GEOMODELING: A TEAM EFFORT TO BETTER UNDERSTAND OUR RESERVOIRS

Part 8: Reserves Engineers and Geomodeling

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INTRODUCTION

Computing volumes of hydrocarbons in the reservoirs is an essential task of any asset team. Nowadays, many companies are using geomodels to do these evaluations. After all, considering a geomodel is meant to capture all our data, our knowledge and our assumptions about our reservoirs, it's natural to use it for volume computations. After flow simulation, covered in the previous part of this series, running volumetrics is another important way in which engineers are using geomodels.

The first section introduces the volumetric equation.

The industry didn't wait for geomodels to come along to develop workflows to compute volumes. As such, the arrival of geomodeling might require an asset team to adjust their current volumetric workflow. This is the topic of the second section.

Net-to-gross is an important parameter in volume computations. How should we take it into our geomodeling workflow? Should we model net-to-gross with geostatistical tools? Does it make more sense to recompute the net-to-gross in each cell by applying the cut-offs defining it in the first place? These different questions will be answered in the third section.

A key goal of geomodels is to capture our level of uncertainty about the reservoir characteristics. Several important sources of uncertainty were introduced in the previous papers of this series, as well as how they can be taken into account in the geomodel. These different uncertainties must be considered when running volumetics. The last section of the present paper will summarize them.

Taking into account uncertainties will lead to generating a range of volumes instead of a single, deterministic volume. While more and more companies are now used to this probabilistic approach, many others are still not. Geomodelers might face opposition in implementing the full workflow suggested in this paper. But we think it is at least worth it to have a discussion with your team about it. Hear what the resistance are about and adapt your workflow accordingly.

To simplify the wording, this paper focuses on oil reservoirs but everything described applies to gas and to oil and gas reservoirs. Also, the focus is on reservoir condition oil-in-place. Lastly, no distinction is made between reserves and resources.

VOLUMETIC EQUATION

At first approximation, computing volumes mean solving the following equation:

HCPV = BRV * NTG * PORO * So

HCPV is the Hydrocarbon Pore Volume in reservoir conditions. This is the volume we are after.

BRV is the Bulk Rock Volume. It represents the whole volume of the geological layer being the reservoir. The BRV is delimited by a top and a bottom horizon as well as potentially by fault laterally.

NTG is the Net-To-Gross. It is the fraction of the BRV in which oil is found. The NTG factor allows removing the fraction of the BRV which is full of water (in case a water zone exists) as well as the volumes populated with non-reservoir rocks (like shales above the water zone in a conventional clastic reservoir). Depending on the work at hand, the NTG can sometimes also exclude the portion of the reservoir rocks with too low porosity and/or too low oil saturation.

PORO is the average Porosity within the part of BRV full of oil.

So is the average oil saturation within the part of the BRV full of oil.

None of the input parameters are known for certain. The limited data we have about our reservoir only gives us an approximation of them. As a result, it is unwise to compute only a single, deterministic HCPV value. It is recommended to compute a range of volumes which reflect the range of possible values taken by each of the input parameters of the equation

Further, it is also important to note that the equation takes average porosity and So values as input. This point will be expanded upon, later in the next section.

ADDING GEOMODELING TO VOLUMETRIC WORKFLOWS

The traditional volumetric workflow doesn't involve geomodeling (Figure 1).

Contour maps representing the top horizon, the bottom horizon as well as the faults (if any) are built from the well markers and the seismic interpretation. These maps allow evaluating the bulk rock volume (BRV). The other input parameters are first evaluated on a per well basis, knowing the porosity and So logs as well as the facies description and the elevation of the oil-water contact, if any. NTG is the first parameter being evaluated. Different practitioners follow different approaches; however, we will focus on one hereafter.

In our example, the pay zone is defined as all the sand above the oil-water contact and the net-to-gross is defined as the ratio between the thickness of the pay zone and the total thickness of the geological unit. The average porosity and So values for this well are then computed by arithmetic average from the log values within the pay zone.

At that point, uncertainties are taken into account. Most often, a single set of contour maps exist and only a single BRV can be computed. This is the base-case BRV to which a range of uncertainty is added (for example, +/-5% around the base-case value).

In the meantime, a distribution of average porosity values for the equation is defined from the average porosity values computed

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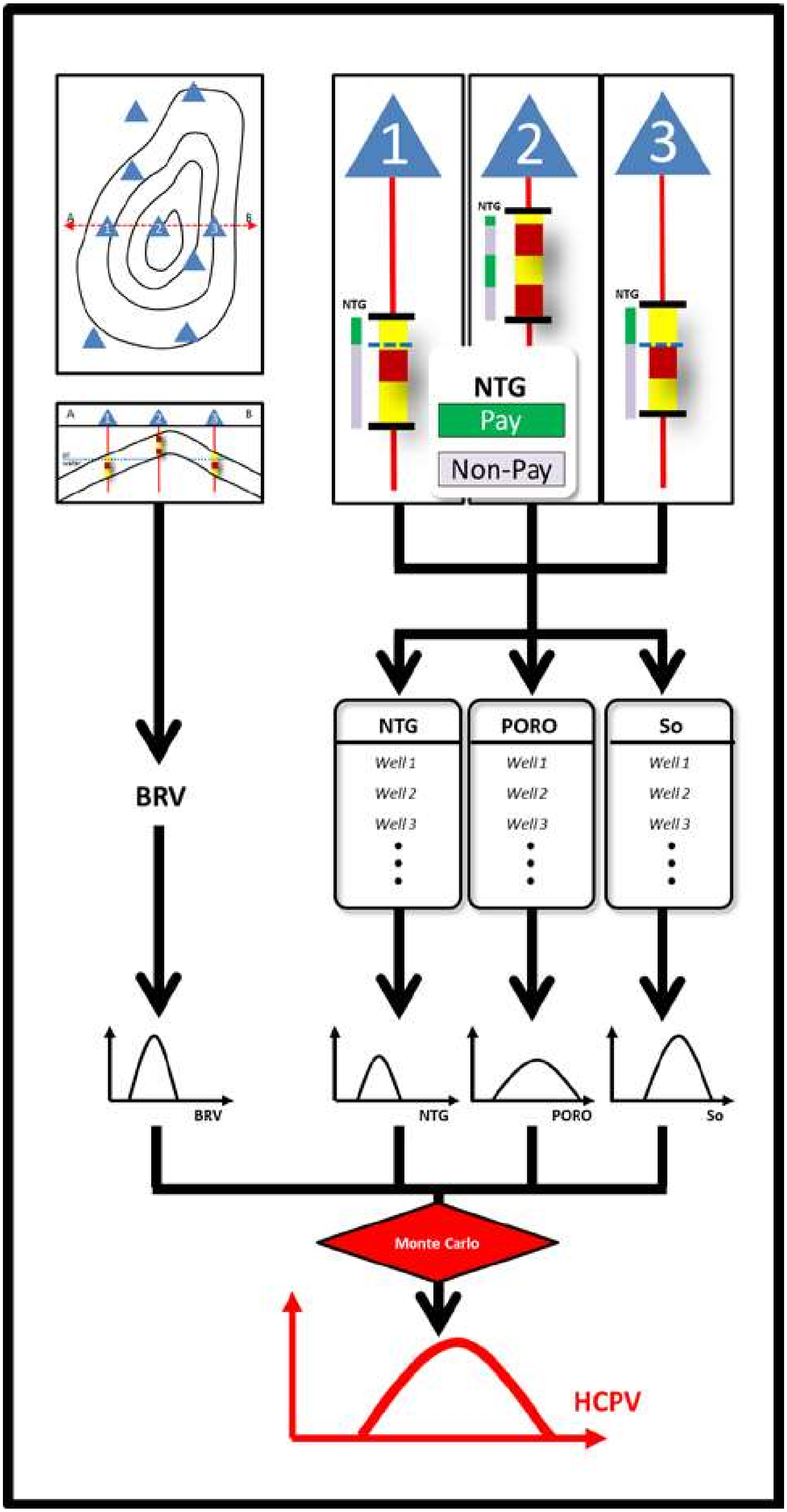

Figure 1. Traditional volumetric workflow.

at all of the wells. The same is done for the average So and for the net-to-gross.

Lastly, Monte-Carlo sampling techniques are used to run the volumetric equations thousands of times; each run using a set of values BRV, NTG, PORO and So extracted from the respective distributions. The result is a distribution of volumes which give us the range of possible HCPV values based on the input uncertainties.

The use of geomodeling changes the volumetric workflows, even if the general philosophy remains the same (Figure 2).

All the data and the geological knowledge we have are now integrated into a geomodel. At this point uncertainty is not taken into account as a range of values for the BRV, the NTG, the average porosity and the average So. Instead, multiple possible distributions of the facies and the porosity and So logs are built using geostatistical techniques. Then the volume for each realization is computed and together they make the distribution of possible HCPV.

Computing the volume for each realization means computing the volume of oil inside each cell of the 3D grid and then summing up these incremental volumes to get the HCPV volume for the whole 3D grid for the whole reservoir. This illustrates the fundamental difference between the traditional volumetric workflow and the more modern workflow based on geomodeling.

In all cases, the input data are the same: well logs, geophysical data and our overall understanding of the reservoir. On one hand, in the traditional approach, the detailed variation of the logs along the wells is quickly embedded (hidden) inside average values for each well. On other hand, with geomodeling, the detailed well data are used to build a detailed representation of the complex, heterogeneous 3D characteristics of the reservoir.

In a complex reservoir, the traditional approach might have difficulties to properly assess the impact of the 3D heterogeneity of the reservoir on the volume computations. In such cases, building a geomodel is the safest way to go. In simple, homogeneous reservoirs the two approaches will give a similar range of volumes. But considering that building a geomodel for a homogeneous reservoir is a simple, fast task nowadays, it might as well be safer to simply build one for a homogeneous reservoir too instead of relying on the traditional approach.

SHALL WE MODEL THE NET-TO-GROSS?

To some extent, in the general volumetric equation, the net-to-gross is mathematical trick used to ignore the portion of the bulk rock volume which is not in the pay zone; either because it is in the water zone or because it is made of non-reservoir facies. While porosity and So are properties we can observe or measure along the well, the net-to-gross can't. It is really an intellectual construct.

With this in mind, shall we model the net-to-gross in our geomodeling workflows with geostatistical techniques, the same way we do it for facies, porosity or So? Mathematically-speaking, we could, and sometimes indeed we should. But a lot of thought must be applied to understand what this NTG 3D property is going to represent in a given reservoir.

Net-to-gross can be expressed as a binary log along each well. For all the measured depths belonging to the pay zone, the net-to-gross log takes the values 1, otherwise 0. Computing the net-to-gross for the whole well, as defined in the traditional volumetric workflow, can then be done simply by counting the number of "1" values along the log, multiplied by the MD resolution of the net-to-gross log.

All the geostatistical techniques used to model facies can be used to model any discrete log, like the net-to-gross log. One could apply a geomodeling workflow in which the petrophysical properties would be distributed by net-to-gross values ("0" and "1") instead of doing by facies.

Is this approach recommended? Modeling net-to-gross can be necessary, on occasion, as explained in the last paragraph of this section, but with a slightly different geomodeling workflow. In most cases though, it is safer to avoid doing this.

The key issue is that the net-to-gross variable is based on several reservoir characteristics which can have independent trends. Once "hidden" within the net-to-gross quantity, it becomes impossible to model these trends properly. The problem might occur even for a simple reservoir.

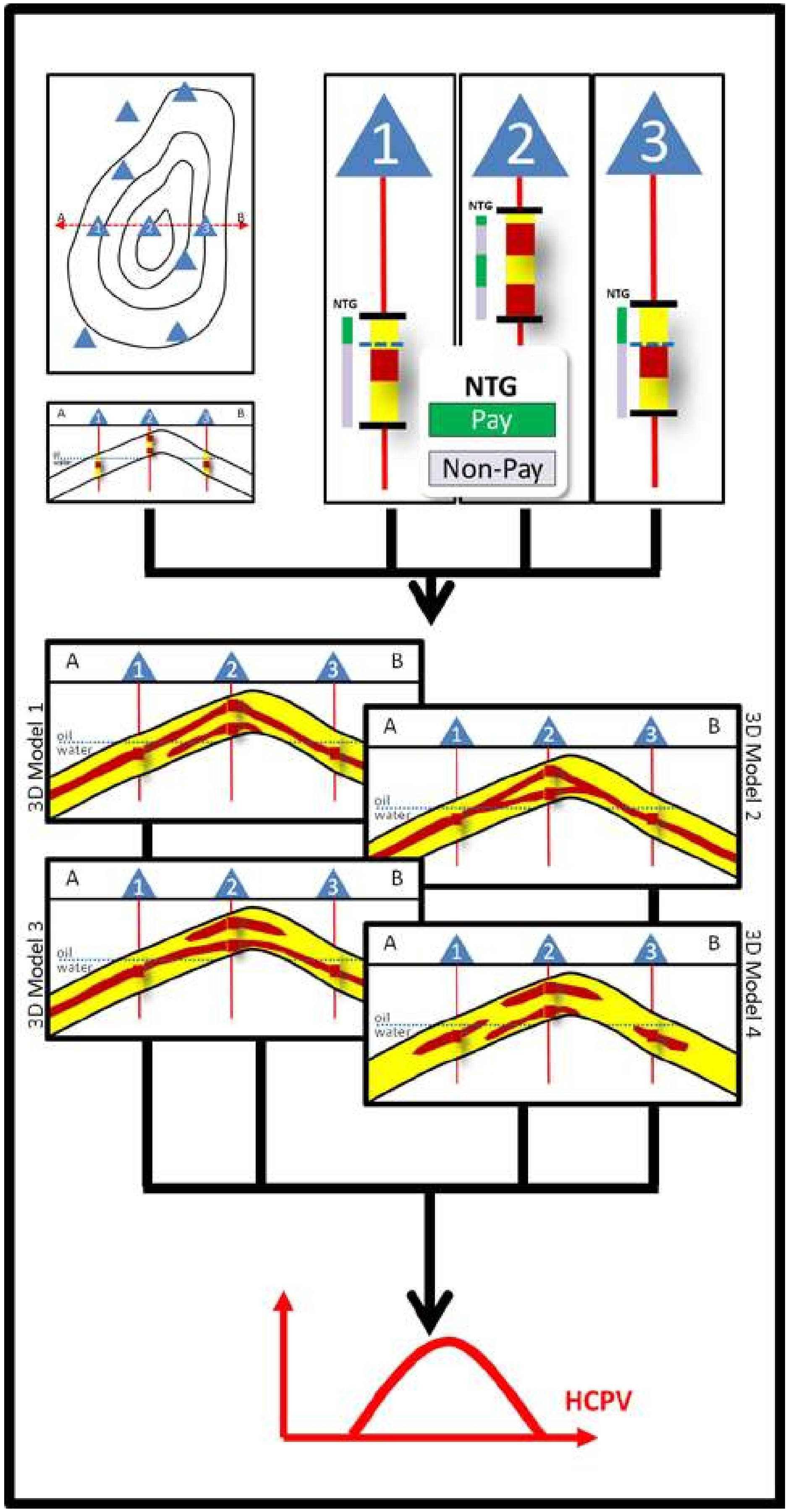

Figure 2. Modern volumetric workflow with geomodeling.

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Let's imagine a thick reservoir with no water zone (sealed faults are delimiting the reservoir) and no cut off needed on porosity nor So. Net-to-gross is only defined based on facies: sand is reservoir; shale is not.

Let's imagine that, in fact, we have two facies sand, one for sand deposited in channels and one for sand deposited in sand bars. These two sands will have different spatial distribution because they are from different depositional systems. If we model facies, we have three facies, one shale and two types of sand, and we can apply geostatistical algorithms and parameters specific to each sand. But instead of modeling facies if we are modeling the net-to-gross, then we are losing the information about two depositional systems. It would be impossible to distribute the pay net-to-gross values ("1") while respecting the geological constraints in the same way we could for the facies.

Things get even more complicated for reservoirs in which the net-to-gross is also based on porosity cut-off. The net-to-gross is now hiding possible different trends for each facies as well as specific porosity trends potentially even specific to each facies (due to vertical compaction or effects like sand grain coarsening or thinning). Add on top of this new net-to-gross cut-offs based on So or even on pay continuity (ex: ignore pay locally if it's less than X meters thick) and modeling net-to-gross with geostatistical techniques while respecting the real characteristics of the reservoir can get really, really tricky.

For that reason, it is wiser to take the time to model the facies and then the petrophysics by facies. Then, once the 3D model built, one can always apply a formula to compute locally a net-to-gross property from the different petrophysical properties. As with the wells, the net-to-gross is now derived from the rock characteristics; it doesn't guide how they should be distributed.

As mentioned earlier though, in some cases, a sort of net-to-gross property might be needed too. It can be used to capture heterogeneity which is of smaller resolution than the vertical cell size of the geomodel. In such approach, the net-to-gross won't take only values "0" and "1", but any number between 0 and 1.

For example, let's imagine a thinly laminated sand reservoir in which the succession sand/shale is at the centimeter scale. Ideally, we would need to model such a reservoir with a 3D grid of vertical sub-centimeter resolution. Mathematically, it would be impossible though: the 3D grid would have hundreds of millions of cells and computations would take forever. We are obliged instead to use a coarser resolution (let say 10cm). If we were to simply to create a facies in the 3D grid with values "sand" and "shale", we know that we would make a mistake: in fact, each so-called "sand" cell would have a certain percentage of shale in it and each so-called "shale" cell would also have a certain percentage of sand.

A continuous net-to-gross property could help capturing this though and the geomodeling could go as follow:

- No facies modeling

- Compute a continuous net-to-gross property in the cells crossed by the wells. A value of 1 would mean the cell is 100% made of sand while a value of 0 would mean it has no sand in it. Every ratio in-between is possible. Model this continuous net-to-gross property with geostatitics.

- Independently from this, model in 3D the porosity and the So using only the log values from the thin sands as input.

- Compute the volumes per cell and then sum them over the whole 3D grid (same workflow than before).

MAIN SOURCES OF VOLUME UNCERTAINTIES

We have many sources of uncertainties in our reservoirs. A wide spectrum was covered in previous papers of this series, through the angle of how we can integrate them in our geomodeling workflow. The present section is meant as a summary of all of them.

The bulk-rock volume is controlled by the geometry of the top horizon, the bottom horizon and of the faults. As such, uncertainty on these different surfaces is to be considered.

If only wells are available (no seismic), one should consider the uncertainty in the contouring far from the wells, and also the uncertainty in the picks themselves. The former is covered in the part 4 of this series (May 2015 issue of the Reservoir magazine). This is the main source of uncertainty. If contouring was done using geostatistical techniques, uncertainty in the variograms and the distributions should be considered too (part 3, April 2015 issue). The uncertainty on the picks is usually minimal, but it might still be good to check, just in case.

If a seismic interpretation is available, very likely no contouring will be applied anymore. Instead, we now have to consider the uncertainties linked to the seismic interpretations: the interpretation itself in the time domain and the effect of the time-depth conversion. The former is a geophysical issue, which goes beyond the scope of this series, while the latter is covered in the part 6 of this series (Dec 2015).

In faulted reservoirs, the geometry of the faults is a large source of uncertainty. It might even go as far as questioning the presence, or not, of some of them. In such cases, it might be interesting to build some models without the questionable fault(s) and some with.

If several fluid zones are present, the geometry of the fluid contact surfaces is also source of uncertainty. If all the contacts are only apparent (water-up-to, oil-down-to…), the depth of the contact is only partly known. Beyond this, if the reservoir is compartmented, different contacts might co-exist.

The 3D property models are also a large source of uncertainty. The one most often ignored while it is, in fact, a key factor is the internal geometry of the 3D-grid itself. Building the internal mesh, for example, parallel to the top horizon, or parallel to the base, or parallel to another surface might create some very different property models. It all relates back to uncertainty on the deposition space within each geological unit (covered in part 2, March 2015).

Beyond that, uncertainty in property modeling lies within the choices we make in term of geostatistics (part 3 again, April 2015). What algorithms are we using? What values for the input parameters? Facies proportions are a key controller of the oil volumes in the reservoir. Facies proportions are also an input parameter to many algorithms. It is important to build models based on variations of these proportions. Uncertainties in the variogram shape, size and orientations will mostly lead to uncertainty in the level of connectivity of the reservoir rocks. For the oil sands, for example, this is important as we tend to consider only the volumes of large connected geobodies (in which we can apply steam-assisted production techniques).

Facies tend to have specific petrophysical ranges of values and these ranges tend to be narrow within each facies. As such, uncertainty in the porosity or the So values tend to be less of an issue. If you have to choose, focus first on characterizing the uncertainty on the facies. But if time allows, look also at the possible uncertainty in the logs themselves (part 5, July/August 2015 issue).

All in all, uncertainties in bulk-rock volumes and in facies (proportions, orientation, but also the geological hypotheses about the depositional environment) tend to be the main ones impacting the range of volumes. However, only a review, with the whole team, will allow confirming it or pinpointing to other more important ones in your specific reservoir.

CONCLUSION

Running volumes on a geomodel is a standard thing to do, even if your team prefers to rely on more old-school traditional methods to book the reserves and resources. At the least, you must make sure that your geomodel doesn't contradict the volumes officially reported. If it does and if, after review, your geomodel doesn't seem at fault, then the whole team should take the time to find how to reconcile the different results.

The next paper will focus on production engineering.

TO GO BEYOND

Take the time to check the impact of the geometry of the mesh of your 3D grid on the modeling of the properties. It can be an important source of uncertainty in some reservoirs that is often not considered in modeling projects.

THE AUTHORS

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