8 is profoundly greater. A check of the log showed that the sand at the bottom of the Weiler, while only separated by ~2 ft of shale from the rest of the Weiler sand could possibly have belonged in the Paint Creek interval as an upper feature. Analysis of the Paint Creek interval in the area of the model in question shows that the zone is practically non-existent. The sand most likely belongs in the Weiler interval.

Porosity model results

The three vertical boundary scenarios were examined with a grid cell size of 20x20x1 used in each model. The three porosity models are displayed in Figures 23, 24, and 25. Lines of cross section are displayed in Figure 22. Similar to the facies model, decreased amounts of interior partitions resulted in increased amounts of high porosity (high enough to qualify as a sandstone facies) cells existing outside of the sandstone zones established by the well log data. The established sandstone zones (Weiler, Paint Creek, Bethel, Aux Vases) in the sandstone surface partitioned model contain the vast majority of high porosity cells, though areas of high porosity exist outside of the zones. High porosity cells are located north and southwest of 28-B7 in the zone between the top of the Weiler and the base of the Barlow. Comparison to the results of the facies model indicates that these high porosity cells were designated shale in the facies model. As will be discussed below, the porosity model may not be a good indicator of sandstone facies.

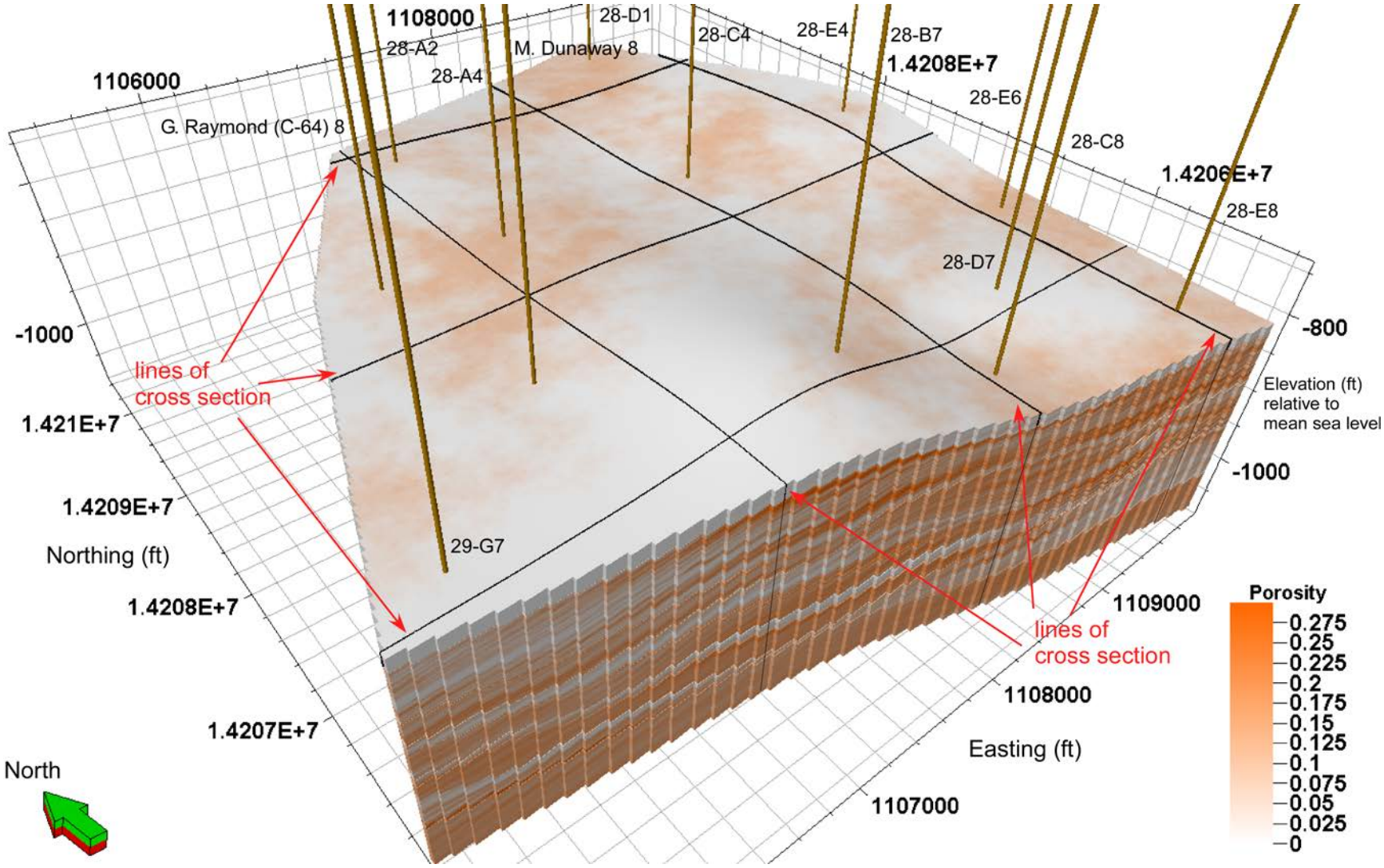

Figure 22: Porosity model (sandstone surface partitioned) displaying lines of cross section used in Figures 23, 24, and 25

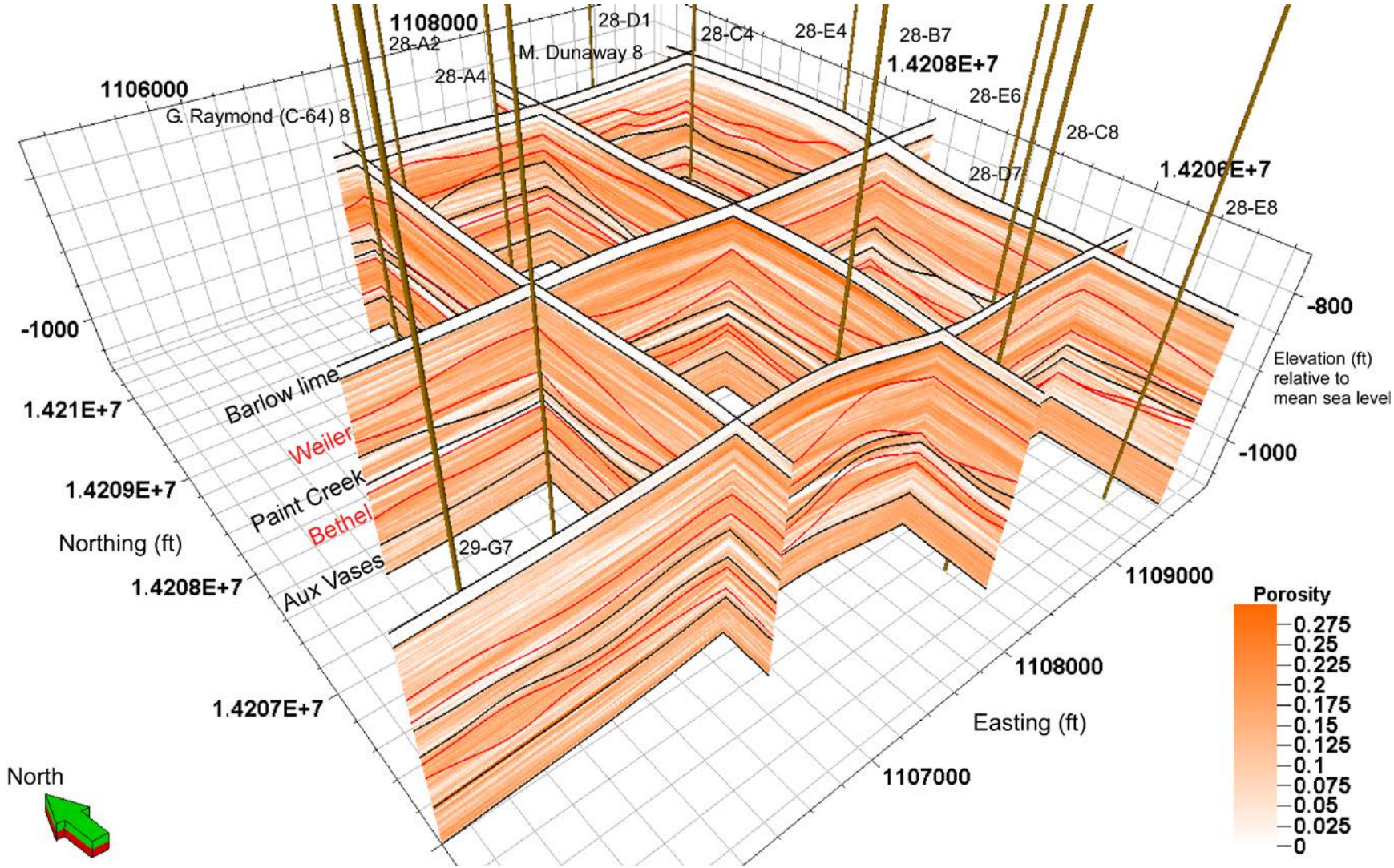

Figure 23: Non-partitioned porosity model, no surfaces between the surfaces of the top of the Barlow and the Aux Vases base controlling porosity assignments of cells

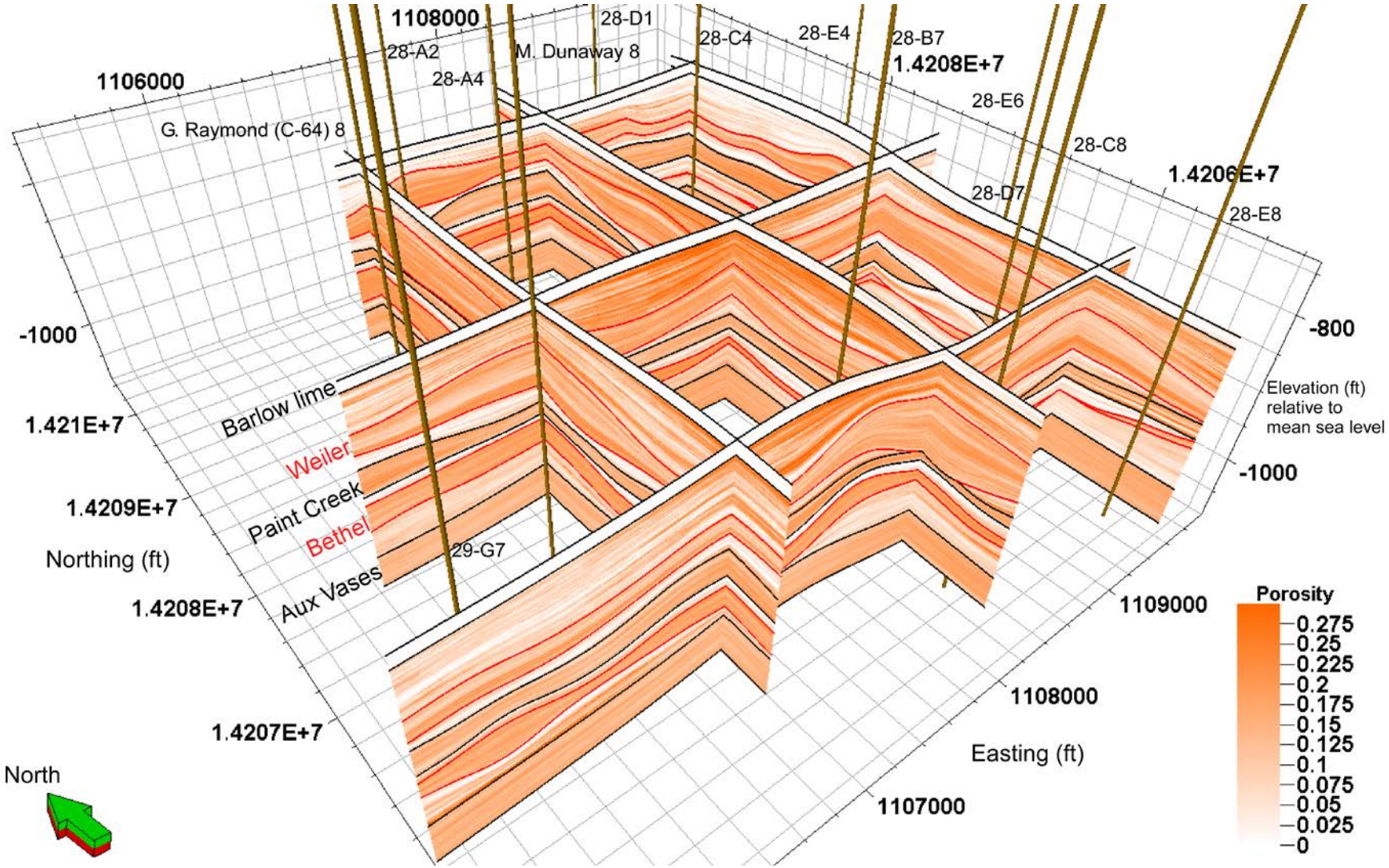

Figure 24: Sandstone surface partitioned porosity model, the surfaces of the Barlow and the four main sands partition the model and control porosity assignments of cells

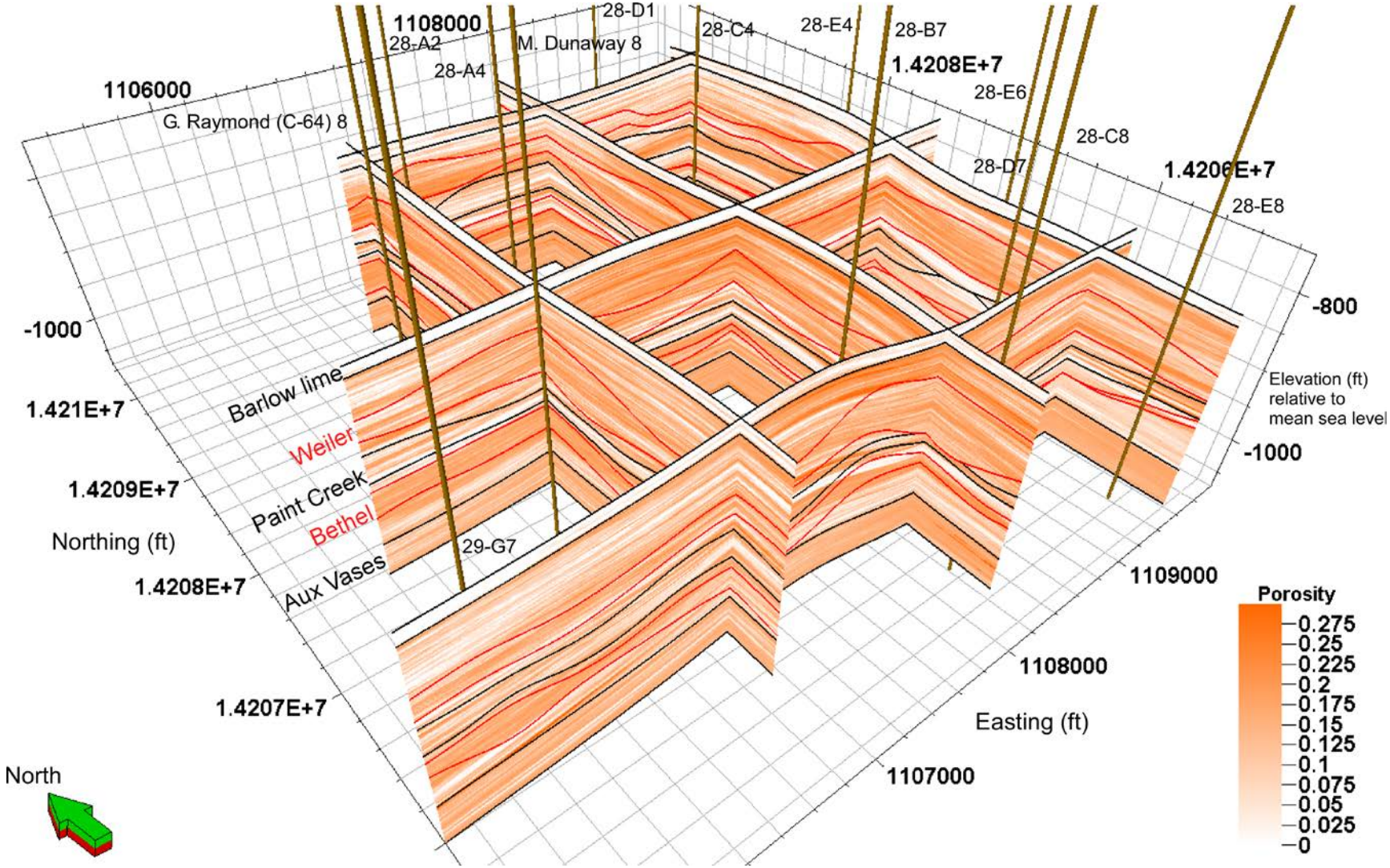

Figure 25: Zone-partitioned porosity model, surfaces midway between the four main sands partition the model and control porosity assignments of cells

IV. DISCUSSION

Facies model discussion

Vertical boundary variations

Non-partitioned model

Advantages and disadvantages exist with each of the three vertical boundary scenarios. The non-partitioned model allowed the Petrel operations (algorithm, variogram, etc.) to assign facies values with the most freedom. No interior restraints are present to force facies assignments, so the full range of interpretation by Petrel is displayed. A disadvantage to this model is that sandstone facies designated cells exist outside of the sandstone zones as established by the geologic model (sandstone surface partitioned model). Sandstone facies cells that exist outside of the known sandstone intervals at the location of a well are erroneous to a certain extent because the sandstone zone elevations used in the geologic model were determined at the location of the well. However, the sandstone facies cells that are present a given distance away from a well should be examined because sandstone zone elevations in the geologic model a given distance away from a well are not known but interpretations made by Petrel.

Geologic model

The geologic model boundary scenario displays the truest representation of rock unit elevation given the available data. However, the elevations of the sandstones to a certain degree are not that important. At the Loudon Oilfield if a sandstone displaying good porosity (high enough to contain economically beneficial oil reserves) is present in a given location and an approximate elevation is established, then a well will be drilled in that location regardless of forehand knowledge of exact elevation. The variance in elevation between the geologic model and the other two models is small and would not hinder drilling efforts. Most important is the location of the porous sandstones laterally.

The geologic model boundary scenario forces sandstone cell values to remain within the boundaries of the given sandstone elevation interval. This does not allow for certain areas of the zone to grade into another facies as would be expected in this depositional environment. Separate upper and lower units within both the Weiler and Paint Creek zones are known to exist at Loudon. The facies populated geologic model shows some lenses of non-sandstone facies, which could represent the division between upper and lower units. However, the upper and lower sandstone units above and below (respectively) the lens ultimately tie back into one another, forming one sandstone. The upper and lower units should not tie into one another because they are separate sands.

As mentioned above, an upper Cypress sandstone is present in areas of the model. This is a less produced sandstone unit at Loudon but has been opened to production and water injection in areas of the field. Other sandstones that are present outside of the four established sandstone zones in the model should be investigated.

Zone-partitioned model

Facies patterns in the zone-partitioned model fall somewhere in between the two extremes produced by the other two models. Sandstone is present outside of the areas designated sandstone by the sandstone surface partitioned model but not to the degree that is shown in the non-partitioned facies model. The interior partitions established at the midway points between the known sandstone intervals prevent the algorithm from using facies values on the opposite side of the partition that bounds the zone being assigned values. Geometries of the units in the zone-partitioned model closer resemble those found in the sandstone surface partitioned model than the geometries provided by the non-partitioned model. The Barlow top surface and the Aux Vases base surface serve as the top and base of the model and are based on structural data obtained from logs. The interior partitions are set at midway points between sandstone surfaces that were based on logs and serve as indicators of true structural geometry, but in locations on logs where sandstones pinch out an estimate of the midway point was made. In areas of the model where pinch outs occur, the geometry of the beds is less certain due to the approximated midway points. Though, as mentioned above, knowledge of the exact depth of the beds is not necessary.

Validation of the facies model

A cross section of the model that omitted well 28-D1 is displayed in Figure 26 with the original model with all 13 facies logs incorporated. The lower two sandstones (Bethel and Aux Vases) appear virtually the same compared to the original model. The

Paint Creek zone has more sandstone designated cells, and the Weiler has less sandstone cells relative to the original model. In the log-omitted model increased amounts of sandstone cells are present in the area above the Weiler (upper Cypress). A cross section of the model that omitted well 28-D7 is displayed in Figure 26 with the original model. With consideration to the overall sandstone geometry, the two models appear in the figure closer in comparison than the two models that analyzed the 28-D1 omission, but, as in the 28-D1 analysis, differences in facies designations exist. Analysis of the logs displays the true contrast between the well-omitted facies models and the well-included facies logs (Figure 27). A count of the feet of sand in each of the four logs (28-D1 facies log, 28-D1-omitted facies log, 28-D7 facies log, and the 28-D7-omitted facies log) shows that the 28-D1 facies log and the 28-D1-omitted facies logs had roughly the same amount of sand with 114 ft and 113 ft, respectively. The 28-D7 facies log and the 28-D7-omitted facies logs had 126 ft and 150 ft, respectively. The differences in sand amounts between the logs may be due to the surrounding well data. Since there was no log at the 28-D1 and 28-D7 locations the algorithm assigned facies values at those two locations based on the facies log values from the nearest neighboring wells. A check of the facies logs (Figure 14) showed that the nearest neighbors of well 28-D1 (28-A2, 28-C4, and 28-E4) have an average total sand amount within the Barlow to Aux Vases interval of 120 ft. This is close to the total sand amount of 113 ft that was calculated in the 28-D1 log omitted facies model. The neighboring wells of well 28-D7 (28-B7, 28-C8, 28-E6, and 28-E8) have an average total sand amount of 135 ft, and the closest neighboring well (28-C8) has a total of 160 ft of sand. This could explain the 150 ft of sand present in the 28-D7

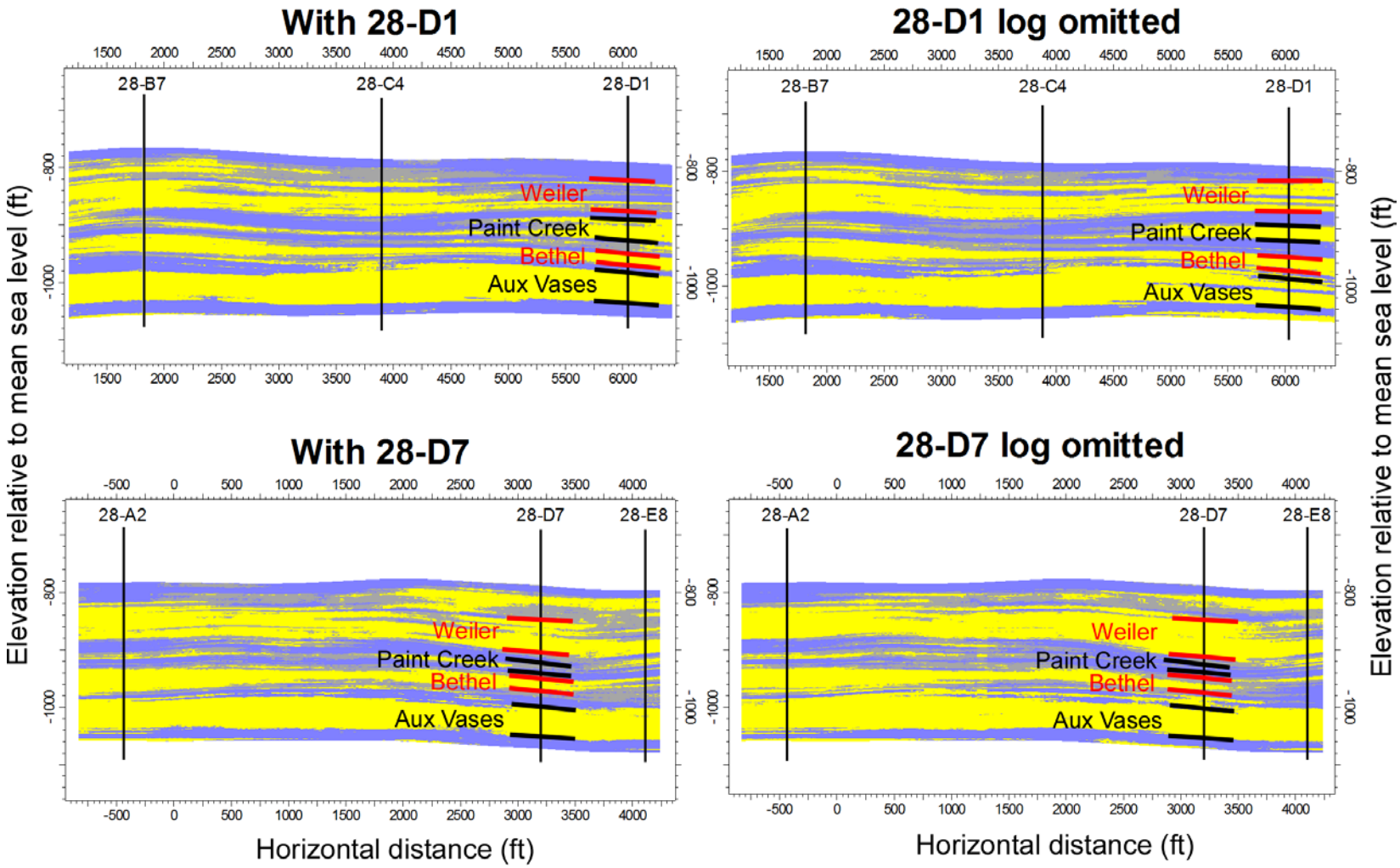

Figure 26: Cross sections showing effects on model with omission of wells 28-D1 and 28-D7

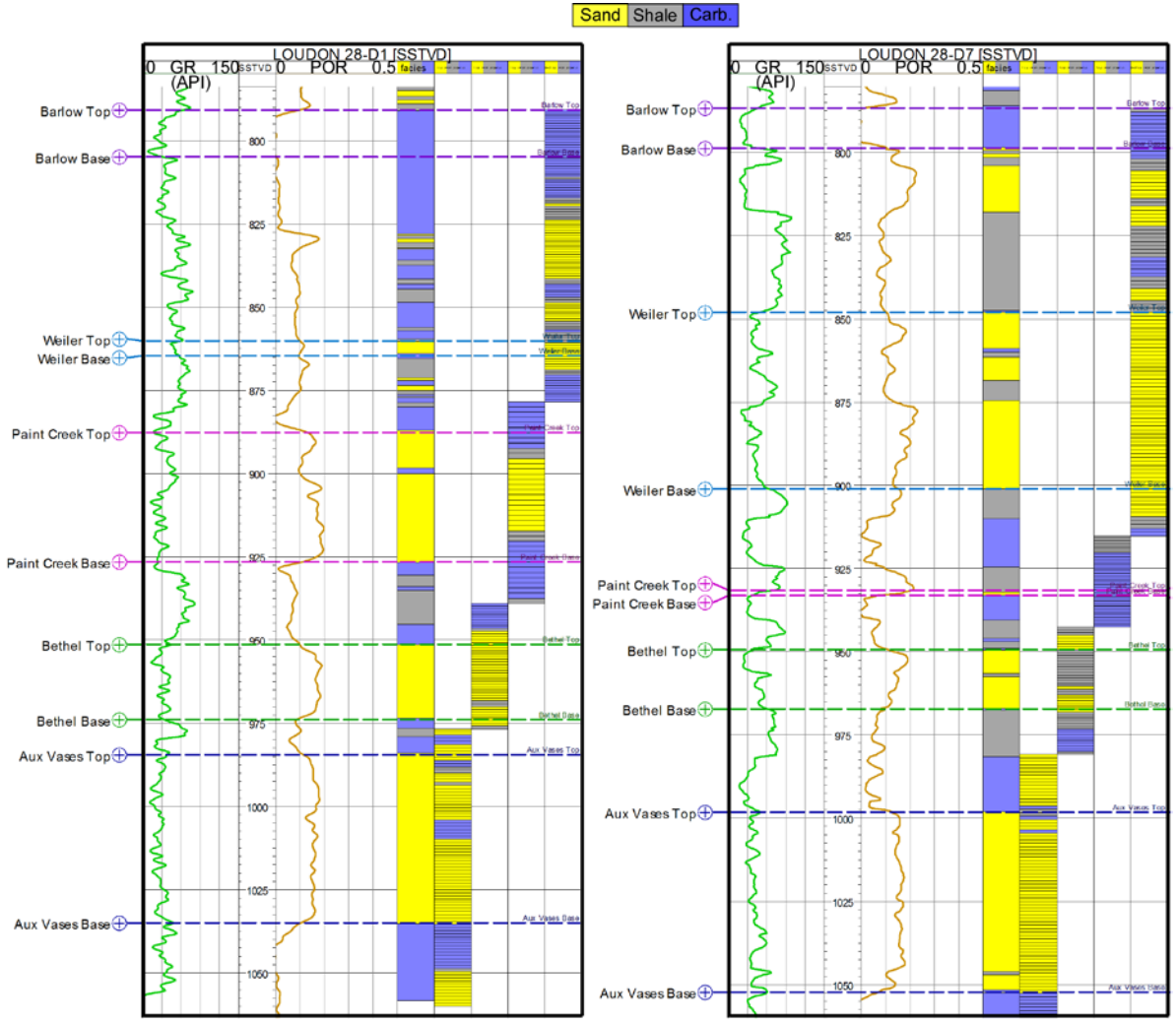

Figure 27: Comparison of facies logs (left) and facies model output with 28-D1 and 28-D7 facies logs omitted (four columns to right of facies log)

location of the 28-D7 log-omitted facies model. In this validation scenario, the two model extremes showed that greater proximity from the well log data did not equate to increased variance in cell assignments compared to a well in closer proximity to surrounding well data, but vice versa. Based on the total (disregarding vertical distribution) calculated feet of sand in the two facies logs and the two log-omitted facies logs, overall the validation exercise showed that the sandstone facies cell assignments of the facies model were accurate in a range of ~80% (28-D7) to ~100% (28-D1). Though, the degree of accuracy range may differ elsewhere in the facies model.

Facies model as a tool for locating future production and injection wells

The facies model was analyzed for potential production and injection wellspots by first finding appropriate ground surface locations and then by assessing the thickness of sands at each prospective location. Using a field map constructed using *ArcMap 10* showing existing well locations and lease boundaries, the study area was assessed for potential locations of new wells (production or injection). Legally, production wells have to be a minimum of 330 ft from a lease boundary or other production well that produces from the same depth interval. Though deep (Devonian) producing wells exist at Loudon, all wells in the study area produce from the same depth interval (Chesterian-Mississippian). Production wells should be a reasonable (minimum 300 ft) distance from existing injectors to maximize the radial sweep capability of the injection well and to avoid injecting into fractures that exist in rock bodies within a given distance from production wells (rock units produced by production wells are purposely hydrofracked by

the operator to maximize fluid withdrawal). Injection wells should be placed in locations that have surrounding production wells present (and vice versa, production well placements should have injection nearby). This allows for take points for the injected fluid and freed oil. There are no legal restrictions on injection well placement. Gas storage wells (Devonian) are omitted from the maps because for the most part the wells do not interfere with production or injection well placement (gas storage operator controls a typically less than 50 ft radius of land around well). Plugged wells are shown on the map and represent areas where previous injection or production efforts proved uneconomical or impossible most likely due to poor quality or nonexistent sand in the production interval.

Eight potential production well locations were found that obeyed the well location criteria (Figure 28). One potential injection well location was determined. With ground surface locations determined, thicknesses of each of the four sand zones at each potential well location were assessed. For a well to be drilled at Loudon a minimum 20 ft (set by operator) of overall (all four sandstones combined) sand thickness must be believed to exist at the prospective location. Only the top ~10 ft of the Aux Vases is considered in the calculation because the Aux Vases thickness interval exists in the vicinity of the original (before withdrawal of oil and waterflooding) oil-water contact. So, below a certain elevation (oil-water contact) oil was never present within the rock body, and only water exists. This is also the reason that when the Aux Vases is opened to production or injection in a well only the top ~10 ft are opened. Two methods were used to assess the sand thicknesses. The first method involved analysis of the facies model. The sandstone

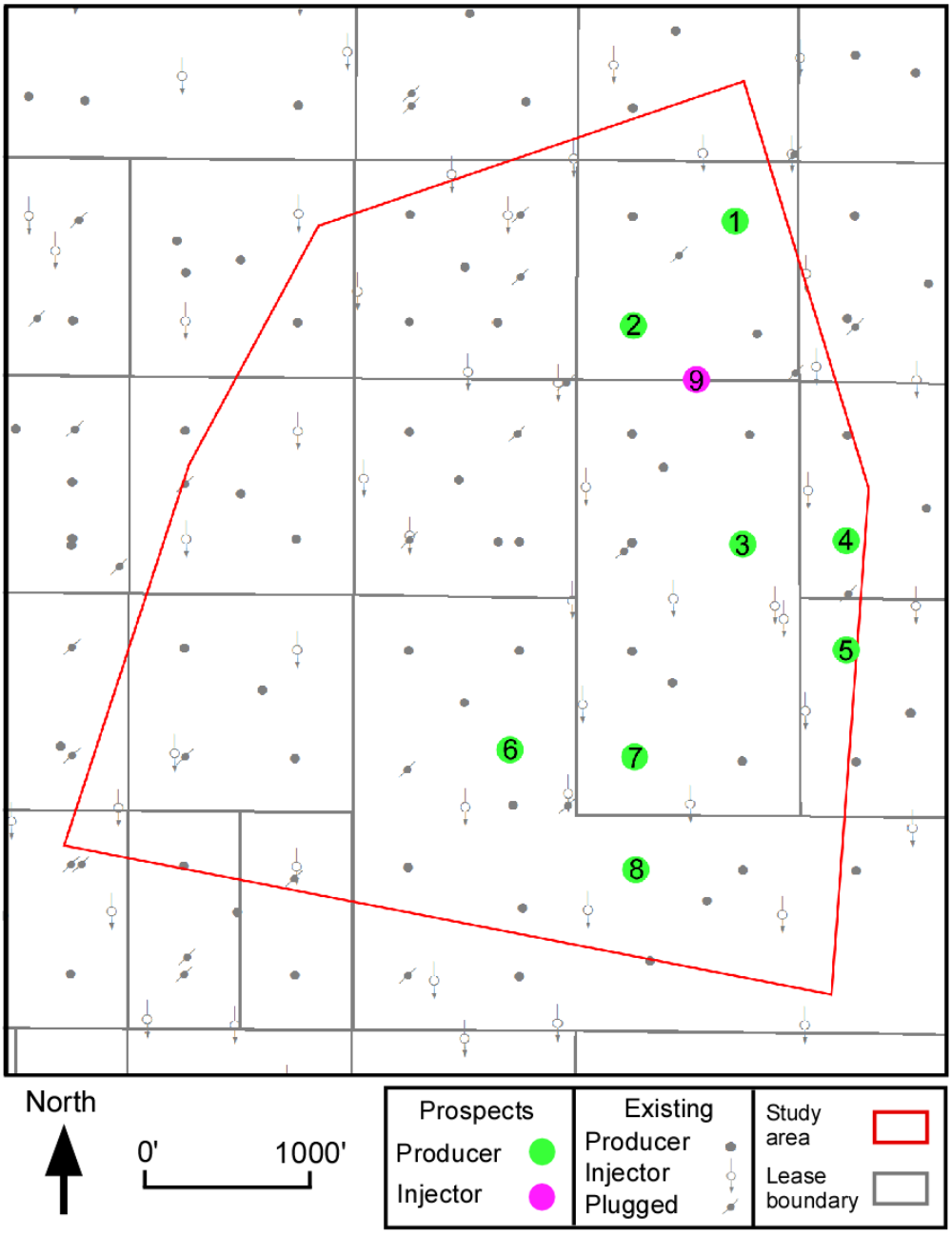

Figure 28: Loudon Field map overlain with study area polygon and prospective wellspots

surface partitioned (geologic model) facies model logs at the nine prospective well locations were assessed for net sand thicknesses inside and outside of the four main sandstone intervals (Figure 29). The sandstone surface partitioned model was chosen out

of the three vertical boundary scenarios because the sandstone surface partitioned model was assumed to be the most accurate portrayal of sand distribution due to the incorporation of the well data of all wells in and around the study area and the establishment of the four main sand intervals based on the well data. Results of this analysis showed the net thickness of the sands at each prospective well location based on facies predictions by Petrel operations. Table 1 displays the facies model net thickness data. Two areas of producible thickness (>4 ft) existed outside of the four main sandstone intervals. Prospect wells 6 and 8 had sand present between the base of the Barlow lime and the top of the Weiler. This is the upper Cypress sand referred to previously, which has been opened to production in various wells at Loudon. Due to the sand amounts of the nine wellspots each totaling over the 20 ft minimum, the location of the extra sand was to a certain degree a moot point. The wells would be drilled based on the thickness data of the four main zones alone. If extra sand of a minimum 4 ft thickness resided outside of the established intervals (four main sandstones), the beds would be seen during the logging process and assessed on whether or not to be opened to production (well casing would be perforated and the zone injected into or produced from). However, a goal of the production process is to drill a well in a location that has a relatively large amount of sand in the target range (greater volumetric sweep potential for injection and greater volumetric withdrawal potential for production), so the extra sand located outside of the known intervals creates a more appealing prospect. The second method of sand thickness analysis at the nine prospective sights involved construction of net sand thickness isopach maps using net sand data of all wells in and around the study area and

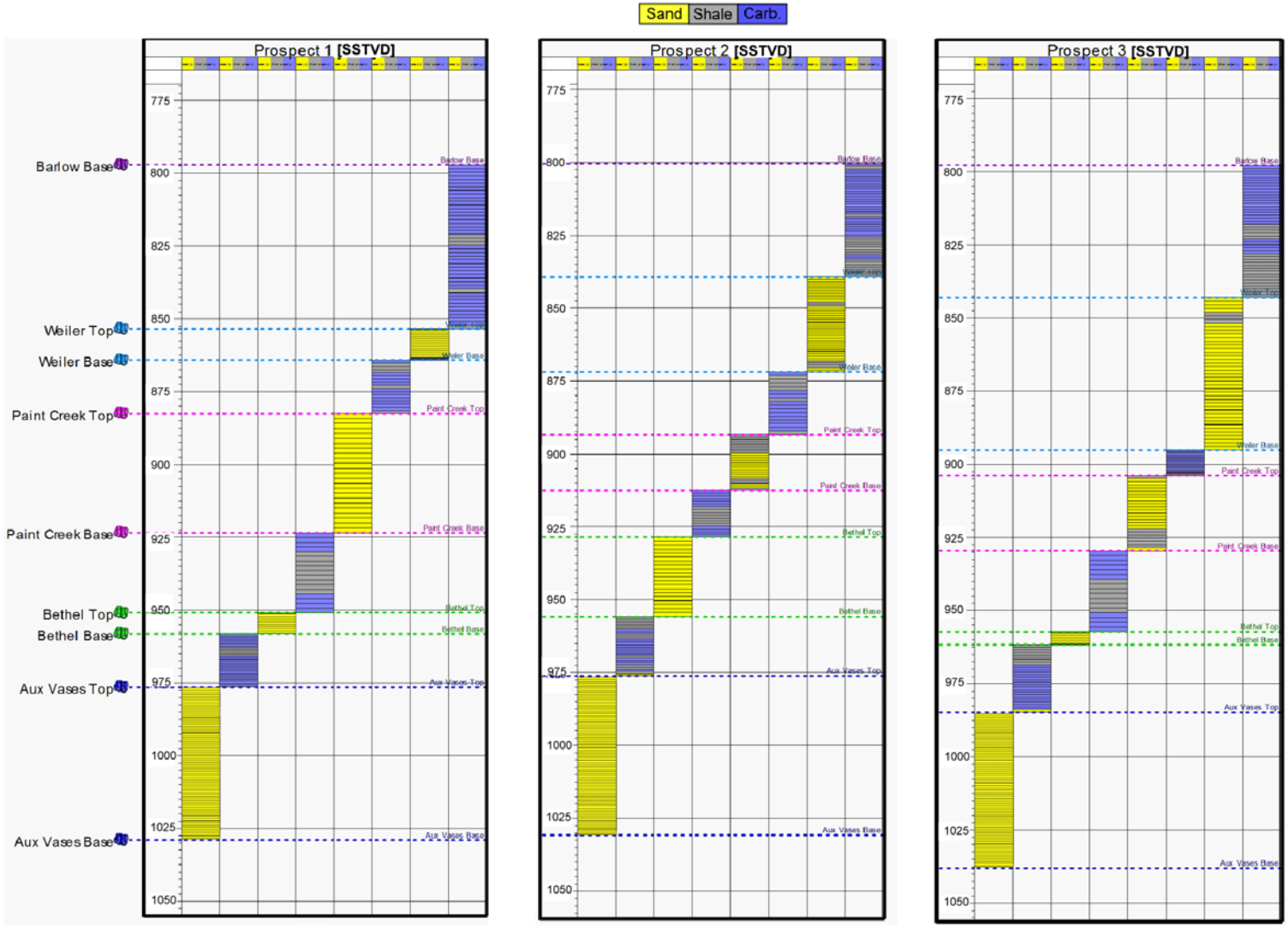

Figure 29: Facies model output logs of the nine prospective wells, each column represents a different depth interval

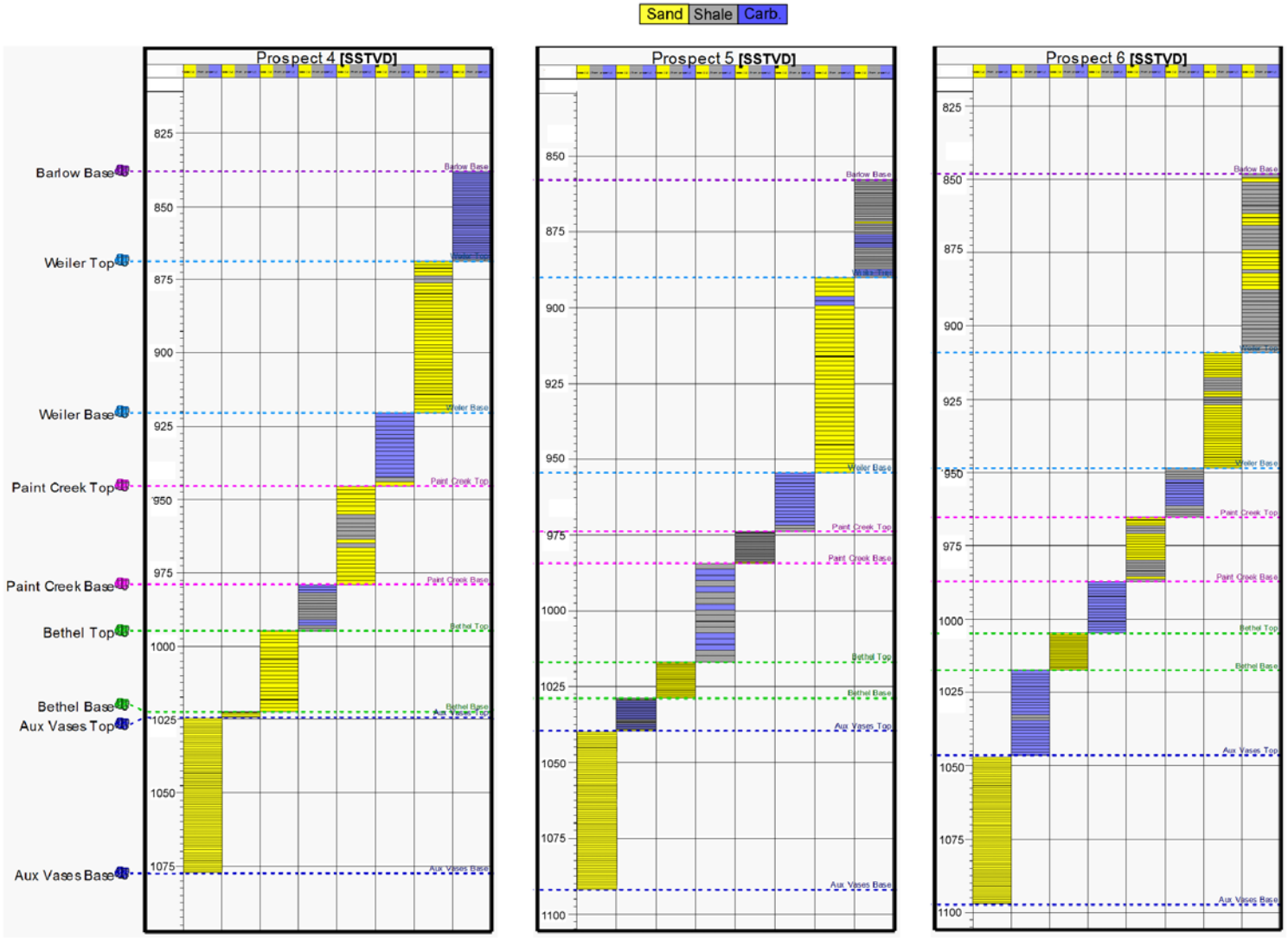

Figure 29 (cont'd): Facies model logs of the nine prospective wells

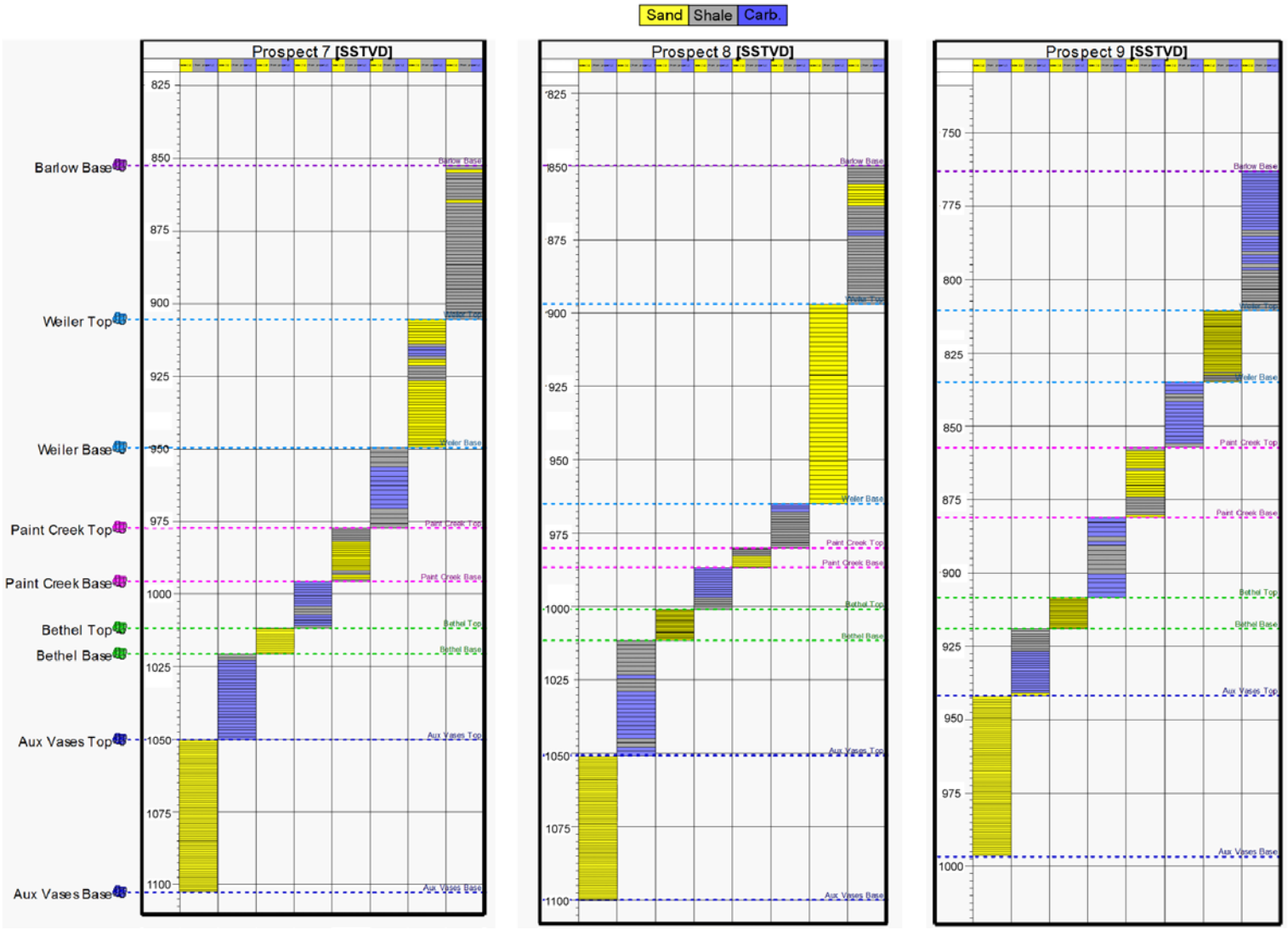

Figure 29 (cont'd): Facies model logs of the nine prospective wells

Table 1: Net feet of sand inside and outside of the four main sand intervals of the prospect wells according to the facies model

Production well prospects									
Well	Facies model net sand								total sand
	above Weiler	Weiler	in between	Paint Creek	in between	Bethel	in between	Aux Vases	
1	0	9	0	40	0	7	0	52	66
2	0	29	0	11	0	27	0	55	77
3	0	48	0	18	0	5	1	53	82
4	0	51	1	26	0	28	3	53	119
5	0	61	0	1	0	11	0	52	83
6	15	33	0	13	0	12	0	51	83
7	2	35	0	12	0	11	0	53	70
8	6	65	0	4	0	10	0	50	95

Injection well prospects									
Well	Facies model net sand								total sand
	above Weiler	Weiler	in between	Paint Creek	in between	Bethel	in between	Aux Vases	
9	0	25	0	18	0	11	1	54	65

use of the surface calculator in Petrel. Net sand in this study represented the portion of the gross sand interval that was of a porosity greater than 0.1 on the 13 porosity logs. Net sand for the 70+ surrounding wells was obtained from the spontaneous potential logs (paper) by determining the shale line (lowest spontaneous potential), determining the farthest log trace reach (highest spontaneous potential and highest porosity value), and then drawing a vertical line at the midpoint between these two extremes. Sand thicknesses that existed between the porosity high line and the midline were totaled for each of the four main sand intervals, the totals representing the net sand of each zone. Net sand amounts for each of the four main sandstone zones were determined from the

digitized logs of the 13 study area wells and the 70+ paper logs of the surrounding wells. Though the two methods for calculating the net sand from logs are different in nature, the same result is produced – the summation of the depth intervals where porosity peaks on the logs. The isopach maps were overlain onto the Loudon field wellspot map (Figures 30, 31, 32, and 33), and the nine prospective well spots were assessed for sand thicknesses. Table 2 displays the results of the net sand thickness assessment. All nine locations have total predicted sand thicknesses greater than the 20 ft required minimum (only the top ~10 of Aux Vases considered). Both methods for analyzing the net sand at each of the nine locations suggest that each of the nine prospects have enough sand to warrant well emplacement. Due to the difference in net sand determination in each method the calculated net sand for each well are different (comparing Tables 1 and 2). Greater amounts of net sand for each interval are predicted by the facies model compared to the net sand isopachs. This could be a reflection of the manner by which net sand was determined in each method. Net sand in the facies model was figured as the total thickness of each interval that had a porosity greater than 0.1 on the porosity log and a gamma ray value less than 60 API on the gamma ray log. Net sand in the isopach method was calculated using the midline method on the spontaneous potential logs and may represent sand that is higher in porosity than the net sand calculated in the facies model. Less net sand is present in the net sand isopachs because potentially a greater cut-off point (greater than 0.1 porosity) may have been represented by the midline used in each of the spontaneous potential logs. Regardless, each method showed that the minimum net sand requirement (20 ft) was met for each of the nine prospective wells.

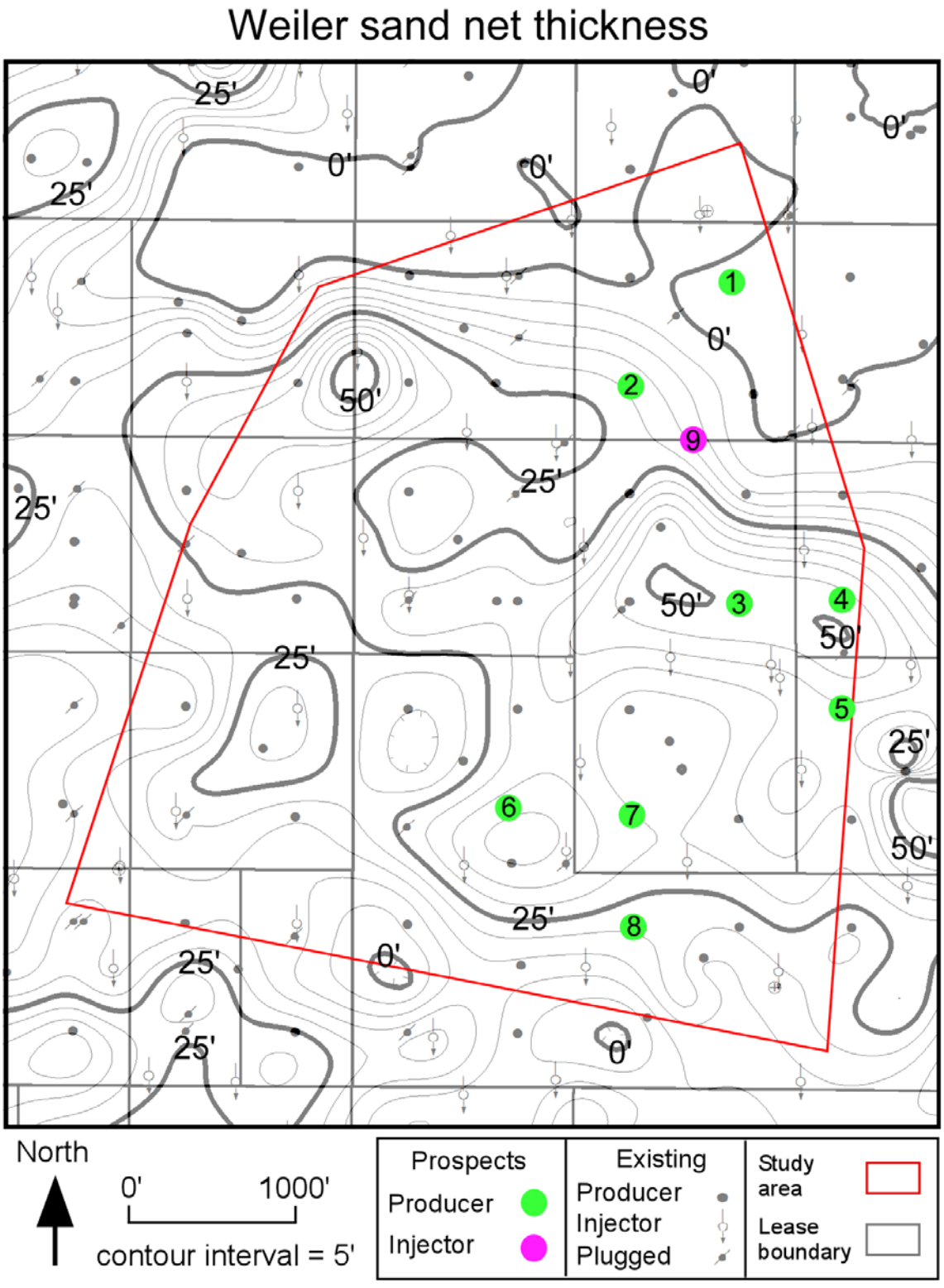

Figure 30: Weiler net sand isopach map overlain on Loudon Field map

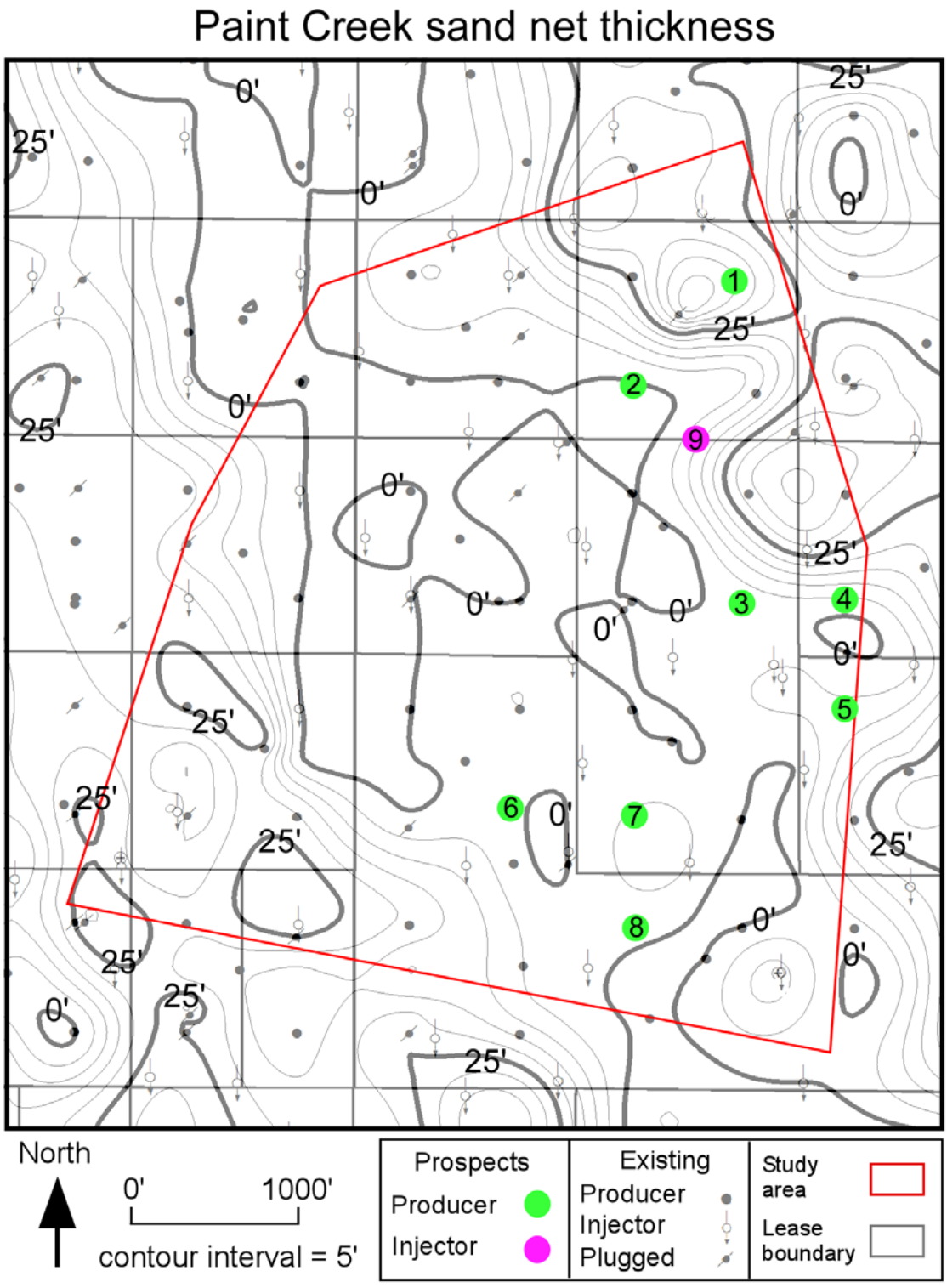

Figure 31: Paint Creek net sand isopach map overlain on Loudon Field map

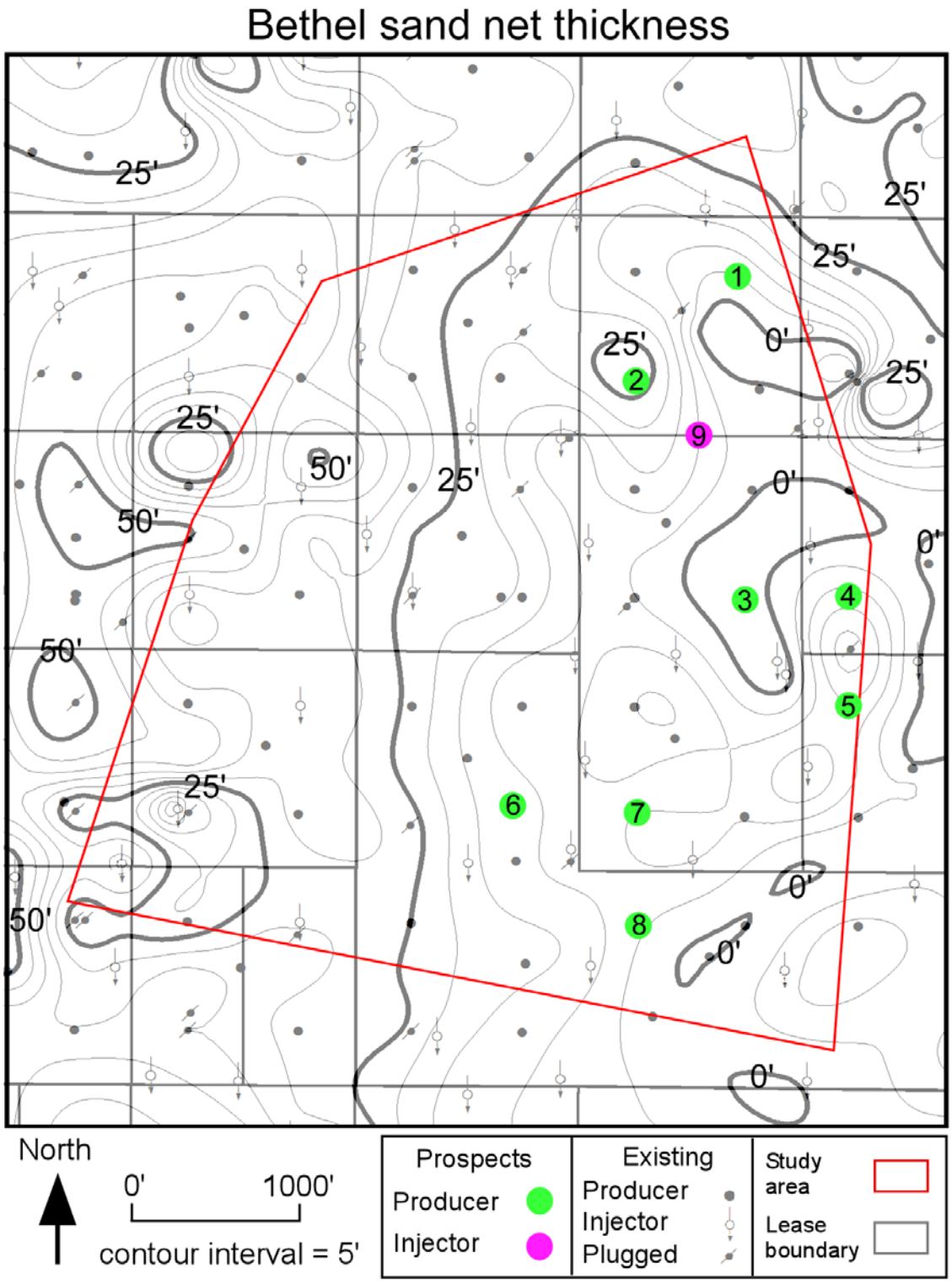

Figure 32: Bethel net sand isopach map overlain on Loudon Field map

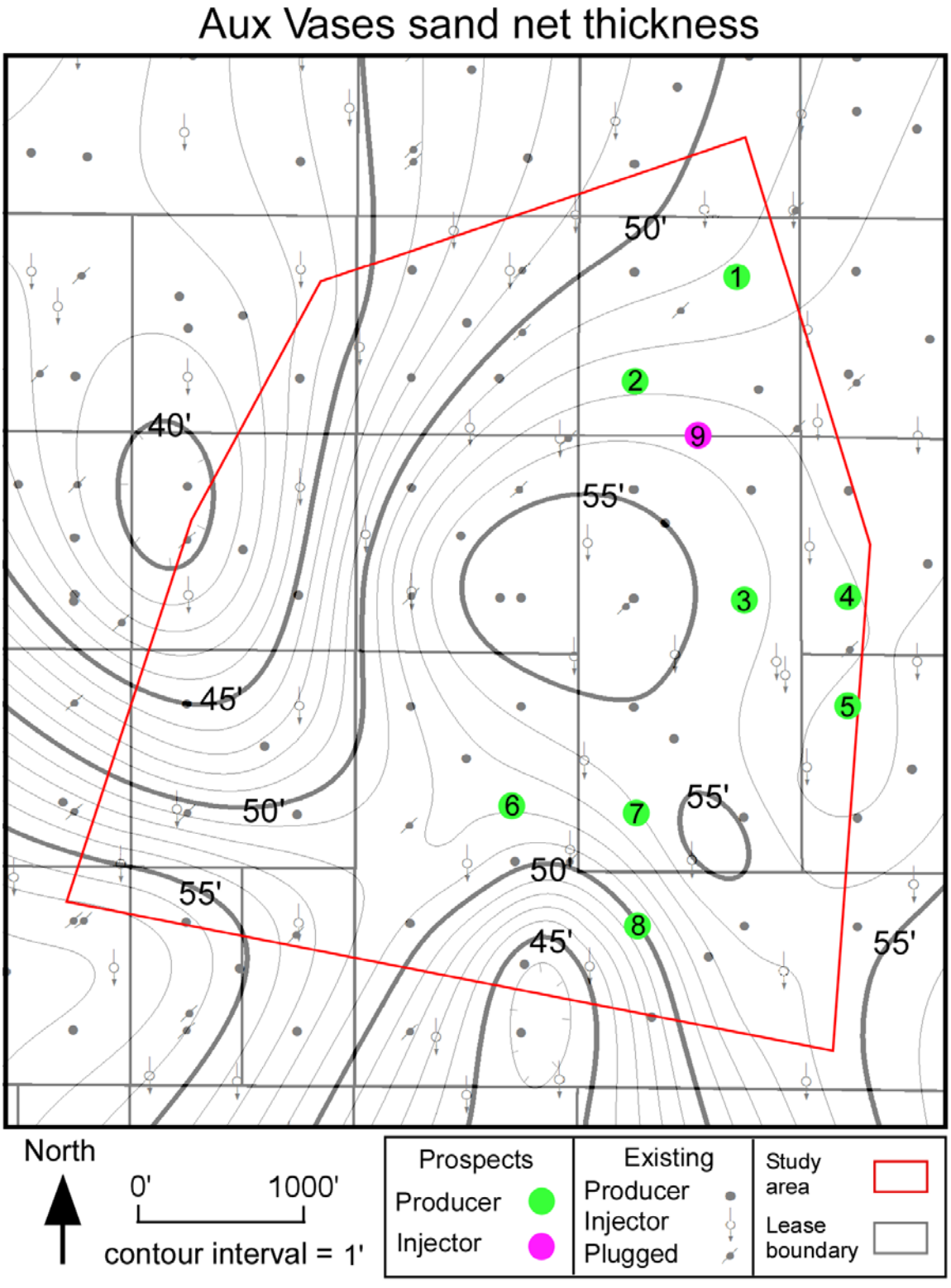

Figure 33: Aux Vases net sand isopach map overlain on Loudon Field map

Table 2: Net sand thickness of the four main sand intervals at the nine prospective wellspots according to net sand picks from spontaneous potential logs of study area and surrounding wells

Production well prospects					
Well	Net feet of sand				total sand
	Weiler	Paint Creek	Bethel	Aux Vases	
1	0	40	6	>10	56
2	19	0	27	>10	56
3	50	2	0	>10	62
4	47	6	12	>10	75
5	40	5	15	>10	70
6	37	1	12	>10	60
7	30	5	10	>10	55
8	22	1	7	>10	40

Injection well prospects					
Well	Net feet of sand				total sand
	Weiler	Paint Creek	Bethel	Aux Vases	
9	13	9	10	>10	42

Porosity model discussion

To analyze the ability of the porosity model to indicate sandstone facies another model was constructed. The goal of the model was to compare porosity model values with facies model values to discern which porosity values did not represent a sandstone facies. Using the log calculator function a new comparison log was created that assigned values of good, bad, and not applicable to grid cells based on the values from the porosity and facies models. If a log interval was designated sandstone on the facies log, had a

porosity greater than 0.1 on the porosity log, and had a value less than 60 API on the gamma ray log, then the log interval on the comparison log was designated “good” (good indicator of sandstone). If a log interval was designated sandstone on the facies log, had a porosity greater than 0.1 on the porosity log, and had a value greater than 60 API on the gamma ray log, then the log interval on the comparison log was designated “bad”. If a log interval was designated shale or carbonate on the facies log, then the log interval on the comparison log was designated “not applicable”. The resulting log was used in conjunction with the petrophysical modeling process to populate 3D models using the three types of boundary scenarios with a 20x20x1 ft (on average) grid cells. Results of the three models are displayed in Figures 35, 36, and 37. Lines of cross section for the three models are displayed in Figure 34. Histograms of the cell value distributions in each model produced by Petrel were used in calculating the percentages of “good” and “bad” cells. In the non-partitioned model 86% of the cells that were designated either good or bad (disregarding the cells deemed not applicable) received a value of “good”, meaning 14% of the porosity model cells had porosity values greater than 0.1 but did not qualify as a sandstone in the facies model due to a gamma ray log value greater than 60 API units. In the zone-partitioned model 18% of the cells were assigned a “bad” value. The sandstone surface partitioned model had by far the greatest percentage of “bad” cells relative to the other two models. 49% of the model cells were deemed “bad”. The Aux Vases zone was omitted from the percentage calculations for the sandstone surface partitioned model because cells in that zone were 100% sandstone facies, making analysis of the zone unnecessary. With the Aux Vases cells included in the percentage

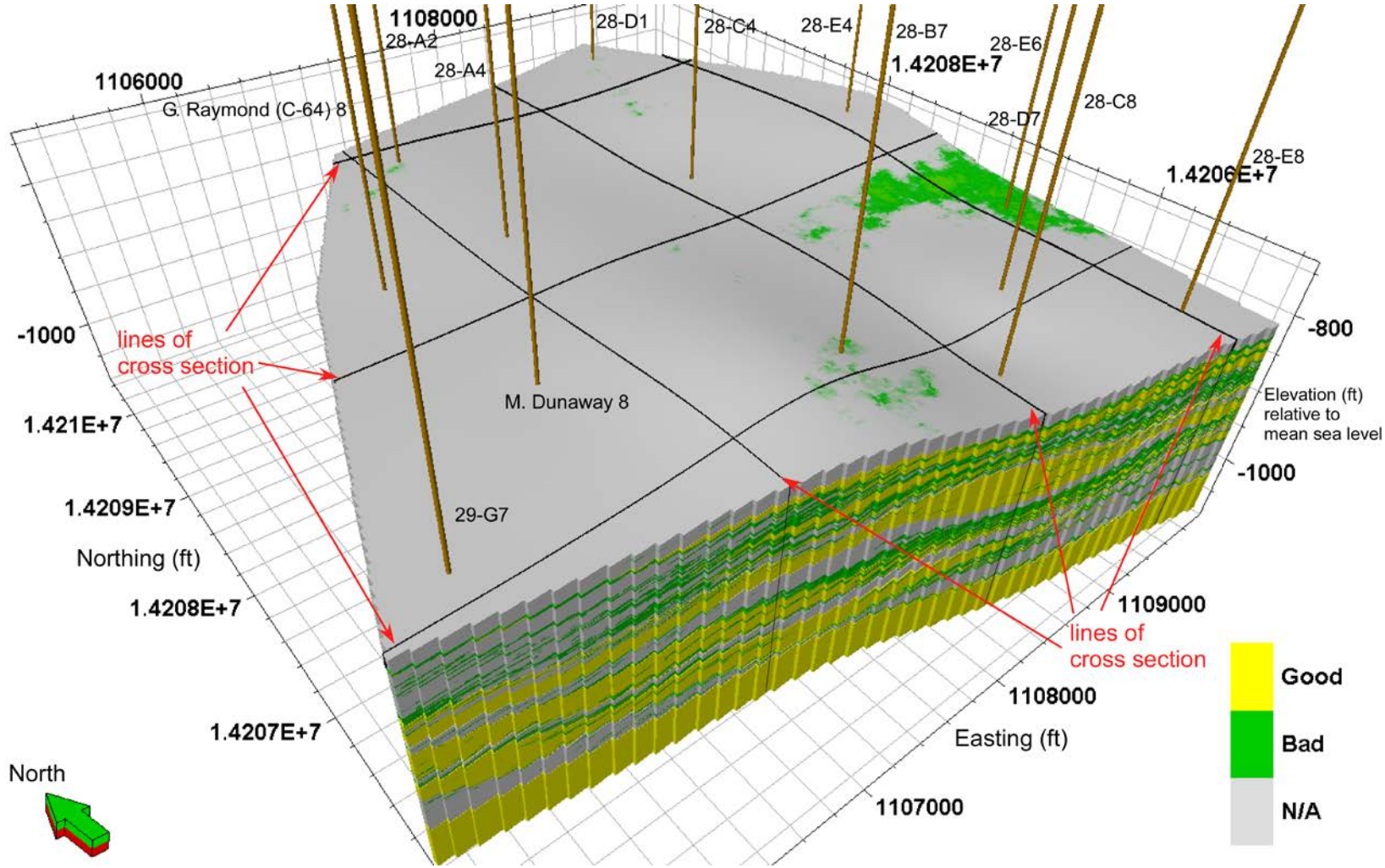

Figure 34: Facies/porosity comparison model showing lines of cross section used in Figures 35, 36, and 37

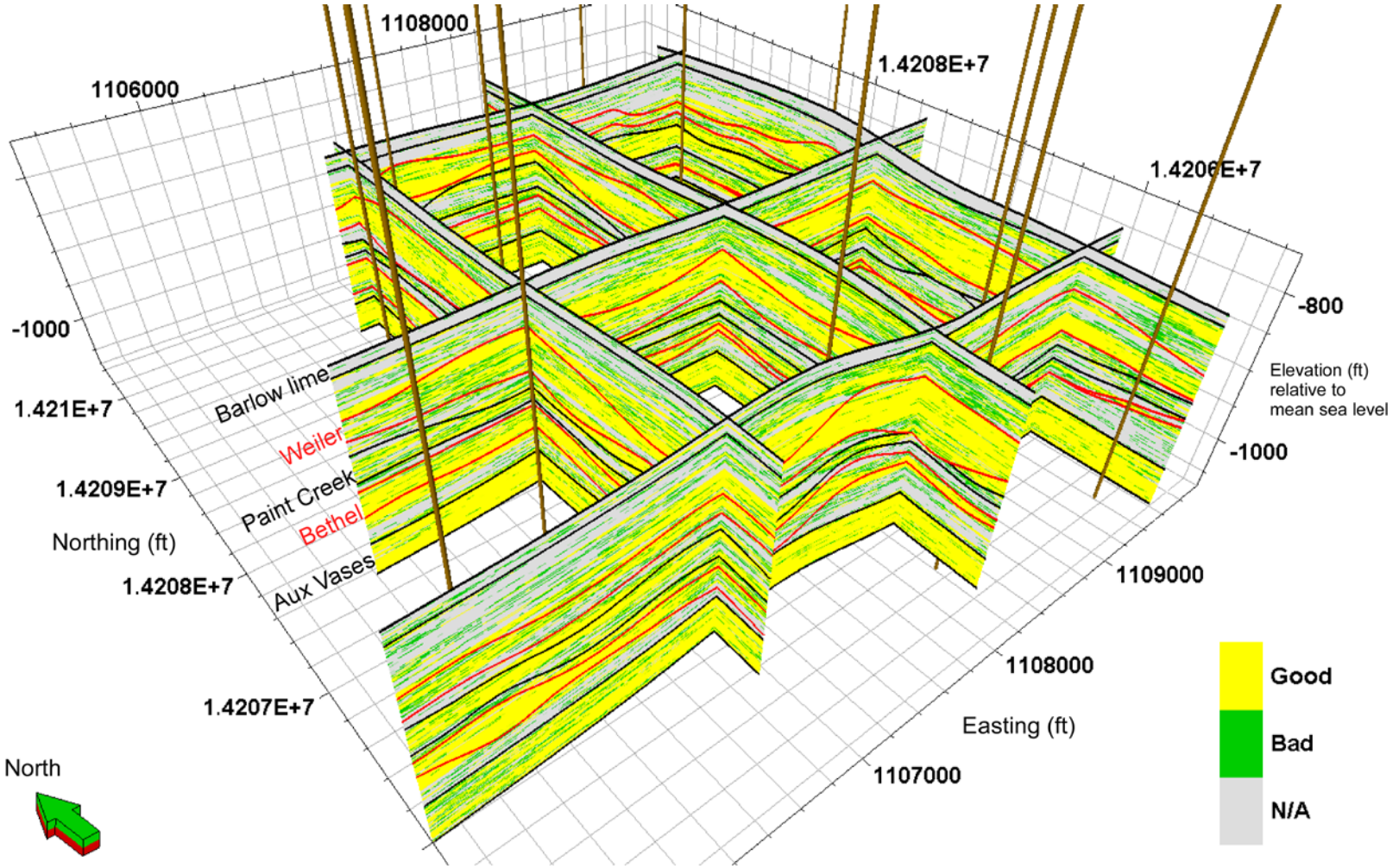

Figure 35: Non-partitioned facies/porosity comparison model, no surfaces between the surfaces of the top of the Barlow and the Aux Vases base controlling assignments of cell values by the algorithm

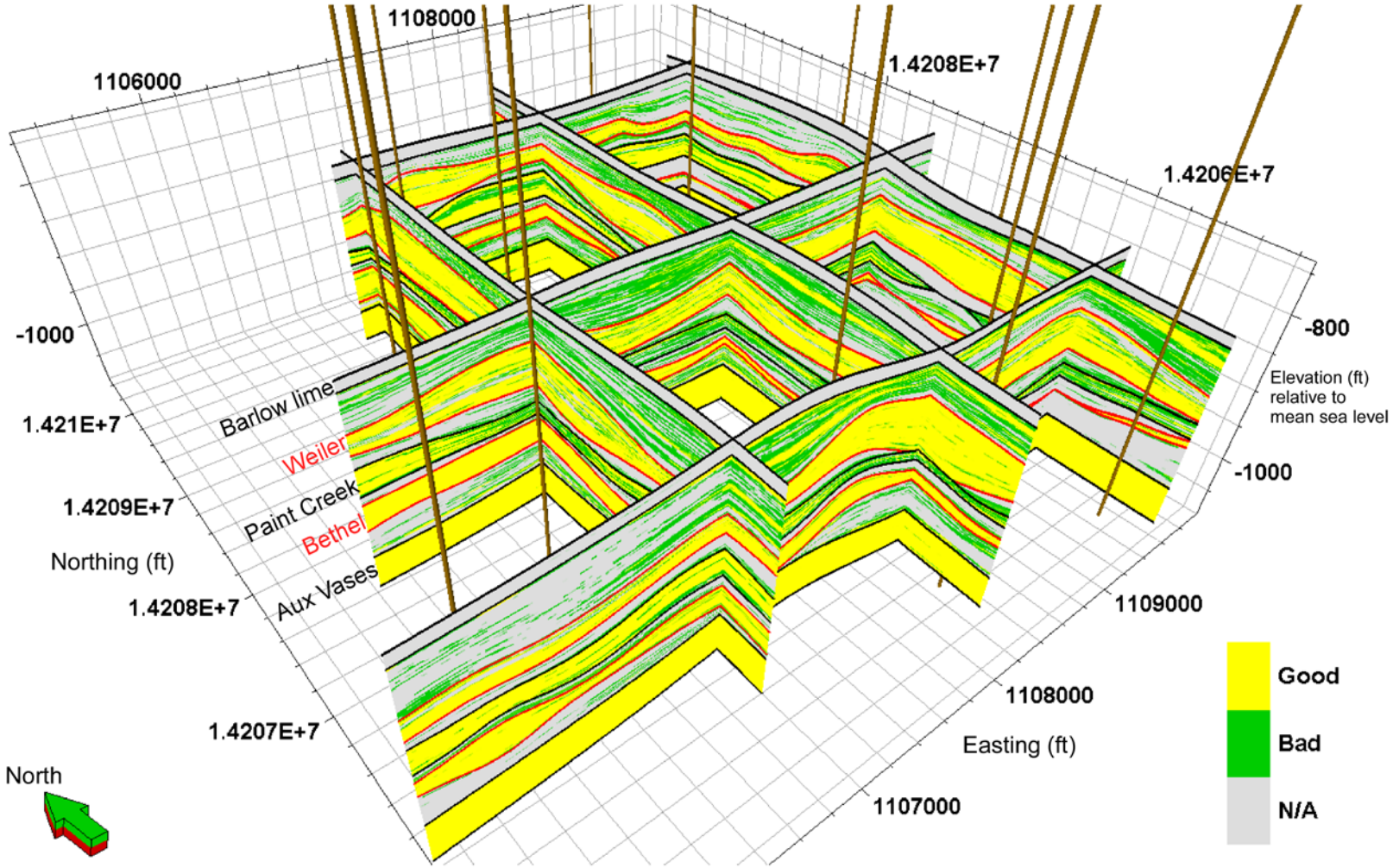

Figure 36: Sandstone surface partitioned facies/porosity comparison model, the surfaces of the Barlow and the four main sands partition the model and control the algorithm in assigning cell values

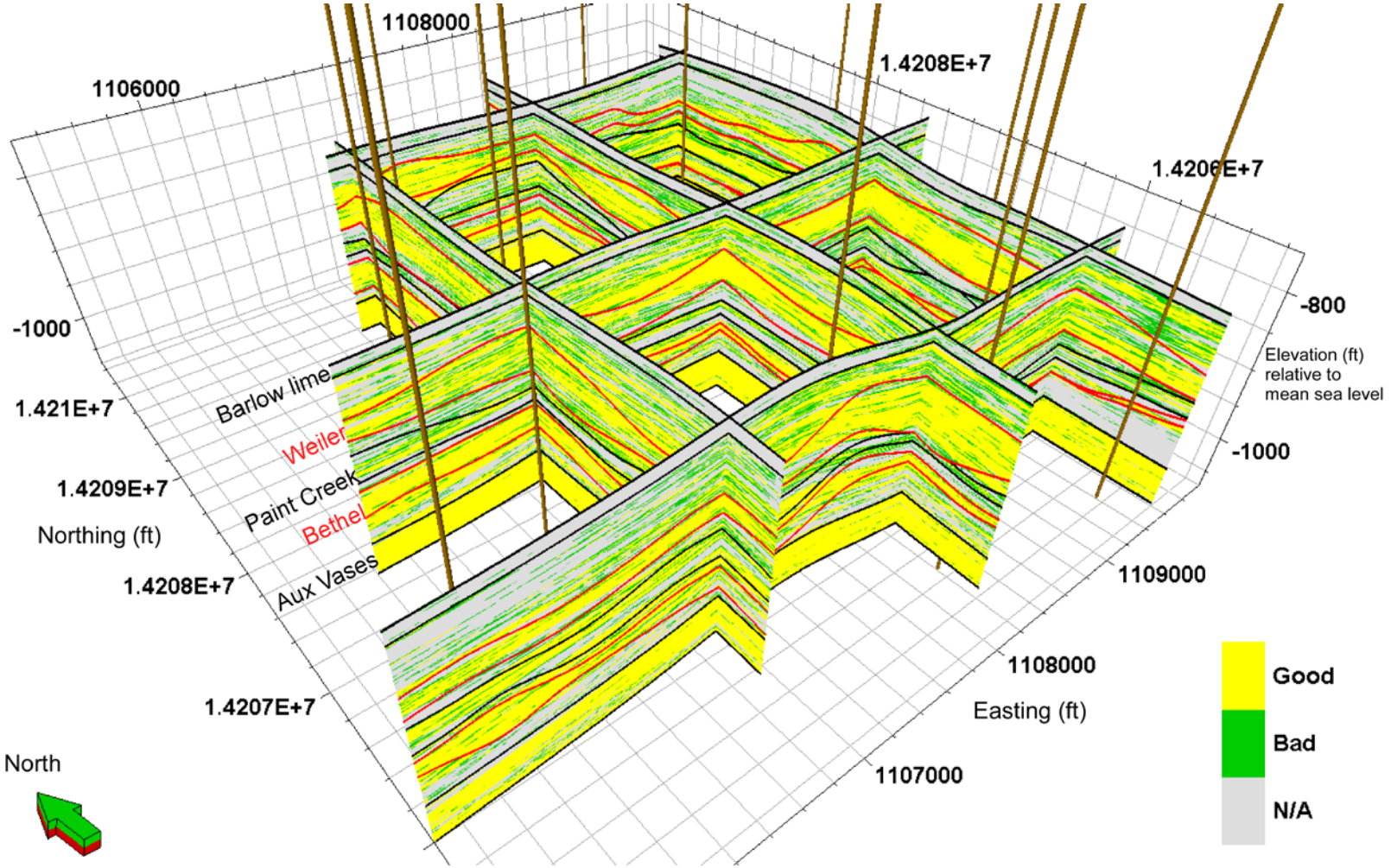

Figure 37: Zone-partitioned facies/porosity comparison model, surfaces midway between the four main sands partition the model and control the algorithm in assigning cell values

calculation for the sandstone surface partitioned model the “good” cell percentage increases to 63%. This is still significantly lower than the “good” cell percentages provided by the non-partitioned and zone-partitioned models (86% and 82%, respectively). An increase in interior model partitions is coincident with an increase in “bad” cell values. The increase in the amount of interior model boundaries from the non-partitioned model to the zone-partitioned model and ultimately to the sandstone surface partitioned model may be the cause for the increase in “bad” cell designations by the algorithm from one model to the next. Since the grid cell assignments in each of the three models is an interpretation produced by the algorithm, the most reliable tool by which to assess the porosity model’s ability to indicate sandstone facies may be the 13 analysis logs (Figure 38). The analysis logs represent the analysis of the facies log, porosity log, and gamma ray log, which are based on well data at the wellbore as opposed to the interpolation processes of an algorithm from some distance away from the wellbore as is the case for cell values located anywhere in the model except at the well. Table 3 displays the total feet of “good” and “bad” intervals in the facies/porosity comparison logs of each of the 13 digitized well logs. The average percentage of “good” thickness in the 13 wells (82%) is the same as the percentage of “good” cells in the zone-partitioned facies/porosity comparison model. This may be an indication that the zone-partitioned model is the most accurate of the three vertical boundary scenario facies/porosity comparison models.

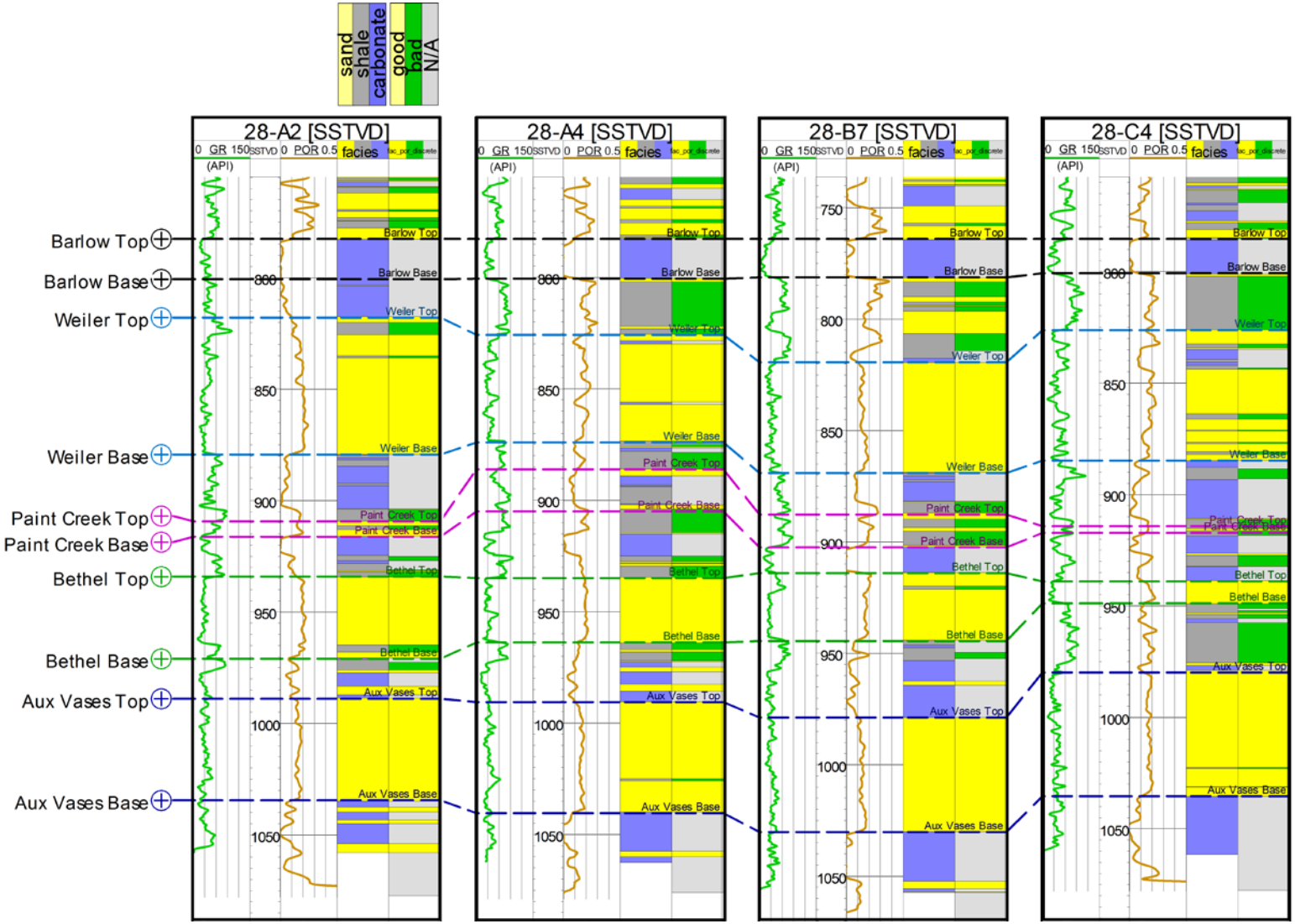

Figure 38: Facies/porosity comparison logs (right) of the 13 study area wells

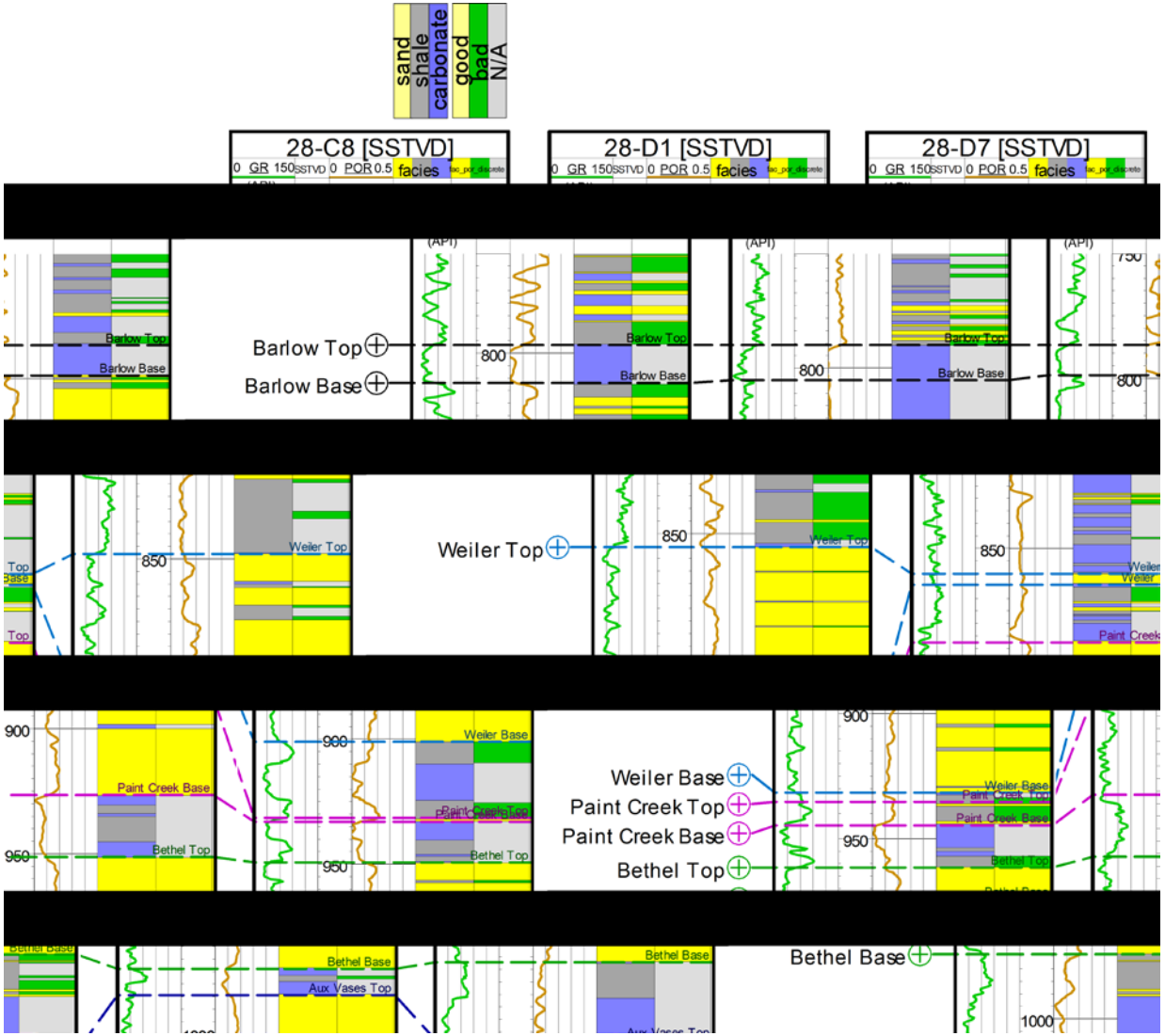

Figure 38 (cont'd): Facies/porosity comparison logs (right) of the 13 study area wells

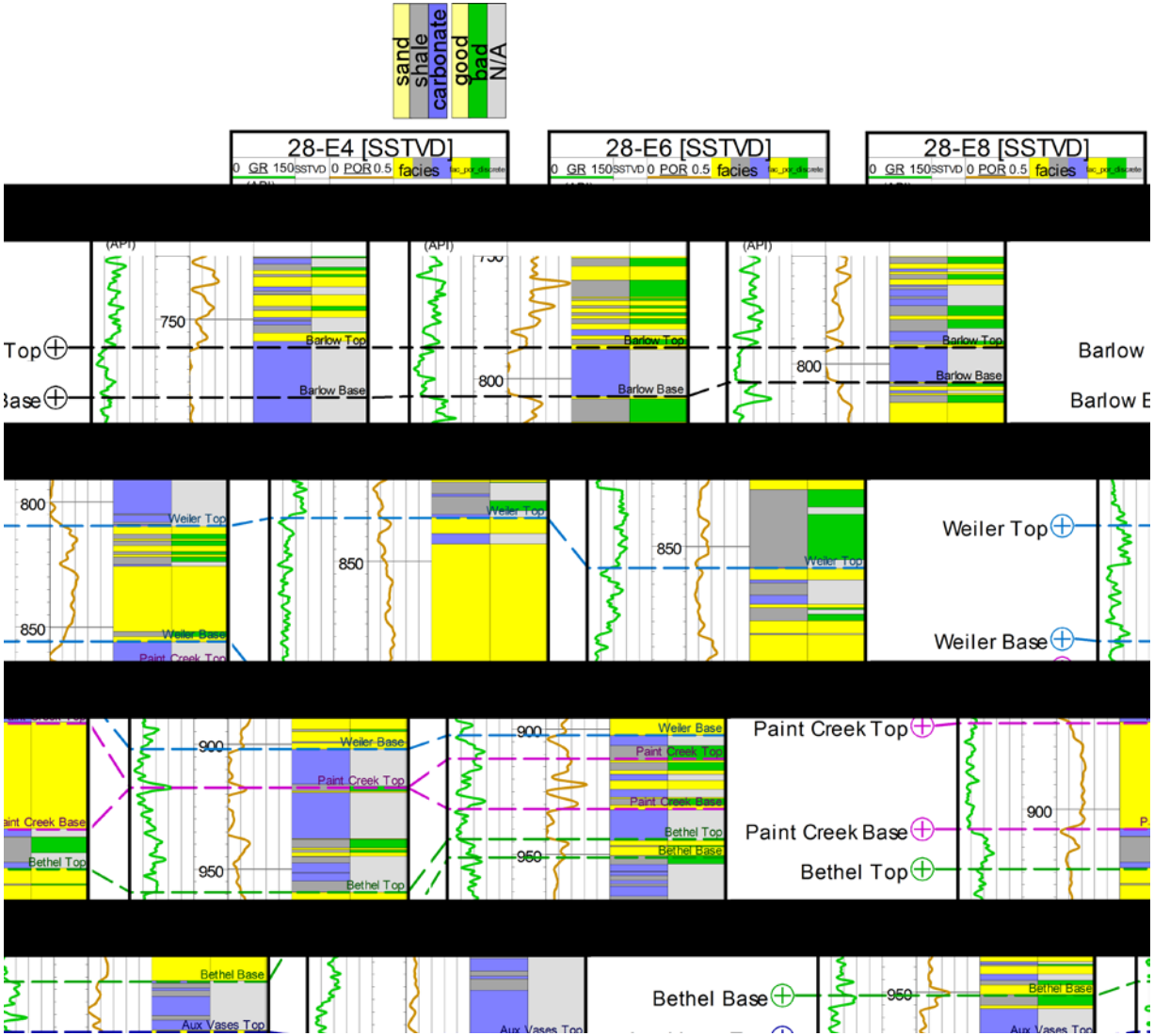

Figure 38 (cont'd): Facies/porosity comparison logs (right) of the 13 study area wells

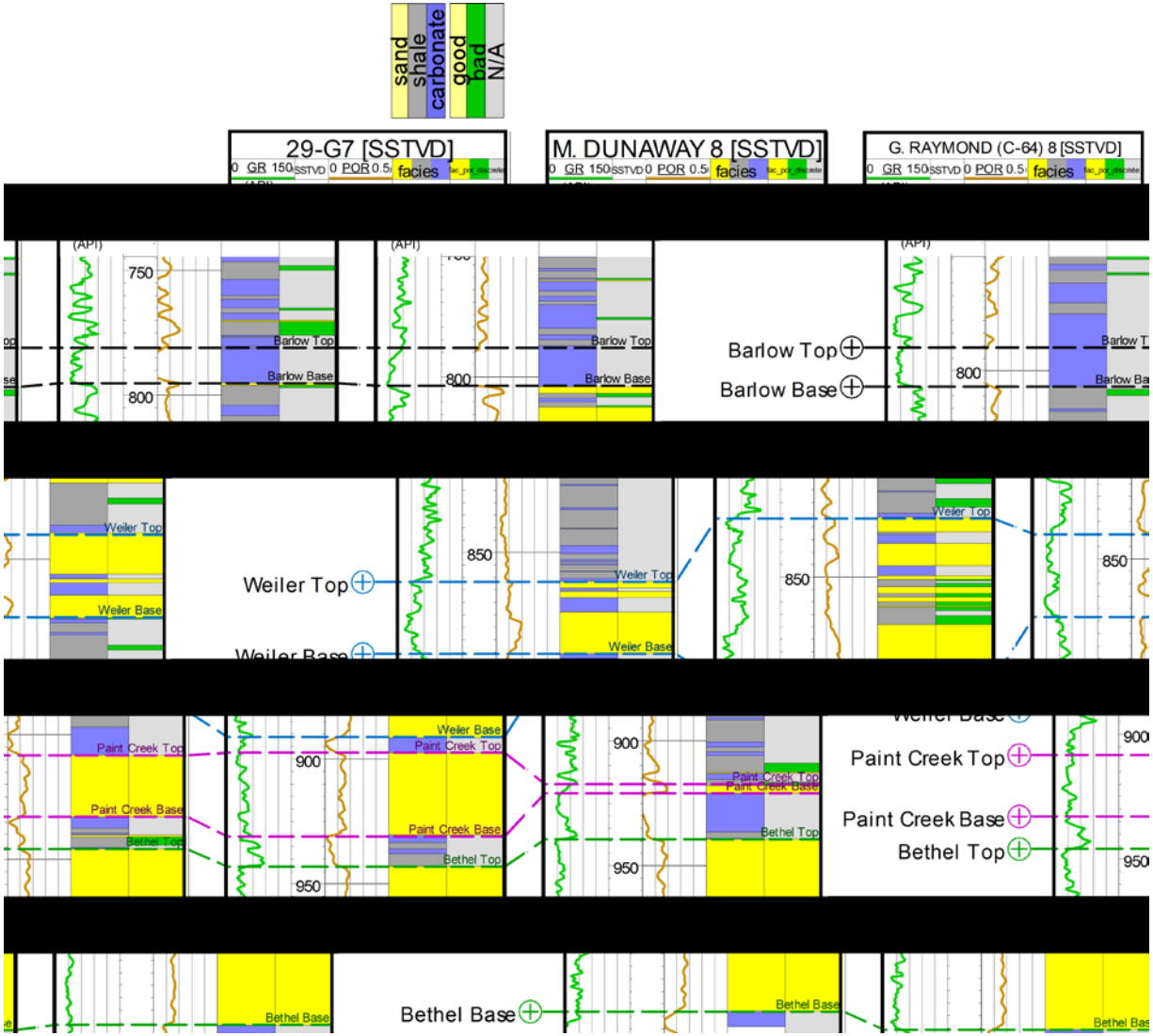

Figure 38 (cont'd): Facies/porosity comparison logs (right) of the 13 study area wells

Table 3: Feet of "good" and "bad" thickness in the 13 study area wells

Well	Feet of "Good"	Feet of "Bad"	Percentage "Good"
28-A2	139	21	87
28-A4	138	63	69
28-B7	147	37	80
28-C4	112	66	63
28-C8	148	53	74
28-D1	118	12	91
28-D7	118	27	81
28-E4	148	22	87
28-E6	134	20	87
28-E8	107	44	71
29-G7	89	5	95
M. Dunaway 8	170	18	90
G. Raymond (C-64) 8	133	12	92
AVERAGE	131	31	82

Sources of error

Possible sources of error in the building of the models include log values and reported xyz coordinates. Occasionally, log values (especially true for spontaneous potential logs) will become "washed out" to a certain degree due to signal interference by an over-saline or otherwise chemistry altered solution in the well. This is most times caused by waters dumping into the wellbore from the Tar Springs, a sandstone approximately 90 feet in thickness that sits roughly 200 feet above the Weiler. The most dramatic cases of signal interference result in a well trace that more closely resembles a vertical line, having a low range of values on the x-axis. All logs in this study were

examined to ensure that measurements made by the logging tool were not distorted by interference. Logs that showed signs of interference were not used.

Coordinates including elevation for the location of the 13 wellheads were obtained from the Illinois State Geological Society, who received the information from the surveyor who located the original drilling site. The reported xyz data are the original "staked" position on the land surface prior to drilling operations. A common occurrence at Loudon is the "moving of the stake" to accommodate for the space requirements of the drilling rig. This not only changes the xy location, but in some cases drastically changes the depth component. For example, a new wellspot for a future water injection well was originally staked on the side of a hill, and rather than fill in the bottom of the hill with soil from the top of the hill to make a flat work area at the location of the wellspot on the side of the hill the decision was made to remove the side of the hill altogether and make the new wellspot location the same elevation as the bottom of the hill. This maneuver dropped the original staked location by approximately 30 feet, but the elevation correction was never reported. Later, a conspicuous bulls-eye on a structure map brought to light the mishap.

V. SUMMARY/CONCLUSION

The primary goal of the project was to build a 3D facies model in Petrel and, using the model to determine sand thicknesses of the various sand intervals, locate additional production targets. Various cell sizes, algorithms, and vertical boundaries were used in building various facies models. Each different model was assessed for advantages and disadvantages with the objective of determining the most accurate model to use in the net sand estimation exercise. Due to the amount of well control (13 digitized well logs and 70+ paper logs from surrounding wells) used in building the interior model partitions the sandstone surface partitioned model, while somewhat restrictive regarding lateral facies change, was determined to be the most appropriate model to use in exploring Loudon Field for prospective sand targets. Nine prospective well locations were determined suitable for drilling. The two methods used to determine net sand potential at each of the locations differed in technique but showed the minimum net sand thicknesses required for well emplacement were met at each prospective location.

The other goal of the project was to assess the ability of a Petrel porosity model to predict sandstone facies. Percentages of cells indicating a good representation of sandstone varied depending on which of the three vertical boundary scenarios was used in the model. Examination of the facies/porosity comparison logs showed that the percentage of the log that represented a good sand indicator by the porosity log (82%)

was the same as the good sand indicator percentage of the zone-partitioned model.

Data provided by both the facies and porosity models were largely a product of interpolation by the modeling algorithm, so error in cell assignments is assumed to exist in the models to a certain degree. The most reliable data in the models are the cell values at the locations of the wellbores because the data were generated by the logging tool. The validation exercise that involved the exclusion of certain well logs and rerunning of the facies models showed that the cell assignments produced by the algorithm in the two examples were at least ~80% accurate. Though modeling in Petrel provides a reasonable interpretation of reservoir rock characteristics, efforts incorporating Petrel-based modeling should involve consideration of the potential error in cell values a given distance from log-truthed well data.

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