Unconventional Reservoir Characterization with Upscaled Permeability Using SEM*

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Abstract

Conventionally geoscientists have used optical microscopy for micro-tectonics, mineralogy, paleontology and so forth. The deeper we go, the more knowledge flourishes and every next level of magnification teaches us more. However there is a strict limitation of optical microscopy; the wavelength of light does not allow us to go further than fractions of a micrometer; as a result, we cannot inspect unconventional fine-grained, tight-fractured reservoirs with optical resolutions. On the other hand, Scanning Electron Microscopy (SEM) provides a good resolution in the scale of a few nanometers; this is enough for even shales. From literature, we know that shales are organically rich and fractured rocks. Indeed, SEM studies show that organics are distributed heterogeneously within inorganic matrix and fractures exist randomly in shales. Capabilities of SEM comes with a disadvantage; SEM can only represent a few square nanometers of a rock, but we deal with hundreds meters long reservoirs in oil and gas industry. An upscaled permeability value characterizing the entire heterogeneous and anisotropic shale reservoir can be a practical solution to such problem. SEM images are digitized in grid layouts. Each grid cell correspond one sub-element; organic, inorganic or fracture. Porosity and permeability of each sub-element is defined in a Computational Fluid Dynamics (CFD) simulator and the production rate for that digitized model is calculated. At the next stage, two modules of software we coded generate different scenarios imitating the base model. Such variations include total random fractures and fractal based branching fractures. By testing production rates of newly created models we determine a dependable production rate range because we have obtained different and extreme cases that are possible to be observed in different images of the same sample. In addition, at the final stage, all models are represented with an upscaled permeability value, yielding the best-matched production rate curves. The upscaled permeability value can be used to define the whole reservoir from which the samples are taken. As a

result, we eliminate the disadvantages of SEM, which can only characterize a couple square nanometers of a reservoir. We suggest a production rate range including the extreme cases and an upscaled permeability value, which can be used to represent the whole reservoir. Hence, we can estimate the economic worth of petroleum reservoirs more accurately.

Introduction

Conventionally geoscientists have used optical microscopy for micro-tectonics, mineralogy, paleontology and so forth. The deeper we go, the more knowledge flourishes and every next level of magnification teaches us more. However there is a strict limitation of optical microscopy; the wavelength of light does not allow us to go further than fractions of a micrometer; as a result, we cannot inspect unconventional fine-grained, tight-fractured reservoirs with optical resolutions. On the other hand, Scanning Electron Microscopy (SEM) provides a good resolution in the scale of a few nanometers; this is enough for even shales. From literature, we know that shales are organically rich and fractured rocks. Indeed, SEM studies show that organics are distributed heterogeneously within inorganic matrix and fractures exist randomly in shales. Capabilities of SEM comes with a disadvantage; SEM can only represent a few square nanometers of a rock, but we deal with hundreds meters long reservoirs in oil and gas industry. An upscaled permeability value characterizing the entire heterogeneous and anisotropic shale reservoir can be a practical solution to such problem.

SEM is based on two principles. First, a sample is bombarded with focused beam of high-energy electrons grid-by-grid, second the signal generated due to the interaction between the sample and the electrons at each point is recorded. Those electron-stimulated samples backscatter some electrons. If a point in the sample contains a high intensity matter, i.e. high atomic number, the reaction of the sample will also be very intense and the sample emits high amount of electrons. On contrary, matters with low atomic number can scatter few electrons because electrons do not bounce back much; rather they are buried deep into the sample. Amount of scattered electrons determines the brightness of that spot in the SEM image. High-density minerals, especially metallic minerals; such as, pyrite, appear brighter. Color of a spot gradually darkens as the atomic number decreases. For organic matter, we observe nearly black color because of their much lower densities with respect to mineral grains. Even more, fractures are black since they lack any matter and any atomic number inside them.

Methodology

SEM images are digitized in grid layouts (Figure 1). Any label and mark on an image from the literature can be removed using image-processing techniques (Figure 2), which are not the subject of this paper, but those applications are employed as well.

Fractures, organics and minerals are recognized based on the color contrasts mentioned in the previous part. After fractures and organics are recognized, a color-simplified image will be ready (Figure 3). This image is converted to an input file of a CFD simulator. Each grid cell corresponds one sub-element; organic, inorganic or fracture (Figure 4). Porosity and permeability of each sub-element is defined in the simulator and the pressure decline curve for that digitized model is plotted. Each of these steps is conducted via a program we created for this study.

For the second part of the study, an effective upscaling method will be held (Cicek et. al., 2014). In this method, many homogenized models, which have the same total porosity with the SEM image model and varying isotropic permeabilities, are generated and their pressure decline curves are compared with the original decline curve (Figure 5). It is suggested to plot homogenized model curves and the original curve in a 3D fashion to catch quick changes and the shifts in the intersection line trend. The homogenized model which best fits the original curve can be used behalf of the original one and the single permeability value of that homogenized model will be the upscaled permeability of the original image and so the upscaled permeability of the reservoir, if the image is a good representative one (Figure 6).

Results and Conclusion

Homogenized model 16, which has a permeability of 246 μD, best fits the original image curve. Thus, the upscaled permeability for the image used is estimated as 246 μD. This value represents the mixture of all heterogeneities in the sample and gives the same simulator results with the complex/heterogeneous models conformably. As a result, we estimated the upscaled permeability value of a reservoir using only a SEM image from the reservoir and eliminated the disadvantages of SEM that can only characterize a couple square nanometers of a reservoir in details. If the image is believed to be a good representative one for the reservoir, the upscaled value will become the upscaled permeability value of the entire reservoir.

References Cited

Cicek, M., D. Devegowda, F. Civan, and R.F. Sigal, 2014, Effective Permeability Upscaling from Heterogeneous to Homogenous Porous Media: in 5th International Conference on Porous Media and Their Applications in Science, Engineering and Industry, ECI Symposium Series, Web Accessed September 14, 2014. http://dc.engconfintl.org/porous_media_V/38.

Jennings, D., 2013, Electron Microscopy of Shale Hydrocarbon Reservoirs: AAPG Memoir 102, 260 p.

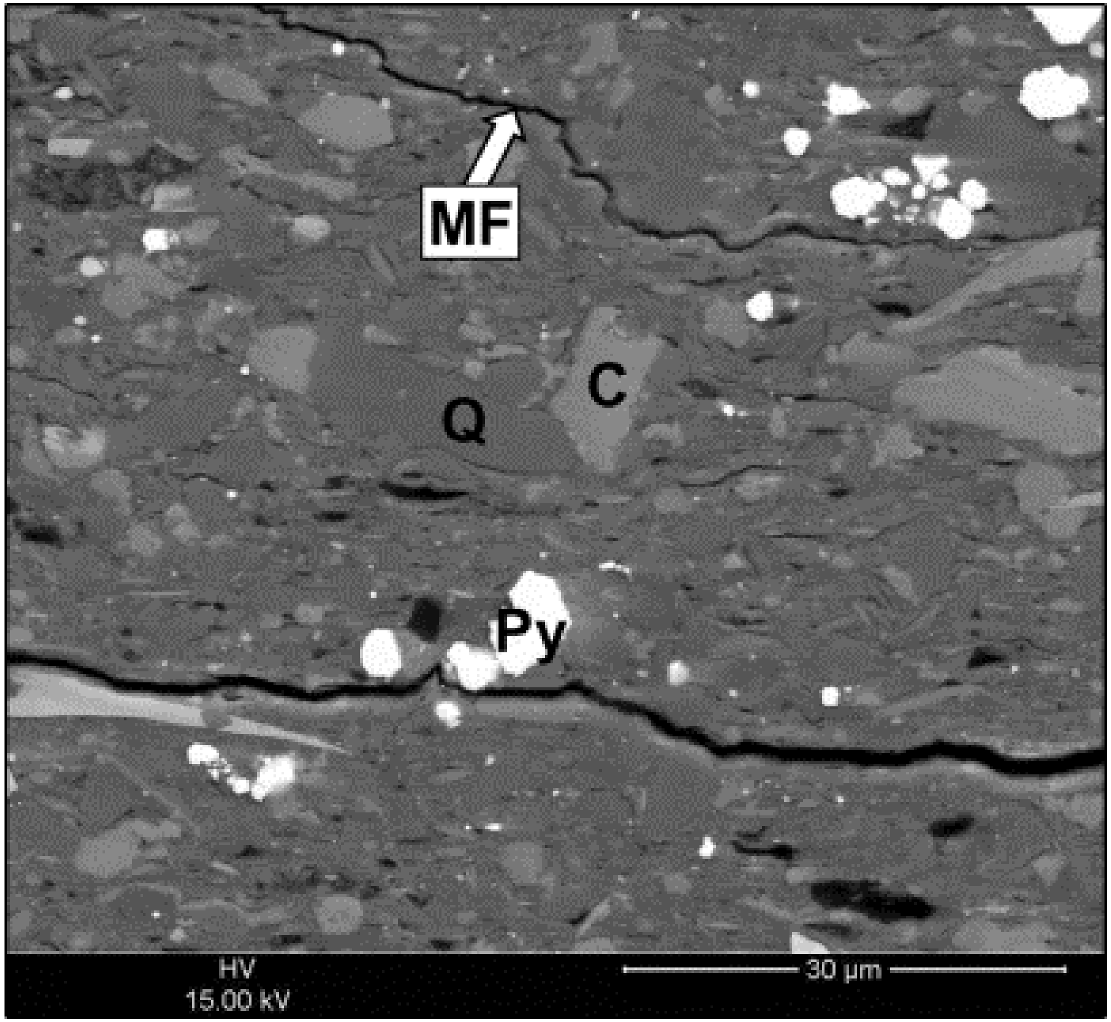

Figure 1. The original image. Adapted from D. Jennings, Core Laboratories. AAPG Memoir 102, Electron Microscopy of Shale Hydrocarbon Reservoirs, p. 188. AAPG©2013, reprinted by the permission the AAPG whose permission is required for further use.

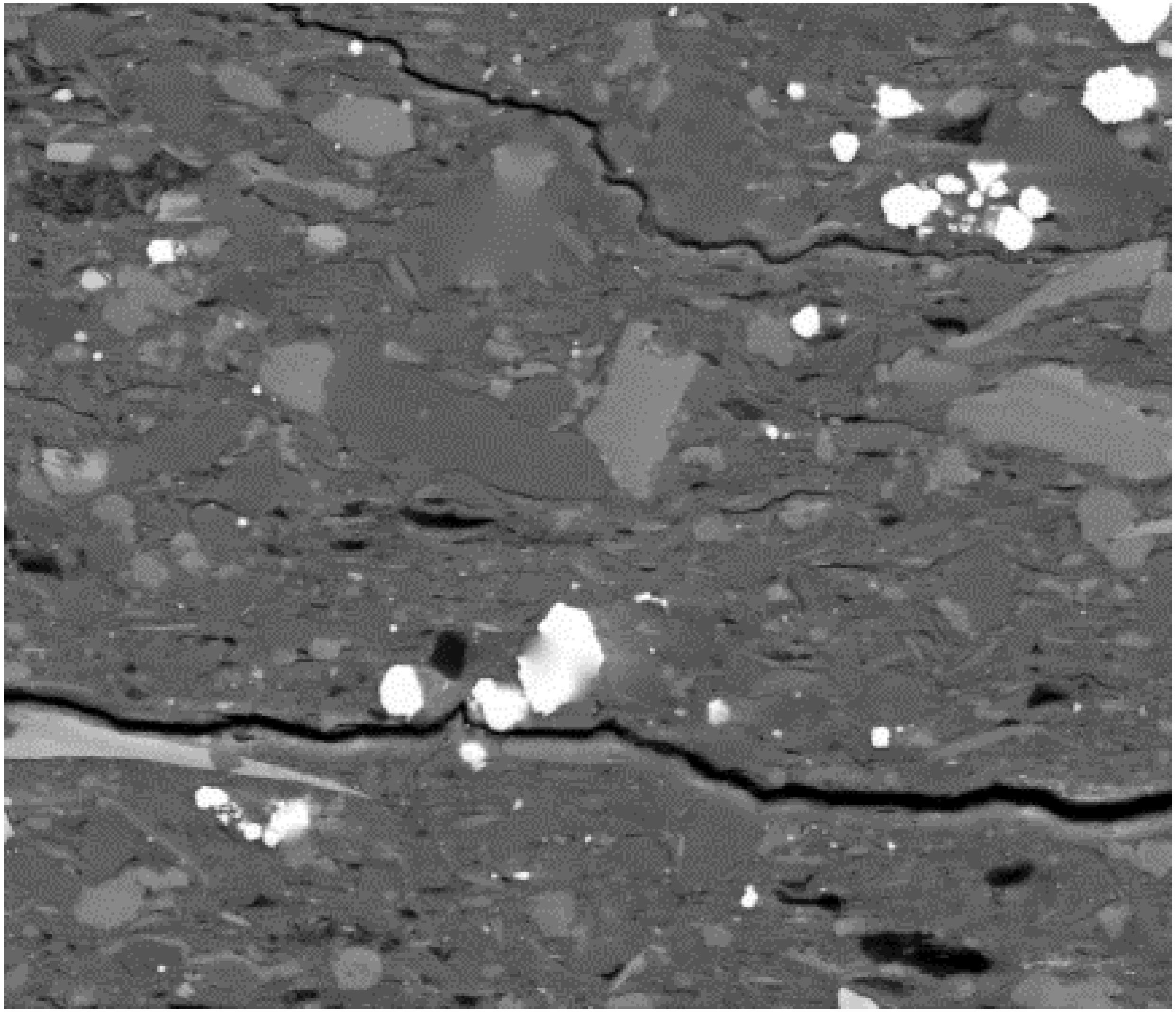

Figure 2. Any artifacts on the original image are removed for further purposes.

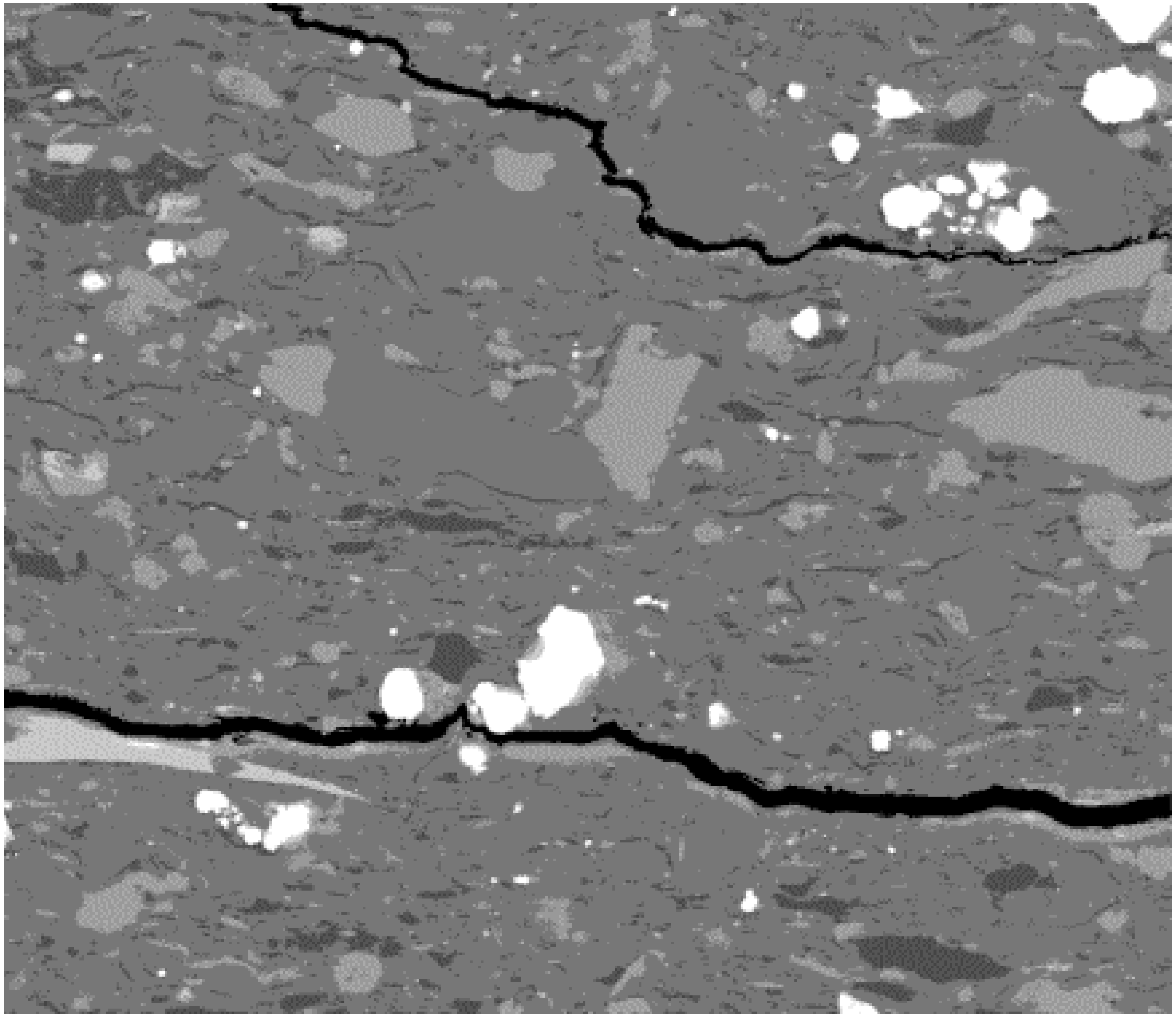

Figure 3. Color-simplified image is prepared. Black lines are fractures, dark gray objects are organic matter and the other brighter objects are various minerals (quartz, calcite, and pyrite).

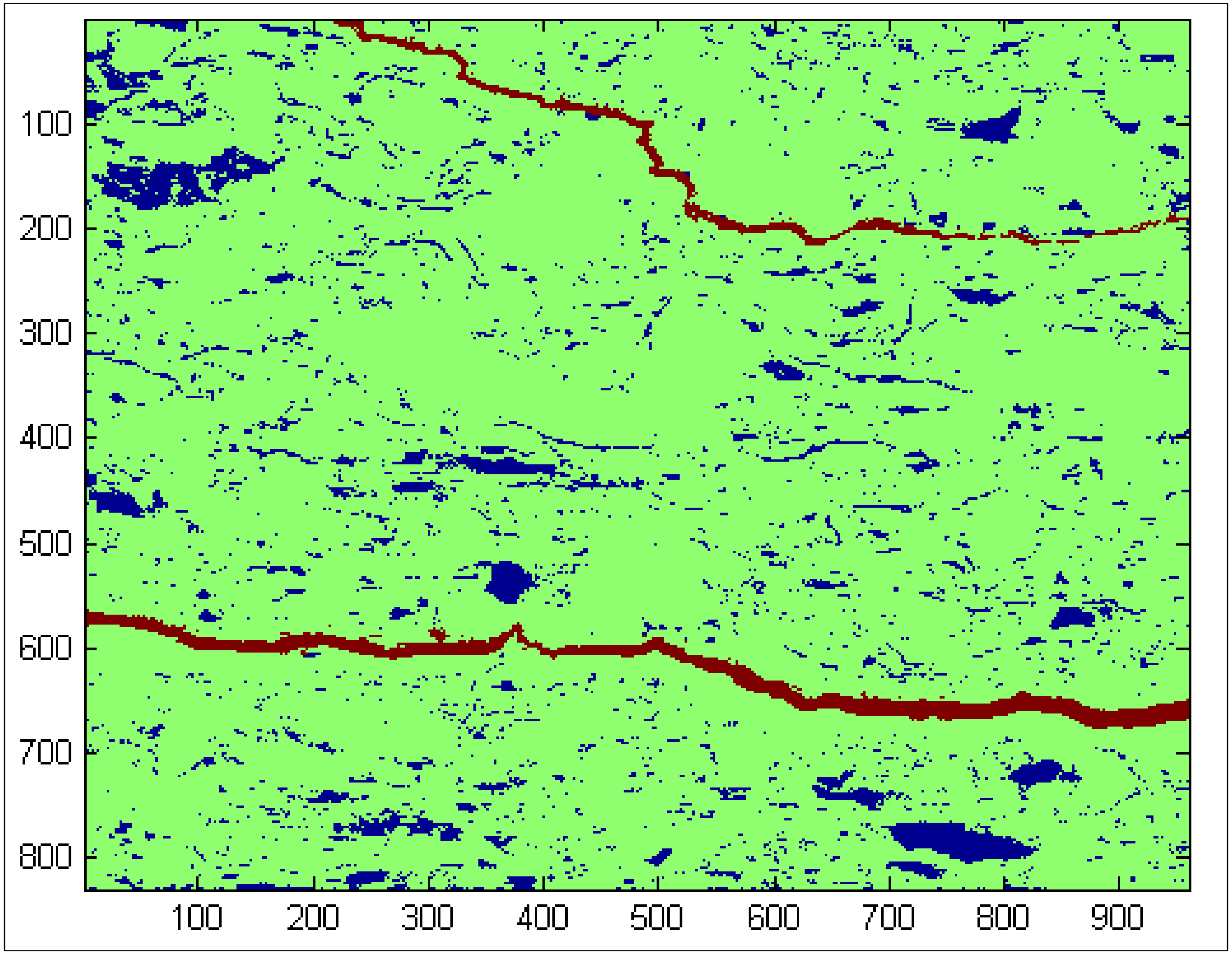

Figure 4. Minerals, organics and fractures are described in the CDF simulator. Red grids are fractures, blue grids are organic matter, and green grids are inorganic mineral matrix.

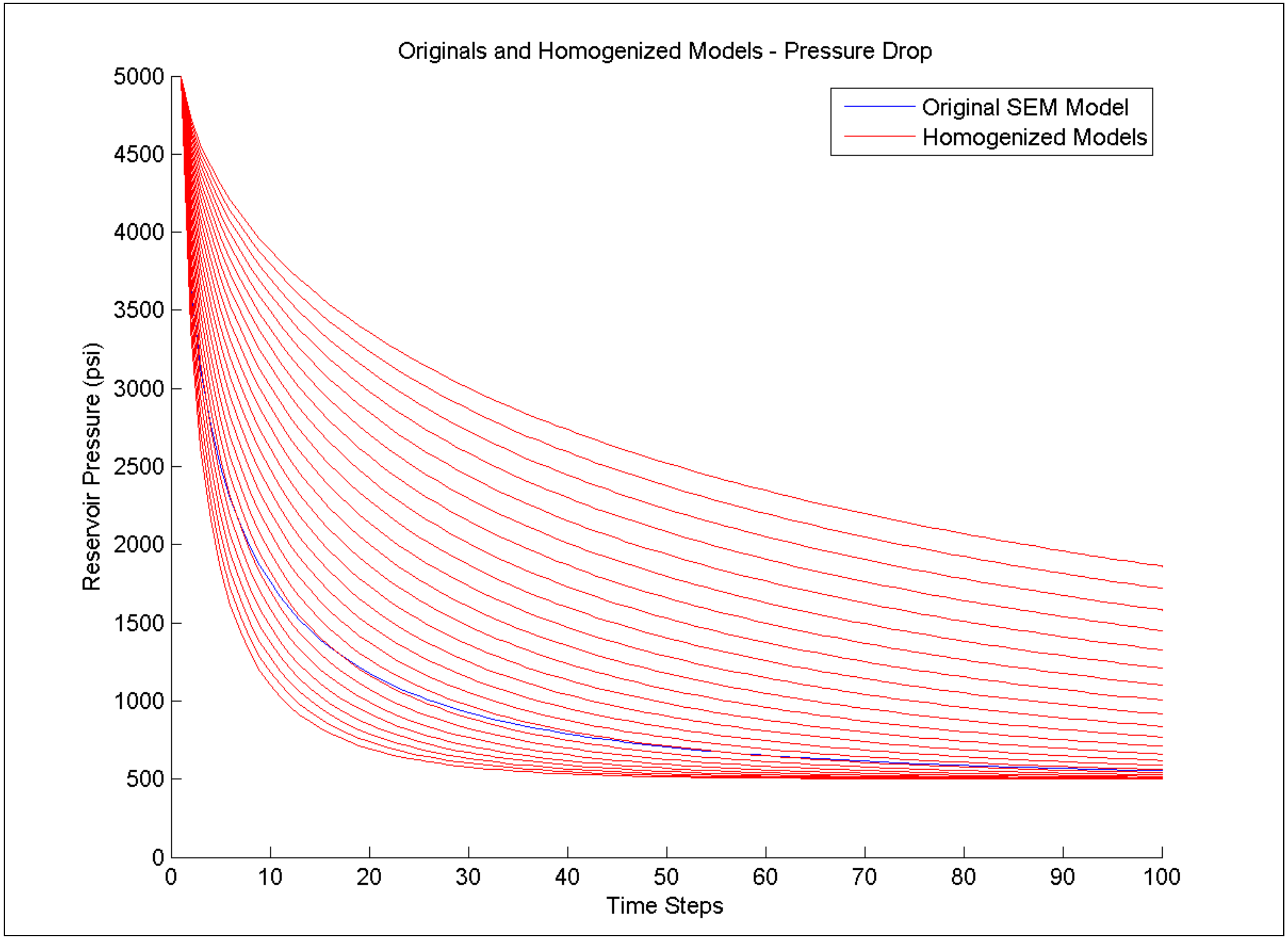

Figure 5. Pressure decline curves for original and many homogenized models are plotted.

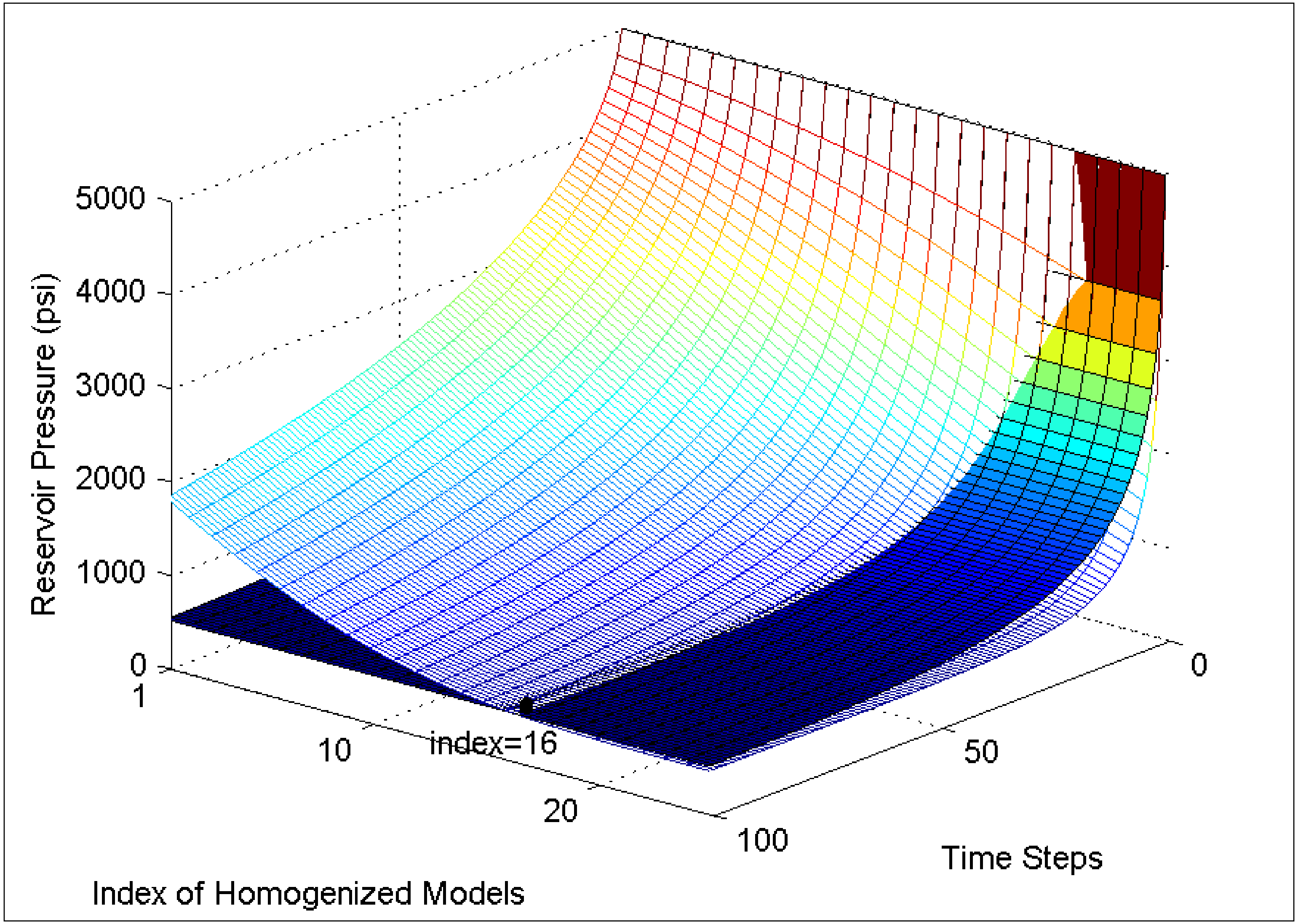

Figure 6. Previous plot converted to a 3D plot.