# Optimal Well Placement in Presence of Multiple Geostatistical Realizations

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## Abstract

*The placement and timing of production and injection wells is a significant decision in reservoir development planning. Well placement is difficult with a single deterministic model of reservoir structure and petrophysical properties. The duration of plateau production must be maximized, water handling must be minimized, recovery should be maximized and key economic indicators should also be maximized. These response variables depend on the placement/timing of the wells, their operating conditions and the subsurface reservoir description. Many of the complex nonlinear interactions are resolved by simulating the reservoir behavior with a number of cases. A combination of sound engineering judgment and flow simulation are used in practice. The problems associated with well placement become more complex in presence of multiple geostatistical realizations. The number of flow simulation runs becomes intractable and it becomes impossible to visualize all possibilities. There is a need for numerical measures to assist in the optimization of well locations to minimize risk and maximize reservoir performance. Well placement is improved by establishing a quickly-calculated proxy for the performance of a particular well plan and reservoir description. The static proxy must be calibrated with some flow simulation results. Then, optimization of the well locations can be performed over multiple realizations simultaneously. The results can be used to supplement good judgment and flow simulation of base case realizations.*

## Introduction

An ongoing challenge in reservoir development is to quantify uncertainty in the reservoir description with a set of numerical geological models that respect the available data, geological interpretations, and the varied interests of multiple owners. There is unavoidable uncertainty in the geological model and alternative scenarios should be considered. Any scenario that cannot be discarded on the basis of credible data and expert judgment should be included with some probability. The direction of modern geostatistical reservoir modeling is to formalize a set of scenarios and construct a number of realizations from each scenario. Each realization is a full specification of the reservoir structure, rock properties and fluid properties. Establishing a set of realizations and their associated probabilities remains one of the most important areas of development in geostatistics. For the purposes of this research note, however, we assume that such a specification of uncertainty exists, that is, we have $n_L$ geostatistical reservoir models with associated probabilities: $p_l, l=1,\dots,n_L$.

Consider a well plan $\boldsymbol{W}$ defined by some number of wells, the location and orientation of the wells, and the timing of the wells. Flow simulation could be considered on each of the $n_L$

reservoir models using $\boldsymbol{W}$ to assess the uncertainty in critical response variables such as the cumulative production. Each response would be weighted by its probability, $p_i$. It is common to summarize the responses by their probability weighted average. The main problem, however, is that $n_L$ flow simulations would have to be considered for each candidate well plan.

The number of candidate well plans is essentially infinite. If there are 10000 locations, 10 wells, and 100 realizations, then there are ${}_{10000}C_{10} \cdot 100 \approx 10^{40}$ combinations, which is a lot. You wouldn't be one trillionth finished by the end of your lifetime if you could run one flow simulation every nanosecond.

The conventional approach is to consider a few *reasonable* well plans and perform some limited perturbations/optimization. This resulting solution is likely to be close to the optimal because experienced reservoir engineers can quickly rule out many bad well configurations. Nevertheless, there is still room for improving the well plan by considering an optimization scheme. The consequences of a minor improvement in the well plan are enormous; a fraction of a percent improvement in recovery translates to a large sum of money. It is impossible to run flow simulation for many well configurations and geological models. Thus, the basic idea:

1. Run some flow simulations with different well configurations and different geological models. The optimization will be better with more flow simulations; 20 different models would provide a starting point. The different models should somehow "bracket" the expected result, that is, be reasonably different from each other. The summary flow response variables are calculated from each flow simulation. Summary flow response variables are also calculated for each well individually.

2. Propose static reservoir quality measures that capture the local *goodness* of the reservoir, for example, connected pore volume discounted by attic oil and tortuosity.

3. Calculate the static measures on the models used for flow simulation in step one. Calibrate the static reservoir measures to the flow response variables using classical multivariate statistical tools. The result is a static reservoir proxy for flow simulation that can be optimized very quickly.

4. Optimize a set of well locations that maximize the calibrated measure of static reservoir goodness over all realizations accounting for their probability. This optimization can be repeated considering changes to the number of wells, and initial configuration, weighting of different factors.

5. Validate the results by performing flow simulation on the optimal configuration and reasonable alternatives proposed by the reservoir engineer *before* (and after) the optimization.

There are many limitations of this approach: (1) it is impossible to capture the effect of timing and the incremental knowledge gained during the drilling program, (2) the physics of flow are not accounted for directly in the optimization, (3) the location of injectors and the pore volume replaced by water injection are not accounted for, and (4) the specifics of well completion are not accounted for. There are many more limitations. Notwithstanding the long list of limitations, there is significant value in the optimization. Attention is focused on what makes a well plan good and important features of the reservoir are better understood.

It is simply impossible to flow simulate many different well plans on the many different geostatistical models that are available. The proposed static optimization accounts for the dynamic behavior of the reservoir through the calibration to the flow response. The optimization accounts for all geological scenarios with the correct probability. The results are checkable with flow simulation. A variety of other constraints (platform location – total distance of the wells from the platform, well orientation, etc.) can be included in the optimization objective function.

The actual optimization is based on simulated annealing (SA), which is a very powerful technique that does not require analytical sensitivity coefficients. SA is one of the *natural-process-inspired* computing techniques (along with neural networks and genetic algorithms) that have effectively solved a large class of combinatorial optimization problems.

## Flow Simulation / Summary Flow Response

This paper concerns a hypothetical reservoir example. Although the methodology has been applied on many reservoirs, no real data has been released. Eclipse™ was used to simulate the performance of different well plans on different geological models. The experimentation described in this research note centered around one geological scenario. There are alternatives that may be considered in the future. The set of 100 geostatistical realizations for the geologic scenario of interest were ranked and 11 geostatistical realizations corresponding to the $P_0$ (minimum), $P_{10}$, …, $P_{90}$, and $P_{100}$ (maximum) were chosen. Four different well configurations were considered, thus 44 full field flow simulations were performed for the first phase of calibration and optimization. The well control options within Eclipse were the same for each run. The discounted cumulative oil production (discounted by 10%) was used as a summary measure of flow response.

There are two types of production wells (1) initial producers in the mid-dip region that provide high rates in the early years, but that will see high water cut within 3-4 years of production, and (2) ultimate producers in the up-dip region that will produce the displaced oil swept from injectors at the OWC and ensure high recovery. The optimization procedure for these two well types is quite different. The optimization of the initial producers was relatively straightforward using a measure of connected volume. This initial set of 44 flow simulations proved adequate to calibrate and optimize the locations of early primary production wells.

The optimization of the ultimate producers must balance two competing objectives (1) move them as far up-dip as possible since oil farther up-dip will have poor recovery, and (2) move them down-dip to remain in good quality reservoir to maintain production rate. The calibration and optimization required extensive fine tuning to devise an optimization scheme for these updip producers. A further set of flow simulations were performed with the $P_{50}$ geologic model and nine different well plans were simulated to permit calibration and optimization of the ultimate producers in the up-dip region. The discounted cumulative oil production was the single summary variable considered in all cases.

## Static Measure of Reservoir/Well Quality *for Primary Depletion*

A key feature of the optimization approach described in this paper is the definition of a static measure that is quick and easy to calculate and that captures the combined quality of a well plan and a reservoir model. The static reservoir quality is mainly based on reservoir volumes. These volumes are discounted by distance from the well (the specific distance weighting must be calibrated, but previous studies indicate that an inverse distance squared parameter works quite well, Cruz et al 2004). The oil water contact also constrains the static reservoir quality measures.

The permeability is often considered in the calibration. A harmonic average may be calculated along the line of sight from each block to the nearest well location. This average will be used to weight the contribution of each block to the reservoir quality. Other parameters have been considered in the past including attic oil, tortuosity, distance to OWC, but these are frequently found to be of second order importance. A first approximation to the static reservoir quality:

$$Q_S = \sum_{iw=1}^{nw} \sum_{j=1}^{n_{iw}} V_j \cdot \phi_j \cdot \left(1 - S_{w,j}\right) \cdot \left(\frac{1}{d_{j,iw}}\right)^{w_d} \cdot k_{j,iw}{}^{w_k} \tag{1}$$

Where $Q_S$ is the static reservoir quality for a particular well plan and geological model, $nw$ is the number of producing wells, $V_j$ is the volume of cell $j$ that is close to well $iw$, $\phi_j$ is the porosity of cell $j$, $S_{w,j}$ is the water saturation of cell $j$, $d_{j,iw}$ is the distance of cell $j$ to well $iw$, and $k_{j,iw}$ is the harmonic average of the permeability from cell $j$ to well $iw$ in the shortest path. In this formalism, we only need to calibrate $\omega_d$ and $\omega_k$.

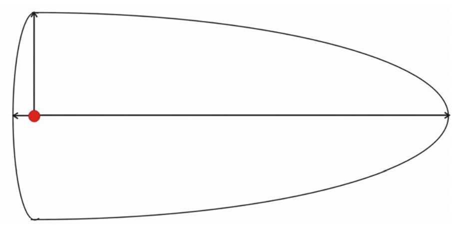
The calibration was performed with the 44 flow simulation cases described above. The $\omega_d$ and $\omega_k$ parameters were iteratively adjusted to maximize the correlation between the discounted cumulative oil production and the static reservoir quality. The distance and permeability factors were optimized to be 1.2 and 0.073. The relatively low value of the permeability factor is partially due to the units of the factors. The resulting correlation coefficient was 0.97; see Figure 1 at the end of this note. The well locations were optimized using this measure of reservoir quality; however, the improvement was only beneficial during early production. A revised measure of static quality was devised for the ultimate recovery wells.

### Static Measure of Reservoir/Well Quality *for Ultimate Recovery*

The recovery mechanism in each reservoir must be considered. In this hypothetical case, water is intended to displace the oil updip from the OWC and water injection wells. The well locations optimized using the static measure of quality described above do account for this directionality. The additional flow simulation results using different well plans and the P50 reservoir model provided some valuable insight into the importance of this displacement mechanism, the importance of the faults, and the confounding affect of the well management strategy in Eclipse.

The calibration was modified to account for (1) the poor recovery of oil updip from the final producers, and (2) the good recovery of oil between the injectors/OWC and the producers. There is a need to balance the risk of a poor quality well too far updip with the risk of unrecovered oil because the wells are too far downdip. An anisotropic weighting function is considered in the calibration.

Maps of the initial and final hydrocarbon volume were created for a number of different well plans. Recovery was very poor beyond 400m in the updip. The influence was much greater in the direction toward the OWC and somewhat reduced along strike. The isodistance lines from a producer were setup to follow a two part ellipsoid (see below). There are three distance parameters to specify the function.



The ranges of 400/2000/8000 m were arrived at after some experimentation. It would be reasonable to include these parameters in the calibration procedure. The scalar distance h from a grid cell to a well is calculated as follows with $a_{dip}$ set to 400 or 8000 depending on direction and $a_{strike}$ set to 2000.

$$h = \sqrt{\left(\frac{h_{dip}}{a_{dip}}\right)^2 + \left(\frac{h_{strike}}{a_{strike}}\right)^2}$$

Any grid cell outside of these ranges (that is, $h > 1$) does not contribute to the static proxy. Grid cells within this range are included at a weight based on a calibration parameter $f_{dis,j} = \left(1 - h_j\right)^{\omega_d}$. This can be considered a refinement of the isotropic static reservoir quality measure; there is a preferential weighting of downdip oil. The dip direction is quite important. It was taken as constant, but could be locally modified in future work.

The permeability from each cell to the producer, along a stratigraphic slice, is calculated and scaled by a maximum permeability.

$$f_{k,j} = \left(\frac{k_j}{k_{max}}\right)^{\omega_k}$$

The parameters $\omega_d$ and $\omega_a$ are optimized in the calibration program. So, the static proxy is being calculated as:

$$Q_S^l = \sum_{iw=1}^{nw} \sum_{j=1}^{n_{iw}} V_j \cdot \phi_j \cdot \left(1 - S_{w,j}\right) \cdot f_{dis,j} \cdot f_{k,j} \tag{2}$$

Two other important changes were added to the calculation of the new static reservoir quality measure: (1) geoobject connectivity, and (2) the fault locations. A geoobject defines a volume in the reservoir that is connected to itself, but disconnected from the rest of the reservoir. There are fast algorithms for calculating the geoobjects for a 3-D grid. A grid cell comes into Equation (2) only when it belongs to a geoobject that is also intersected by the well location. This is considered important as the net-to-gross decreases in the updip locations. The fault locations should come into the geoobject definition, but the geoobject routine works with regular 3-D grids; therefore, the fault locations were entered explicitly and cells were not allowed to connect to wells across the fault locations.

The calibration works quite well. The correlation was around 0.8 (and not the 0.97 shown in Figure 1); however, the calibration results all come from the same realization, which is harder to calibrate against since the OIP is fixed.

***Comments on Calibration***

A number of other parameters were considered in the calibration. The well permeability (the summed *kh* at the well location) was found to be of minor importance. A measure of tortuosity was attempted, but it was not found to be important for discounted ultimate recovery. The STOIP was also included in the calibration, but it is already included in static reservoir quality measures and it was found to be of minor importance.

## Optimization

The objective function is the total reservoir quality measure summed over all wells and cells. Each cell reports to the closest well if it is within the elliptical area of influence. The cells must be within a connected geoobject. The weighting is defined in Equation (2).

Ideally, the well optimization would simultaneously optimize the locations of the early producers in the center of the reservoir and the late ultimate-recovery producers in the updip locations. The interactions between these two types of producers would have to be worked out by flow simulation. The well optimization program, however, was only setup for only one type of wells at a time. For flexibility, the program permits some locations to be frozen. The focus was on the ultimate producers.

A full simulated annealing optimization was not implemented; all favorable changes are accepted and all unfavorable changes are rejected. The initial well configuration is specified by the user (the field development plan in this case). The wells are randomly considered for a change. The allowable changes are a unit grid cell movement in any direction. Wells are not added or taken away; different numbers of wells must be optimized separately.

Figure 2 shows an example of some optimized well locations. The red dots at the right are the injector locations, the black dots are the producer locations, and the yellow filled circles are the optimized locations. The middip early producer locations were frozen. In general, we see that the producers were moved slightly updip and spaced out a little more uniformly. The optimization takes a few minutes of CPU time and converges in about 500 iterations. The improvement in the total accumulated reservoir quality is reported to be 3.85%. Flow simulation was performed with the optimized well locations and an improvement of about half this amount was found. This modest percentage improvement could have a large economic consequence. The important feature of this approach to well location optimization is the possibility to consider multiple geologic scenarios and realizations in an objective manner. An engineer with a good understanding of the reservoir and the recovery mechanism may be able to out-perform this optimization on *one realization*. The optimization provides unquestionable value in determining a well plan that is jointly optimal over multiple realizations and competing objectives such as avoiding low reservoir quality locations whist maximizing ultimate recovery.

### Conclusions

The results of optimizing well placement in presence of multiple geostatistical realizations are promising. Prototype programs are documented in the Appendix that may prove useful to the industry sponsors of the Centre for Computational Geostatistics. They have evolved from a number of case studies.

The main advantage is the ability to optimize over a set of alternative geostatistical realizations and a repeatable quantifiable measure of goodness. The results of optimization can be tweaked to account for complex considerations not easily coded in an optimization algorithm. There will always be multiple realizations when a development plan is being established – the uncertainty will diminish as additional wells are drilled, but it will not go away. Optimizing over multiple realizations and achieving well locations that are robust over the entire space of uncertainty is desirable.

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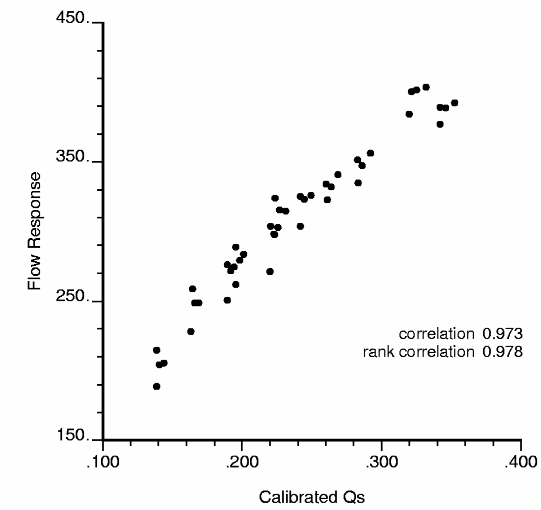


**Figure 1:** Cross plot of the dynamic flow response versus the calibrated static reservoir quality measure.

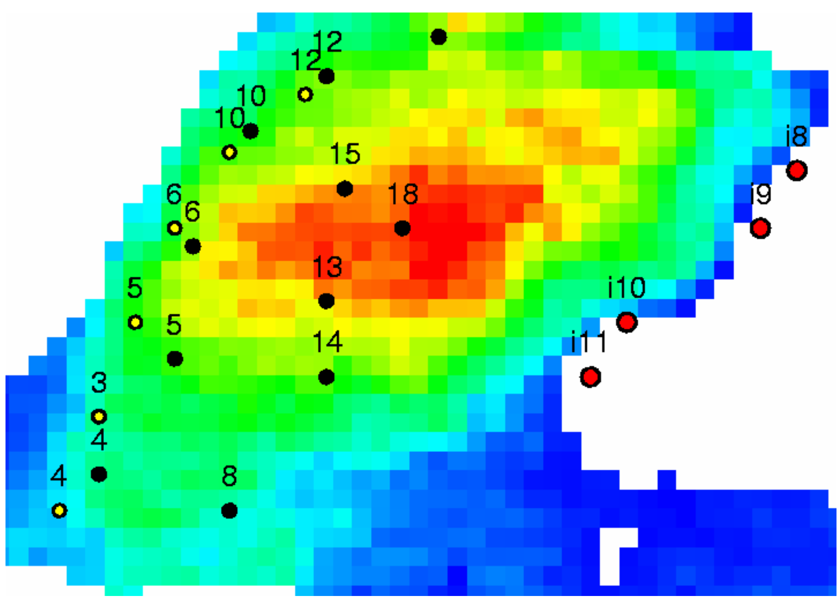


**Figure 2:** Example of optimized well locations. The red dots at the right are the injector locations, the black dots are the producer locations, and the yellow filled circles are the optimized locations.

## Appendix: Brief Program Documentation

These programs are being released to CCG members in the hope that they will be useful. Application of these programs to additional case studies will certainly help them mature and become standard practice. There is nothing particularly difficult about the code or the concepts. The three main programs will be documented below: (1) `Qs_getcells`, which prepares the input for the calibration program, (2) `Qs_calibrate`, which determines the optimal calibration parameters, and (3) `Qs_optimize`, which optimizes a set of well locations. These programs all work together, that is, the formulation of the static reservoir quality measure must be consistent between the programs.

The parameters for the `Qs_getcells` program:

```
Line   START OF PARAMETERS:
 1     PXXgeo.dat                         -file with input geometry data
 2     1  2  3    4  5  6                 -  columns for ix,iy,iz and x,y,z
 3     PXXgrid.dat                        -file with input gridded data
 4     1  2  3    5  6  7                 -  columns for vol, por, ntg, perms
 5      98  129   39                      -  grid size: nx,ny,nz
 6     Wells-YY.dat                       -file with input well locations
 7     1  2                               -  columns for x/y cell indices
 8     -9175.3                            -elevation of OWC
 9     -1.0 0.1 -1.0 -1.0                 -cutoffs for NTG, poro, perm, hvol
10     -5.                                -rotation angle of X to water
11     400.0  2000.0 8000.0               -radius for connected
12     FaultLocations.dat                 -file with fault segments
13     1 2 3 4                            -  columns: ixfi,iyfi,ixff,iyff
14     500.                               -reservoir quality to save in file
15     PXXYY.dat                          -file for output (for Qs-calibrate)
16     0                                  -write out full grid (0=no, 1=yes)
17     PXXYY-fullgrid.dat                 -  file for output
18     1                                  -write out well summary (0=no, 1=yes)
19     QS-YY.dat                          -  file for output
```

The geostatistical models are input in two files (lines 1 through 4). The geometry of the grid cells is specified in one file and the properties are specified in another. All input and output files are in a standard GSLIB format. The grid size is specified on line 5. The file with well locations is specified on Lines 6 and 7. The elevation of the OWC is used to clip cells from the calculation. A grid cell is considered entirely above the OWC or entirely below based on its Z coordinate specified in the geometry file. Cutoffs for NTG, porosity, permeability and hydrocarbon volume are specified on line 9 and are used for the geoobject calculation. The rotation angle (line 10) is used to orient the two-part ellipse described in the text. The radii for the two-part ellipse are specified on line 11. A GSLIB format file with start and end points of linear (vertical) fault segments is specified in lines 12 and 13. The reservoir quality number (discounted cumulative oil production) specified on line 14 is passed into the output file and is used in calibration. It is important to enter the correct reservoir quality that corresponds to the well locations and geologic model. The output file is specified in line 15. Some additional debugging output can be written using the options in lines 16 through 19.

The results of the `Qs_getcells` program are used by the calibration program (next) to determine the optimal exponents to use for the static reservoir quality measure in optimization. The results of the `Qs_getcells` program are not used by the optimization program. The parameters for the `Qs_calibrate` program:

```
Line   START OF PARAMETERS:
 1     10                             -number of flow cases to calibrate with
 2     ../Data/P50runa.dat
       . . .
12     ../Data/P50runj.dat
13     Qs-calibrate.out               -file for output
14     Qs-calibrate.dbg               -file for debugging output
15     0.0  3.0   0.5                 -wdistance: minimum, maximum, initial
16     0.0  3.0   0.5                 -wperm:     minimum, maximum, initial
17     0.0  3.0   0.0                 -wellperm:  minimum, maximum, initial
18     2000.0  15000.0                -maximums:  distance, perm
19     500                            -maximum number of iterations
20     69069                          -random number seed
```

Any number of flow cases can be considered (line 1); each is a run of the previous `Qs_getcells` program. The correct number of output files must be specified (lines 2 through 12 in this example). The calibration output is written to the screen when the program is executed, but it is also saved in two output files (lines 13 and 14). Three parameters are in this implementation: a distance exponent, a permeability exponent, and an exponent that applies to the total kh at the well location. A minimum, maximum, and initial value is specified for each parameter (lines 15 through 17). The maximum distance is not used (line 18). The maximum permeability (line 18) is used to scale the permeability values (see Equation (2) in the text). The initial values are perturbed randomly to maximize the correlation between the static reservoir quality measure and the dynamic response. The maximum number of perturbations and the random number seed are specified in lines 19 and 20.

The results of the `Qs_calibrate` is a set of parameters that can be used in the optimization program. These are entered directly in the program parameters (see below); there are no other data files that get passed to optimization. The parameters for the `Qs_optimize` program:

```
Line   START OF PARAMETERS:
 1     FDPwells.dat                   -file with initial well locations
 2     1  2                           -  columns for x/y cell indices
 3     11                             -  number of wells locations to freeze
 4     8 14 13 15 18 20 17 7 16 22 27 -  well indices to freeze
 5     Injectors.dat                  -file with injector locations (optional)
 6     1  2                           -  columns for x/y cell indices
 7       750.0                        -  minimum distance to injectors
 8      98  129   39                  -grid size: nx,ny,nz
 9     -9175.3                        -elevation of OWC
10     10000.0                        -maximum distance from wells
11       500.0                        -minimum distance between wells
12     -10  0   -7  7                 -maximum change (X/Y cells)
13     -1.0 0.1 -1.0 -1.0             -cutoffs for NTG, poro, perm, hvol
14     0.50                           -exponent for distance
15     0.75   15000.0                 -exponent for permeability, max perm
16     0.0                            -rotation angle of X to water
17     400.0  1000.0 8000.0           -radius for connected
18     FaultLocations.dat             -file with fault segments
19     1 2 3 4                        -  columns: ixfi,iyfi,ixff,iyff
20     1000                           -maximum number of iterations
21     Qs-optimize.out                -file for output (for updated well locations)
22     1                              -number of reservoir models to consider
23     1.0                            -  probability for this model
24     ../Data/P50geo.dat             -  file with input geometry data
25     1  2  3    4  5  6             -    columns for ix,iy,iz and x,y,z
26     ../Data/P50grid.dat            -  file with input gridded data
27     1  2  3    5  6  7             -    columns for vol, por, ntg, perms
```

The `Qs_optimize` program operates by iteratively changing a set of input well locations. The input well locations are specified in lines 1 and 2. Some number of the wells can be frozen (lines 3 and 4). It is possible to specify a file with injector well locations and to ensure that the optimization program does not move the producer wells too close to the injectors (lines 5, 6 and 7). The grid size and elevation of the OWC are specified in lines 8 and 9. The maximum distance of grid cells from the wells is specified in line 10; however, this is overruled by the radii specified in line 17. The minimum distance between wells is specified in line 11. The parameters in line 12 specify the window within which an input well can be moved. This can be used to keep the wells from being relocated too far from their original locations. The calibrated exponents for distance and permeability are specified in lines 14 and 15. The rotation angle for the contact is specified in line 16. The radii for the two-part ellipse for weighting are specified in line 17. This could be set to isotropic if optimizing wells for primary depletion. The faults are specified in lines 18 and 19. The maximum number of perturbations for optimization is specified in line 20. The file for output is specified in line 21. The wells can be optimized over any number of input geological/geostatistical realizations (line 22). Five lines of input parameters are required for each input geostatistical realization: the probability for the model (coming from the probability of the geologic scenario and the number of realizations being considered), the geometry of the model and the gridded property values.

The program is not particularly fast because all cells are reallocated to the wells and all faults are checked with each perturbation. The CPU speed of the program could be significantly improved with little effort.