Enhancements to Drainage Area Optimization for Steam Assisted Gravity Drainage

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This paper discusses enhancements made to the drainage area layout optimization software developed at the CCG. Enhancements primarily involve increasing the complexity of the geometry involved and reworking the objective function to provide a measure of the economic value of a SAGD project. Two optimization methods are developed: one for optimizing the layout of drainage areas and surface pads with more geometric flexibility and a second for optimizing the trajectories of horizontal wells. Both procedures maximize the effective recovery of bitumen.

1. Introduction

Steam assisted gravity drainage (SAGD) is an enhanced oil recovery technique that is being used to recover bitumen in several areas including the Athabasca region of Alberta, Canada. Implementing SAGD involves designing three primary components: 1 – the geometry of the drainage area (DA); 2 – placement of a surface pad (SP) or surface pads, and; 3 – horizontal well trajectories. Defining the spatial configuration of all components that should be used to recover bitumen from a specific lease or high quality reservoir is a complex optimization problem. The objective is to maximize the economic potential of the field.

Some past work on the subject has been done at the CCG including Deutsch (2008), Kumar and Deutsch (2010a and 2010b), and work continues on the subject in this year's report, including this work as well as papers 201 and 202 by Kumar and Deutsch (2011a and 2011b). Various aspects of the problem have changed over time including the geometry of the problem and the form of the objective function. Drainage areas were initially fairly rigid geometric objects with a rectangular shape and a fixed number of well pairs. Surface pads were located at one end, the heel, and were at a centered with the DA and at a fixed distance from the producing region of the DA (Figure 1). Some flexibility was later added to the location of SP's relative to the DA's using circular shaped pads, which allowed the position of SP's to be optimized when surface culture such as existing infrastructure or bodies of water were obstructing development.

In the work by Abhay and Deutsch (2010b), an exhaustive search method was used to optimize the spatial position of DA's and SP's for a whole field that maximized an objective function. The objective was a function of recovery and included penalty functions for thief zones and roughness of the base surface along which wells are positioned. Although the program indeed finds a maximum of the objective, it is not entirely intuitive due to the penalty functions (it was not a direct measure of potential bitumen recovery), and it cannot be proven that the optimized DA/SP layout results in maximum recovery. However, the solution is likely a good local maximum. To improve the intuitiveness of the objective, an enhancement discussed in this paper is an objective function expressed in barrels of bitumen and does not involve any secondary penalty factors or functions. Adding a penalty to account for base roughness for example is unnecessary because this is controlled by the geometry of the problem.

Use of rectangular DA's has several advantages including: ease of specification and optimization; all wells are the same length simplifying the drilling of wells and installation of surface equipment; performance prediction using flow simulation is usually applied to box shaped models that represent the DA. However, rectangular DA's are quite restrictive when contours of high quality reservoir follow non-linear patterns, or when DA's are limited by lease boundaries. In this case, some flexibility in the shape of DA's can be used even if the complexity of the previously mentioned advantages is increased. Enhanced flexibility of DA's is introduced in this work.

The last enhancement discussed in this paper is the optimization of well trajectories. In previous work, wells were horizontal and positioned at the lowest possible elevation so that the full well length was effective. This is not necessarily the optimal position of a well to maximize recovery. In this work, two optimization procedures are involved: a basic optimization that also uses horizontal wells, but the position that maximizes recovery is optimized; an advanced optimization procedure that permits deviated wells to improve base conformance. Both procedures find the optimal position for a single realization or deterministic model, or over a set of multiple realizations of the pertinent variables.

2. Background

DA geometry defines the area, usually rectangular, that will house a set of generally horizontal well pairs. Wells are drilled from the SP located near the heel of the DA (Figure 2). The optimization problem is to determine these three components for a field to be produced such that recovery or economic potential is maximized. Optimization is done for a set of DA's that cover a field rather than sequentially on individual DA's, since the latter would not guarantee maximum recovery across the field. This issue was discussed by Kumar and Deutsch (2010a).

The optimization problem is complex due to its combinatorial nature and is in the class of nondeterministic polynomial time (NP-hard) optimization problems. Finding the optimal position of a single DA within an area is challenging because the optimal trajectory of wells is a function of the position and orientation of the DA. The problem is also highly multi-modal (many local maxima) due to the variation in the base, top and net continuous bitumen surfaces and due to the spatial constraints from surface culture such as existing infrastructure, lease boundaries, and bodies of water among others. Devising an optimization approach that finds the global maximum of the objective function is non-trivial, which led to the exhaustive search approach used by Kumar and Deutsch (2010b). Such an approach is applicable with fixed DA geometry and fixed well lengths; however, with increased flexibility of these parameters, exhaustive search is no longer possible.

A summary of the optimization objective and variables involved is as follows, where variables are defined by surfaces and may be deterministic (a single realization) or they may be defined stochastically by several realizations. Geological variables include a base (base continuous bitumen or bcb), gross continuous bitumen, gcb, and net continuous bitumen, ncb. The top is equal to $bcb + gcb$. All variables are expressed as elevation or thickness in meters or feet depending on the application. Units of meters are used in this paper. Geometric variables include the well elevation, z, and DA geometry, V. Because an area is potentially covered by several DA's, the set of DA's is defined by S, with $V_k \in S, k = 1, \dots, N$, where N is the number of DA's involved. Each DA contains a set of wells, $W_{kj}, j = 1, \dots, M_k$, where M_k is the number of wells in DA k. Each well recovers a volume of the bitumen, R_{kj}, within a DA and is a function defined by Equation 1, where x, y, z define the three dimensional trajectory of the well and bcb, gcb, ncb are defined within a producible area of influence of the well (Figure 3). This is explained further in the Methodology section.

$$R_{kj} = f\left(bcb, gcb, ncb, x, y, z\right) \quad (1)$$

The potential recovery of the whole set of DA's is then defined by Equation 2, where C is some cost (supply costs, etc.) that is a function of various parameters of the set, S.

$$O(S) = \sum_{k=1}^{N} \sum_{j=1}^{M_k} R_{kj} - C(S) \quad (2)$$

Evaluating the objective is relatively straightforward, with the complexity involved in obtaining the well trajectory that maximizes each R_{kj} involved. The optimization problem is defined by Equation 3, where all parameters encompassed in S, including $V_k, k = 1, \dots, N, (W, x, y, z)_{kj}, j = 1, \dots, M_k$, can be manipulated by the optimization algorithm and Ω defines the feasible region of parameters.

$$\max_{S \in \Omega} \left\{ O(S) \right\} \quad (3)$$

In prior optimization algorithms, the costs were not involved; however, the penalty function used to penalize base roughness and thief zones were similar since they detracted from the overall recovery potential. One of the enhancements discussed in this work is a reformulated objective function that does not require arbitrary penalty functions and can incorporate actual costs of SAGD.

3. Objective Function

Evaluating the economic potential of a SAGD operation is accomplished using a function expressed in units of barrels of bitumen. To avoid the use of penalties, more geometric information had to be incorporated into the calculation of recovery from each well pair. In this way, properties such as base roughness and steam chamber geometry are accounted for directly in the predicted volume of recovery and optimization should arrive at a DA configuration that maximizes the actual expected recovery. Components of recovery that were accounted for in the enhanced objective function include the following:

1. Fractional recovery of ncb above the well trajectory is accounted for only when the well is effective. Portions of a well that are below the bcb incur losses in recovery.
2. The vertical offset between the injector and producer are accounted for. It is possible that a particular configuration leads to an injector intersecting the top surface, which results in recovery losses.
3. Recovery, especially early on in production, tends to behave like the thinnest portion of a steam chamber. To account for this, the total potential recovery from a well pair is related to the distribution of ncb above the well trajectory.
4. Supply costs as a function of total bitumen in place within a DA are included in the objective. The units are in barrels per barrel of bitumen so that the objective function units are unchanged. Some examples of costs that can be encompassed by supply cost are capital costs, natural gas costs for steam production, operating costs, taxes, and royalties.

Figure 4 shows a cross section along a well and indicates the fraction recovered and lost due to points 1 and 2. For the case where losses due to a producer being below the base or ineffective, the loss is assumed to be the total ncb above the well for the interval below the base; however, this may be too aggressive since over time, the steam flood should heat the bitumen leading to perhaps a cone shaped drainage pattern (Figure 5). The profile of the cone would depend on the duration of the steam flood process and is a point of future development. Evaluating the loss according to Figure 4, case B, would coincide with losses early on in production.

For point 3, a distribution of the ncb above a well trajectory is computed for each well in a DA, and then a user defined quantile is used to compute the producible thickness above each well pair (Figure 6). Based on the figure, a quantile of 0.3 would limit the producible thickness to roughly 7.5 meters, even in areas where the thickness is 15 meters. Smaller quantiles can be used to assess production early on, whereas larger values can be used for long term production.

A penalty for base roughness is not required because this is handled implicitly by unrecoverable regions below a well that is above the base and above a well that is below the base. Optimization will naturally find locations and orientations of DA's so that these loss modes (A and B in Figure 4) are minimized. A trivial example to consider is a base surface defined by a sine wave in x and a horizontal plane in y (Figure 7). Unless wells are oriented with the y axis, unrecoverable bitumen could be substantial.

4. Drainage Area Geometry

Geometry of DA's was enhanced to allow more flexibility than rectangles so that high quality non-linear features and resource boundaries can be accounted for. DA's are defined by four corners as in previous versions, but they are only constrained to have parallel sides (along the wells) so that the wells remain parallel. The toe and heel have more freedom for orientation, and wells are permitted to vary in length within some allowable limits. This results in a more complex optimization problem. Considering all DA's in a set, the following set of geometric transformation to consider during optimization were formulated (Figure 8):

1. Global rotation: the set of DA's are rotated as one object by an angle, θ.
2. Global translation: the set of DA's are translated as one object by a vector, $\mathbf{d} = (dx, dy)$.
3. Local rotation: DA's that are connected by their sides (called columns in this work) are rotated by an angle, θ.
4. Local translation: a column of DA's is translated by a vector, $\mathbf{d}$. The magnitude and direction of the vector are constrained by the orientation of the heel and toe edges of all DA's in the column.
5. Heel/toe rotation: the connecting edges between two columns of DA's are rotated by the same amount. Connections between columns are called tie-lines in this work.

Any combination of these transformations maintains parallel wells in the DA's. Global and local rotations are useful for searching for the orientation of drainage areas that have better base conformance and hence higher recovery. Local rotation combined with tie-line rotation is useful when high quality zones are not aligned in the same orientation across a field, but tend to vary and appear non-linear. Global and local translation is used to obtain better conformance to boundaries and to move SP's away from surface obstructions if that is the case. The magnitude of each transformation is constrained by the allowable variation in the length of wells, and the minimum number of wells that is required to have a DA. To ensure that wells to not become too short or long, a cost function is associated with the varying well length. It is defined by a user defined piecewise linear function with a cost at the minimum allowable length, cost for the target length is assumed zero, and a cost at the maximum allowable length (Figure 9). An example of when such costs might be incurred is if surface facilities need to be changed to account for the different length wells in a DA.

Another enhancement is the number of well pairs is permitted to vary within some minimum and maximum number of wells for a DA. The purpose of this is to improve the conformance of a set of DA's to a recoverable region or boundaries. Another enhancement to work in conjunction with variable number of well pairs is variable size SP's. SP's in the version by Kumar and Deutsch (2011b) are circular; whereas the version developed in this work uses rectangular shaped SP's that vary in size depending on the number of well pairs in the associated DA. Users define the SP size for the minimum number of wells and incremental changes in size for each well pair added to a DA. Increments can be specified as zero indicating the size of the SP is independent of the number of wells also. An example of a configuration showing all of the geometric features discussed in this section is provided in Figure 10.

5. Well Trajectory Optimization

More advanced well trajectory geometry and optimization were added as well as a more accurate computation of recovery from a well pair. Two methods are used: 1 – a basic optimization that maintains horizontal wells; 2 – an advanced optimization that permits curvilinear trajectories. Both versions are setup to maximize potential recovery from the well pair. The basic version is utilized for optimization of the configuration of a set of DA's because it is much faster and is more likely to lead to a configuration with better base conformance, that is, DA optimization is more likely to find orientations with higher effective well length. The optimization procedure uses the same objective function as the advanced method. The problem is formulated as a minimization problem that minimizes the potential recovery loss. The objective function (loss) is defined by Equation 4, where $z(x)$ is the well elevation at a coordinate x defined along the well length.

$$f(z(x)) = \begin{cases} \left(\dfrac{z(x) - bcb(x)}{gcb(x)}\right) ncb(x) & bcb \le z \le gcb \\ ncb(x) & z \le bcb \end{cases} \qquad 4$$

To compute the total loss along an entire well, the function must be integrated along the well from its origin at x_0 to its extent at x_1, Equation 5, where $\mathbf{c}$ is a vector of parameters that define the well trajectory.

$$g(\mathbf{c}) = \int_{x_0}^{x_1} f\left(z(x)\right) dx \qquad 5$$

For advanced well trajectory optimization, wells are represented using Hermite splines defined by Equation 6, where $\mathbf{M}$ is the spline coefficient matrix defined by Equation 7, z_0 and z_1 are the well elevations at points x_0 and x_1 respectively, and z_0' and z_1' are the slopes of the well at points x_0 and x_1 respectively.

$$\begin{aligned} z(x) &= \mathbf{uMc} \\ &= \begin{bmatrix} x^3 & x^2 & x & 1 \end{bmatrix} \mathbf{M} \begin{bmatrix} z_0 & z_1 & z_0' & z_1' \end{bmatrix}^T \end{aligned} \qquad 6$$

$$\mathbf{M} = \begin{bmatrix} 2 & -2 & 1 & 1 \\ -3 & 3 & -2 & -1 \\ 0 & 0 & 1 & 0 \\ 1 & 0 & 0 & 0 \end{bmatrix} \quad 7$$

To maintain horizontal wells for basic optimization, $z_0 = z_1$ and $z_0' = z_1' = 0$. bcb, gcb, and ncb are input to the program as gridded surfaces, which makes evaluating the integral complicated. The problem is simplified by resampling the gridded values to points along the trajectory and expressing the surfaces as piecewise lines. Integration is done by parts for each continuous interval along the surfaces. Intervals are specified by grid nodes and by intersection points of the well with the base if they exist (Figure 11).

The integral can be expressed analytically and it is twice-differentiable permitting optimization methods such as Newton method to be used. Equations are extensive and are omitted for this publication. Several constraints are involved in well trajectory design so the guarded Newton method is used with logarithmic barriers for the constraints. Constraints that have been implemented include: the maximum allowable slope in degrees that is applied to the endpoints and a maximum vertical deviation that is measured from the highest point along the trajectory to the lowest point (Figure 12). Constraints that are planned for implementation include: a maximum vertical offset between a producer and a neighboring injector to prevent steam bypass (Figure 13), and; to constrain trajectories to have a convex up or down shape in the event that having an undulating well results in poorer production performance (the well in Figure 12 is an example of a convex-up trajectory).

Evaluating the integral in Equation 5 is possible over a single realization or deterministic model or over multiple realizations. In the multiple realization case, the loss is summed over all realizations, Equation 8, where L is the number of realizations. By minimizing the total loss over all realizations, the expected loss is minimized.

$$g(\mathbf{c}) = \sum_{l=1}^{L} \int_{x_0}^{x_1} f\left(z(x)\right) dx \quad 8$$

Logarithmic barriers are incorporated into the objective function by creating variables that measure the deviation from a parameter to its constraint. For the slope constraints, define a variable $\theta_0 = |z_0'| - |\theta_c|$ for the slope at x_0 and $\theta_1 = |z_1'| - |\theta_c|$ for the slope at x_1. The log-barrier is defined by Equation 9, where t is a parameter that controls the accuracy of the log representation of the barrier to the actual constraint (Figure 14).

$$h\left(\theta_0, \theta_1\right) = -\frac{1}{t}\log\left(-\theta_0\right) - \frac{1}{t}\log\left(-\theta_1\right) \quad 9$$

During optimization, the value of t starts at 1 and is increased up to a very large number, 1×10^8. For each different value of t, the objective is minimized. As t is increased, the parameter set that defines the well trajectory approaches the optimal set. Incorporating the constraints into the optimization problem this way prevents the algorithm from converging too quickly to the limit of a constraint, which could lead to a sub-optimal solution.

Once a well trajectory is optimized, the actual recovery is evaluated accounting for distribution of ncb mentioned in Section 3, and accounting for the height of the injector above the producer. An additional parameter that defines the elevation difference between the injector and producer is required. In some cases, the steam chamber thickness above the producer is less than the height between the injector and producer. In this case, the injector would intersect the top, resulting in loss mode A in Figure 4. When this occurs, recovery for that portion of the producer is assumed zero. A similar scenario can occur if the producer intersects the top surface and may occur with extremely irregular steam chambers.

Optimized well trajectories can be output to file. Information that is output includes the x, y, z coordinates along the well, the base, top and quality along the well, and a probability that the well is effective. When the optimization is applied using a deterministic model or single realization, the probability is either zero or one if the well is below or above the base. For multiple realizations, the output surfaces are expected values. A sample of the output is in Table 1. It is comma delimited and easily loaded into software such as Microsoft Excel.

An example of a drainage area with five wells showing the base surface and optimized trajectories is shown in Figure 333.

Table 1: Sample output well trajectory with additional information.

DA 2 Well 3 Trajectory						
X	Y	Z	Base	Top	NCB	P(Effective)
9124.02	5202.928	107.4122	107.409	127.415	16.158	0.6
9112.909	5202.928	107.3856	107.3481	127.3439	16.14882	0.6
9101.798	5202.928	107.3526	107.1182	127.0751	16.11413	0.6
9090.687	5202.928	107.3136	106.8883	126.8064	16.07944	0.6
9079.576	5202.928	107.2687	106.6583	126.5377	16.04476	0.7
9068.465	5202.928	107.2182	106.4284	126.2689	16.01007	0.8
9057.354	5202.928	107.1624	106.1985	126.0002	15.97538	0.9
9046.242	5202.928	107.1014	105.9314	125.6794	15.91986	0.9
9035.131	5202.928	107.0354	105.6171	125.2927	15.83795	0.9
9024.02	5202.928	106.9648	105.3029	124.906	15.75605	1
9012.909	5202.928	106.8896	104.9886	124.5193	15.67414	1
9001.798	5202.928	106.8103	104.6744	124.1326	15.59223	1
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6. Program and Parameters

The program for DA optimization is called DASPOPT. It is controlled using a text-based parameter file described in Table 2.

Table 2: DASPOPT parameters

Line	Parameter	
1	START OF PARAMETERS:	
2	1200 1000	-length and width of DA
3	200	-well spacing
4	0 1 0 0	-search direction for SP (1-yes, 0-no) for all 4 directions
5	realizations.out	-Input realization file
6	100 50 100	- nx, xmn, xsize of realizations
7	100 50 100	- ny, ymn, ysize of realizations
8	-998	- no data value (everything below is trimmed)
9	10	- number of realizations
10	1 3 0 2	- columns for NCB, BCB, TZ, and GCB
11	-1	-NCB quantile for well pair performance, [0,1] = quantile, -1 = mean
12	1000 10	-target well length and allowable change in percent
13	500 1500	-minimum and maximum allowable well length
14	300 200	-well cost (penalty) for minimum and maximum length (barrels bitumen)
15	1	-drop wells if below minimum, 1 = yes
16	1	-optimize well trajectories, 1 = yes, 0 = horizontal
17	4.	- maximum slope in degrees, -1 = off
18	5.	- maximum vertical offset, -1 = off
19	0	- maintain convexity, 1 = yes
20	5.	- injector height above producers
21	2.	- height a producer is permitted above neighboring injector, -1=off
22	1 1	- optimize over all realizations (1), if 0, specify realization no.
23	0.8	- fraction effective well length cutoff for reporting
24	3 8 5	-min, max and target number of slots per drainage area
25	150 100	-surface pad width and length for minimum slots
26	20 10	- additional width and length for additional slots
27	350	- distance between surface pad and drainage area heel
28	0.1	-supply cost in barrels/barrel bitumen
29	surfdata.out	-Input surface penalty map (output from SETPEN)
30	1	- column number for surface penalty data

31	400 12.5 25	- nx, xmn, xsize of realizations
32	400 12.5 25	- ny, ymn, ysize of realizations
33	dapave.csv	-input file with initial configuration of DA
34	0 0 1 1 0	-optimization flags: glb rot, glb trans, loc rot, loc trans, line rot
35	0 0 1	- start and end angles for global rotation and precision, degrees
36	20 1	- search swath for tie-line rotation and precision, degrees
37	daopt.csv	-output file with final configuration of DA
38	1	-configuration output option: 0 - none, 1 - gain only, 2 - all
39	daopttrack.csv	-file for tracking configurations
40	wellpath.csv	-file for optimized well trajectories
41	100	-number of points to represent output trajectories
42	1	-output detailed DA information, 1 = yes
43	dainfo.csv	-file for detailed DA information

The following are descriptions of the parameters on each line:

2. The nominal length and width of the DA's that are input to the program. DA length is parallel to the wells, while width is perpendicular. These parameters are not explicitly used, but are useful for tracking output from DAPAVE that is described in Kumar and Deutsch, 2010b.
3. Well spacing is the distance along the width of the DA's between well pairs. It must divide the width exactly. The program issues an error if this is not the case.
4. The SP search direction defines the initial side that is the heel. Based on this sample parameter file, the second edge of the input DA's will be the initial heel. Edges are related to the input DA's (Line 33): the first edge is between corners 1 and 2, second edge between corners 2 and 3, and so on.
5. This is the data file that contains a deterministic model of the required variables (base, NCB and GCB and optional Thief zones) or multiple realizations of them. The current version requires the file be GSLIB format.
6. Lines 6 and 7 define the size of grid. The origin (xmn,ymn) starts at the lower left corner and indexes along x first. GSLIB grids are cell centered as opposed to corner point (Deutsch and Journel, 1998).
8. Specifies a lower trimming limit so that all properties in the file from Line 5 below this value are ignored.
9. The program can consider multiple realizations if set greater than 1 or a single realization / deterministic case if set equal to 1.
10. Columns for each property in the data file (Line 5).
11. The NCB quantile defines how each well pair will perform based on the distribution of NCB above a production well. A quantile of 0 uses the min thickness, of 1 uses the max thickness, and specifying -1 will use the mean thickness.
12. Lines 12 to 14 define the well cost function described in section 4.
15. During optimization, if wells are found to be less than the minimum allowable length from Line 13, they can be deleted. This also relates to Line 24 and the minimum number of slots. If deleting a well leads to a number of slots less than the minimum, the DA is also deleted.
16. Lines 16 to 23 are for the basic and advanced well trajectory optimization described in Section 5. In the basic version, wells remain horizontal and constraints on Lines 17 – 19 are not used. Advanced well trajectory optimization is applied only once at the end of optimizing the DA configuration. Trajectories can be constrained or unconstrained by specifying values for the various constraints, or by turning them off.
17. Defines the maximum slope in absolute value permitted for the wells.
18. Maximum vertical offset defines the allowable difference in elevation from the highest point along a trajectory to the lowest point.
19. This constraint is currently under development and it will constrain the well to have a single convex-up or convex-down shape in cross section along the well.
20. The elevation offset from producer to injector is required to detect cases where the injector intersects the top surface if a steam chamber is too thin.

21. Neighboring well elevation constraints were discussed in Section 5. The injector height from Line 20 is used to detect when neighboring producers are above them, which may lead to steam bypass. This constraint is currently under development.
22. Well trajectories can be optimized using all realizations simultaneously (maximizes recovery in expected value) or using a specific realization.
23. A cutoff value for fraction of effective well length is specified for reporting purposes. The program will calculate the probability that the fraction of effective well length is greater than the cutoff. If a single realization is used for optimization, probabilities will either be zero or one, but take on more variability if multiple realizations are used.
24. The number of slots in each DA can be varied between the minimum and maximum, while the program tries to maintain DA's with the target number of slots.
25. Lines 25 – 27 define the SP geometry described in Section 4.
28. Supply cost defines all costs associated with a DA and is equal to the total bitumen in place multiplied by the supply cost parameter. Bitumen in place is used in cases where a DA has poor production so that the objective function is very low or negative and the DA is identified as uneconomic.
29. It is possible to constrain the locations of SP's using a surface penalty map. The penalty might define areas such as lakes or existing infrastructure that prevent the development of a SP. A program called SETPEN (Kumar and Deutsch, 2010b) can be used to create the surface model, which consists of one's (SP is allowed) and zeros. Line 30 defines the column number in the file while Lines 31 and 32 define the grid in the same manner as Lines 6 and 7.
33. The input configuration of DA's can be from the DAPAVE program, or it can also be from output generated in a previous optimization run of this program (output files on Line 37 or 39), see Appendix A.
34. Flags for the types of optimization to use are set on this line. Some of the operations were described in Section 4. Global rotation rotates all DA's together; global translation optimizes the position of all DA's together in a direction parallel with the wells (or parallel to the average direction of wells if DA orientation is varying); local rotation rotates the set of DA's in each column independent of other columns; local translation translates the set of DA's in each column; and tie-line rotation rotates the tie-lines joining columns of DA's.
35. For global rotation, the start and end angles to search within are defined as well as an angle precision that defines stopping criteria. Rotations start coarse and are slowly refined to converge to an optimal. When the search window is within the precision value, optimization is stopped. Angles are measured counter clockwise from the x axis. It is possible to setup the program to rotate the DA's to a specific angle: set the rotation optimization to 1 and set the start angle equal to the end angle with a precision greater than zero. This may be useful for running a few tests on some different orientations.
36. The search swath for tie-line rotation defines the ±angle range that is searched. The limit of tie-line rotation is defined by the minimum and maximum well length on Line 13 and is determined by the program. Too large a rotation is detected by the program and the rotation is not applied. Tie-line optimization will still execute; however, it may take longer than if a smaller search was defined. Precision works identical to that for global rotation in Line 35.
37. An output file of the final DA configuration with the same format as the input file on Line 33. This can later be used as input for another optimization run.
38. The configuration output option is for tracking configurations as optimization takes place. Specifying zero will output nothing; 1 will output configurations every time a higher objective is reached; and 2 will output every step taken. The format is identical to the input file on Line 33, so it is possible to extract any of the tracked configurations and save it as a new input file for another optimization run.
39. The file for tracking output. If the tracking option in Line 38 is zero, this file is not created.

40. Well trajectories as described in Section 5 are output to this file. If trajectory optimization on Line 16 is set to zero, output trajectories are horizontal.
41. This is the resolution of the trajectories, that is, the number of points that will be used to represent it. In this case, there will be 100 points along the length of all wells.
42. Set this flag to generate a detailed summary file.
43. The file for detailed output.

7. Example

A channel-like zone of high quality reservoir is used for an example. There is surface culture in the form of a river and a small lake. An arbitrary lease boundary is used as an area of interest (Figure 16). The CLIPDATA, DAPAVE and SETPEN programs from Kumar and Deutsch (2010b) were used to prepare the data for DASPOPT. In this example, DA's are 2000 m by 1400 m in size with a well spacing of 200 m. The target well length was 2000 m ± 10% and minimum and maximum allowable well lengths were 1000 m and 2500 m respectively.

The initial DA configuration is shown in Figure 17 and it has a value of 1,794.65 million barrels of bitumen with horizontal wells and 1,911.36 million using trajectory optimization. Optimization using global rotation alone does not improve the result due to the varying trend of the channel and due to the surface obstruction. Using global rotation with a start and end angle of 0 and 90 degrees and optimizing trajectories resulted in a value of 1,906.61, which is approximately no change. Optimization took 26 seconds. The configuration is shown in Figure 18 that shows some loss due to edge conformance and the lake and river has made it infeasible to create SP's for two DA's that are in the best portion of channel. To achieve better conformance around surface obstructions, global translation was coupled with the global rotation (Figure 19) and results in a value of 1,980.97. No DA's are made infeasible due to the river in this case. Optimization took 189 seconds, or just over 3 minutes. A similar result is obtained using column translation coupled with global rotation (Figure 20). Optimization in this case took 84 seconds and resulted in a value of 1,977.67.

For this example, it is clear that column rotation is required to conform the DA's with the base of the channel. Coupling column rotation, column translation, and global rotation optimization results in a value of 2,005.99 and the configuration of Figure 21. Execution time was 236 seconds or roughly 4 minutes. More of the high quality zone beneath the lake is also covered by drainage areas. During the optimization, some iterations were encountered with higher values. To converge to these, the precision of global rotation was sharpened from 1 degree to 0.1 degrees. Optimization took 315 seconds or 5.25 minutes and resulted in a value of 2,009.33. The configuration is not shown since differences with Figure 21 are subtle.

8. Conclusions and Future Work

Numerical optimization can be utilized to automatically design the layout of drainage areas and surface pads for SAGD applications as well as determine the optimal trajectories of wells within each drainage area. Optimization is done to maximize the economic potential or recovery from a set of drainage areas for deterministic models or multiple realizations. Two components developed in this work were optimization of the layout of drainage areas and optimization of the well trajectories. Considering the complexity of the drainage area and well trajectory problems, optimization runs in a reasonable amount of computing time.

There are several areas that will benefit from further research and development in this area. Not a significant amount of effort was spent on optimizing the position of surface pads; however, this will aid in developing areas where surface constraints are prohibitive. Complexity can be added to a few areas including: drainage area geometry could be relaxed to permit non-parallel wells; methods to optimize around existing drainage areas and surface pads could be developed; more accurate calculation of recovery and costs could be incorporated to account for important properties like the steam-oil ratio. More constraints can be added to the well trajectories including those suggested in the text: a maximum vertical offset between a producer and a neighboring injector to prevent steam bypass, and; to constrain trajectories to have a convex up or down shape. It may also be useful to provide trajectories starting from the surface pad based on parameters from deviated and horizontal drilling technology (Butler, 1994). This information could be used to identify areas with a high probability of well collisions and be involved in the surface pad optimization procedure. Another point of future research for well trajectory optimization is to work with detailed 3D models of individual drainage areas to provide a more detailed assessment of recovery and more accurate well trajectories for field application.

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* Title subject to change

Figures

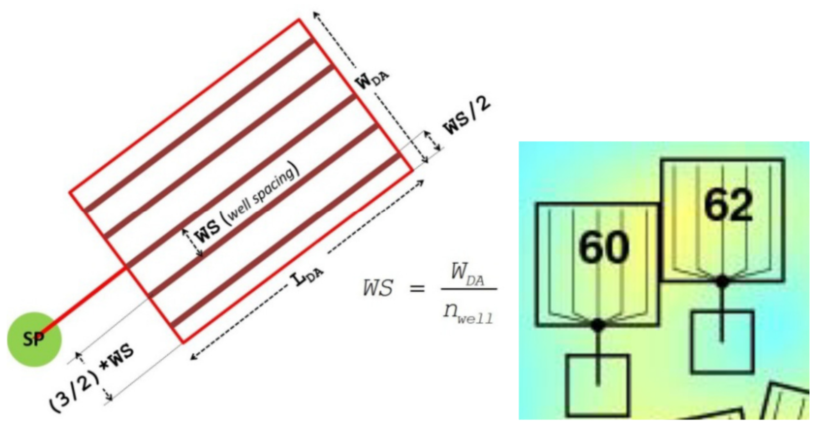

Figure 1: Examples of drainage areas from previous CCG papers on DA optimization.

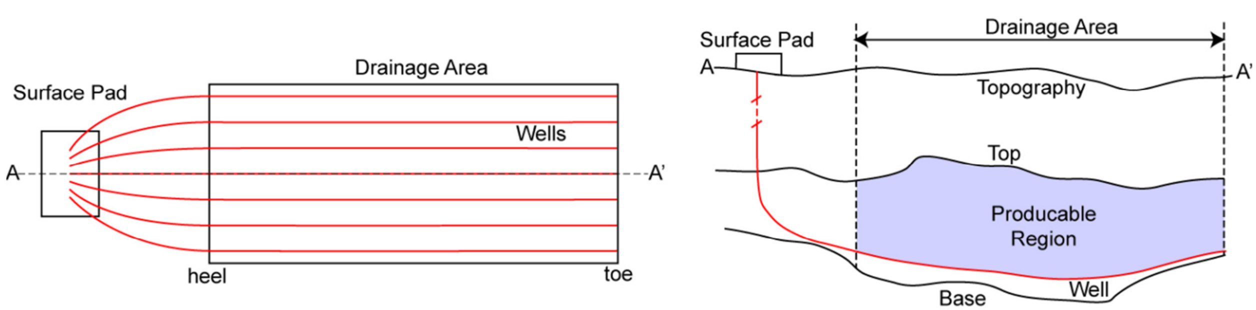

Figure 2: Top view of DA and SP layout (left) and cross section showing deviated well and producible region (right). Steam injector not shown.

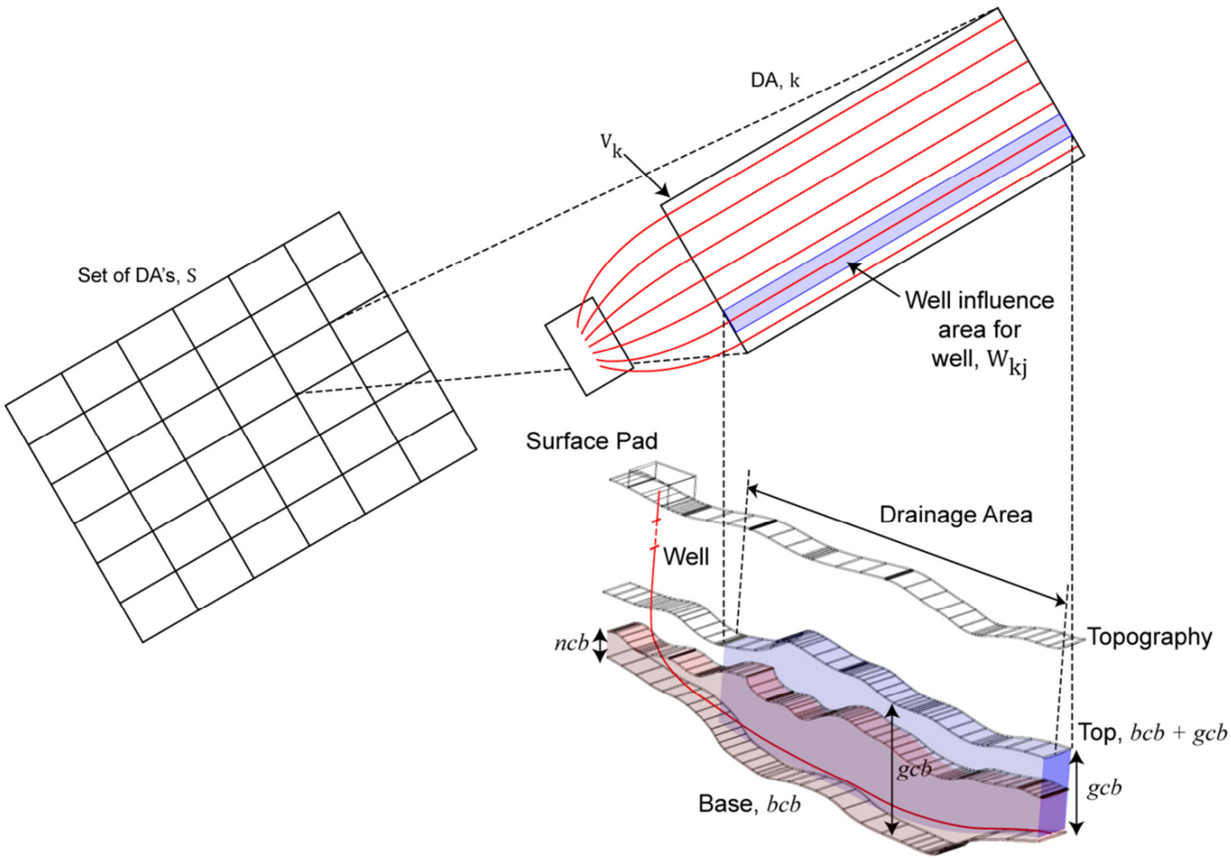

Figure 3: Schematic of a set of drainage areas, individual DA, and producible volume along the area of influence of a well. Note that ncb is a total net continuous thickness shown symbolically using a surface for comparison to gcb, but it may actually be distributed throughout the total thickness differently.

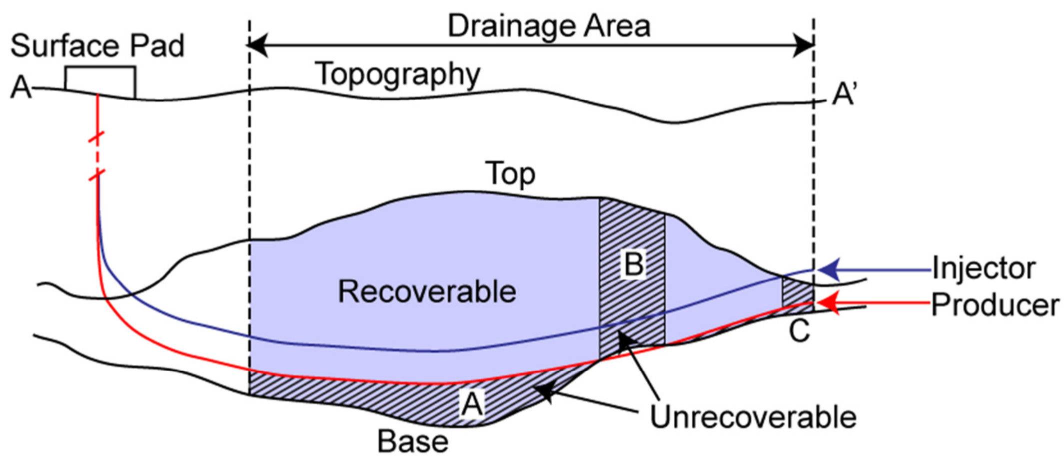

Figure 4: Potential recovery from a well and losses due to A – producer being above the base; B – producer is below the base; C – injector is above the top.

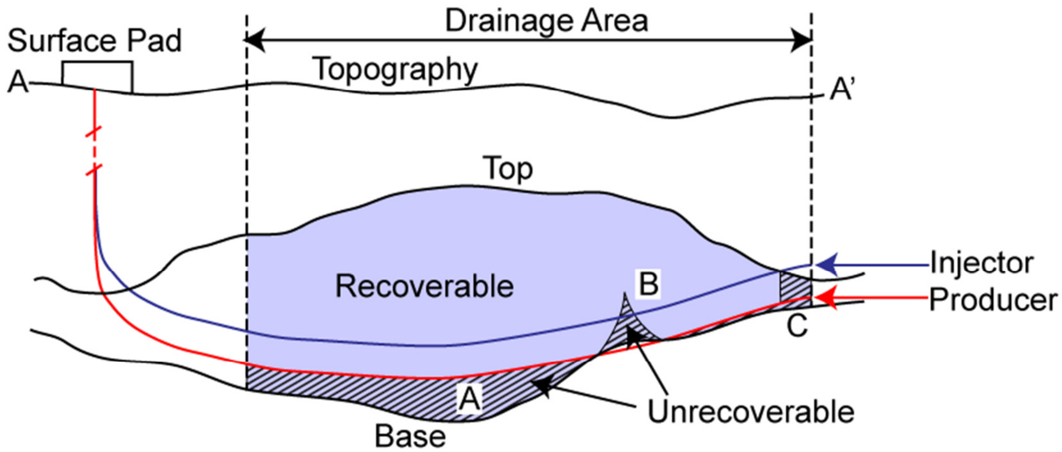

Figure 5: Similar to Figure 4, where loss in B is bounded by a drainage profile from injecting steam for some time *t*.

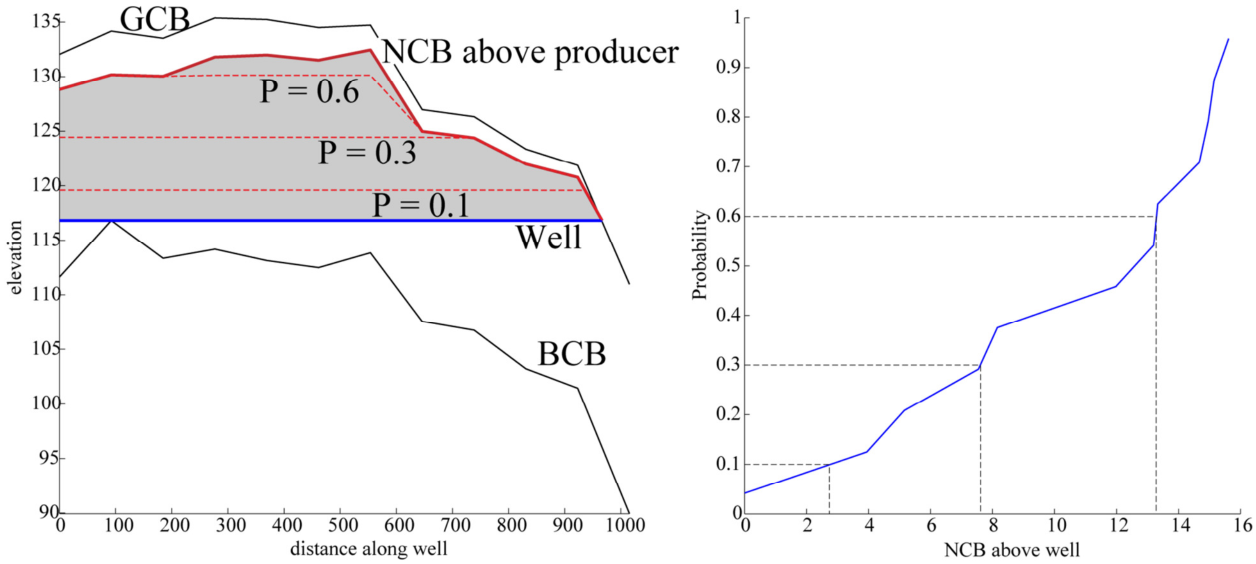

Figure 6: Example of producible thickness for a production well (left) based on different quantiles of the distribution of steam chamber thickness above the well (right).

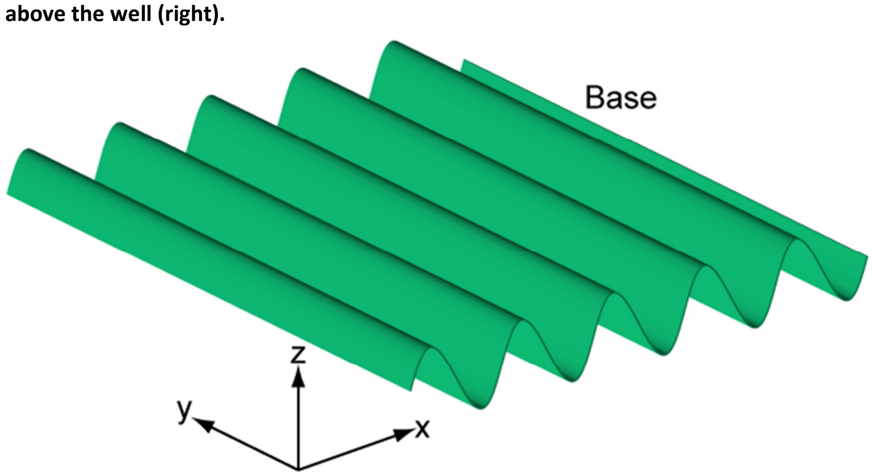

Figure 7: Hypothetical base surface. Roughness is accounted for by the losses where a well trajectory is above or below the base. Only for wells oriented in y is the loss minimized.

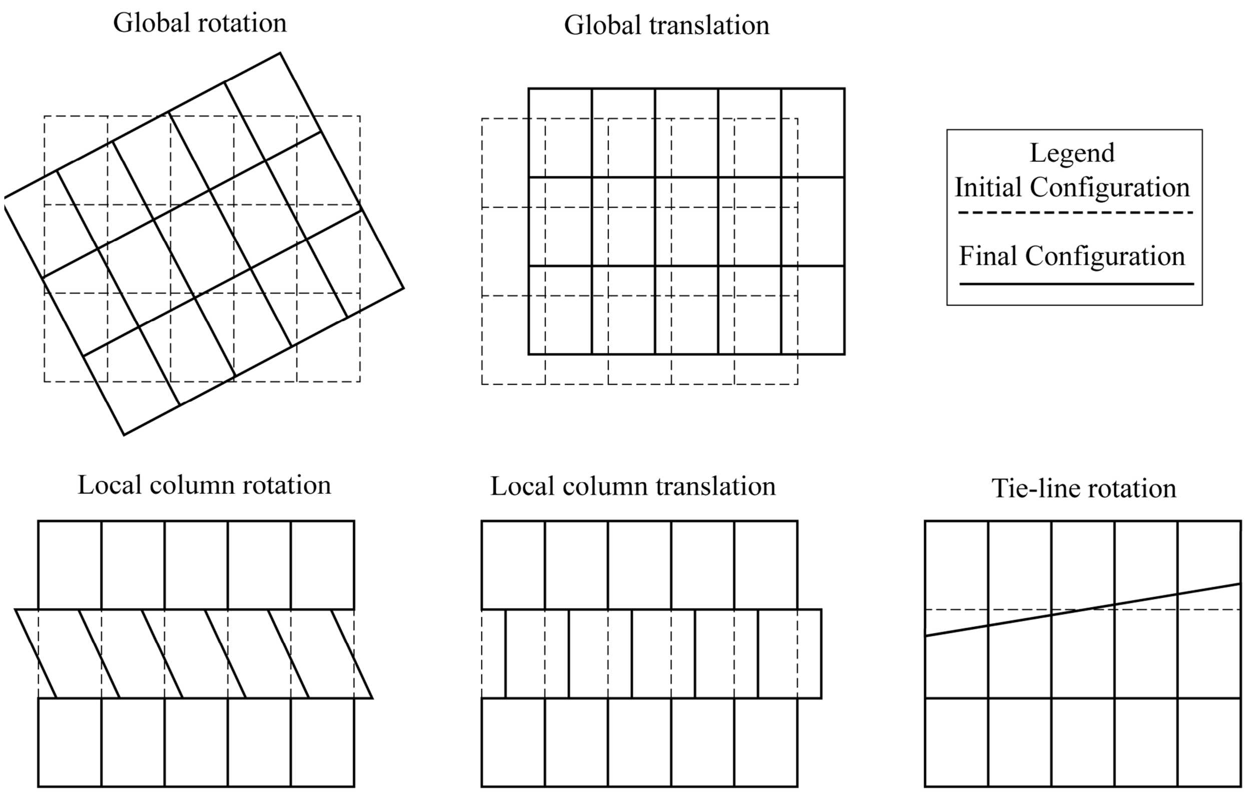

Figure 8: Examples of possible geometric transformations applied during optimization

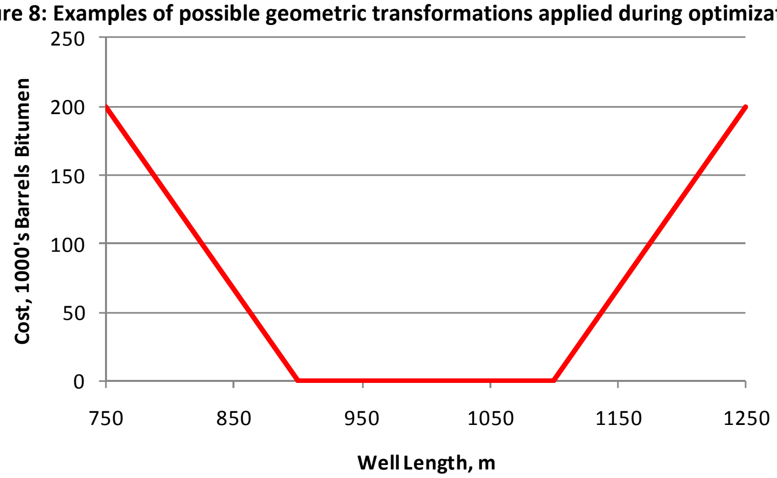

Figure 9: Example of a well cost function where additional cost is incurred if the well is outside the target length range of 1000 ± 10 % m.

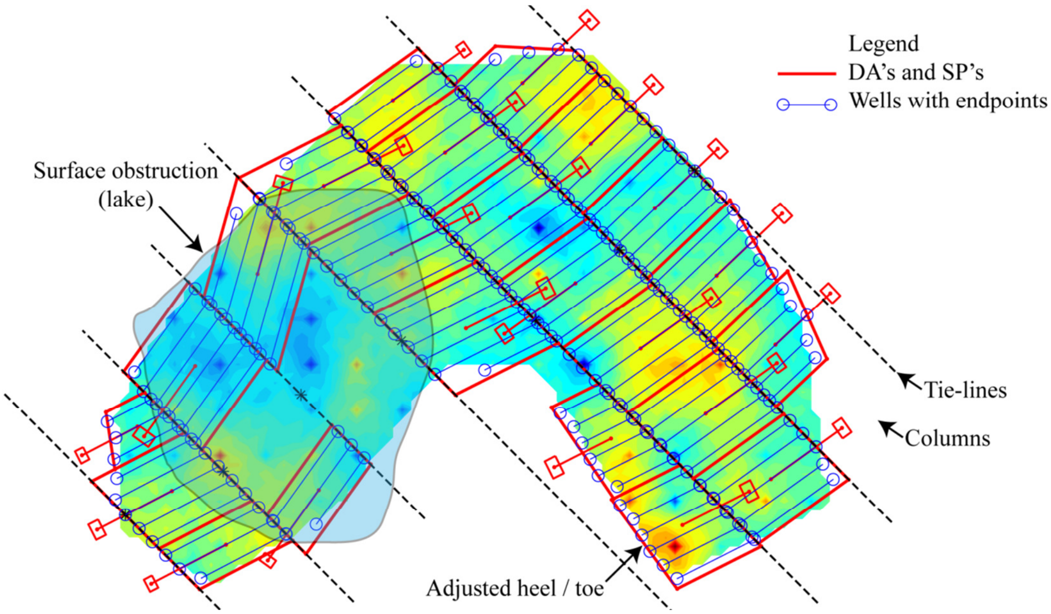

Figure 10: DA/SP configuration showing various geometric features and flexibility. Each DA was permitted to have between 3 and 8 wells. Varying sizes of surface pads is visible. The shaded map is an arbitrary surface of ncb. Heels and toes are automatically adjusted if wells fall outside a boundary or high quality zone.

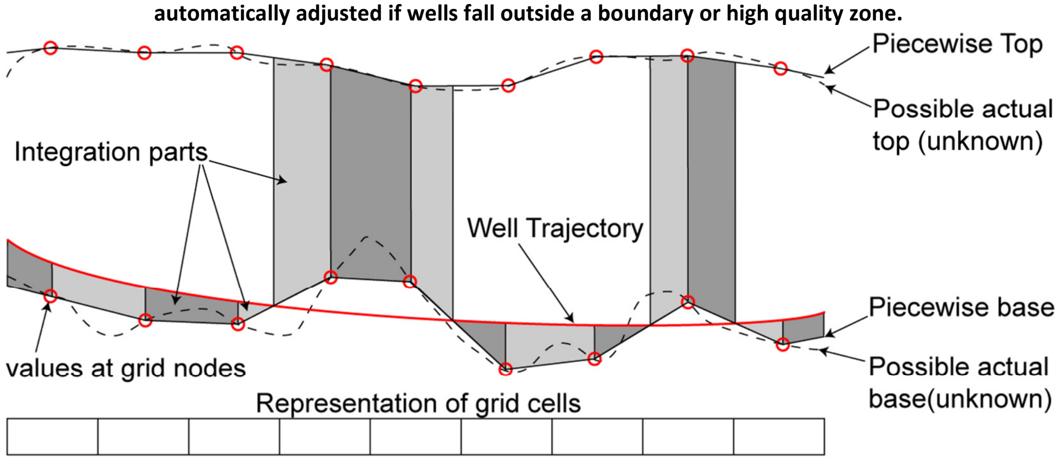

Figure 11: Schematic of regions involved in integration-by-parts to evaluate recovery loss from a well.

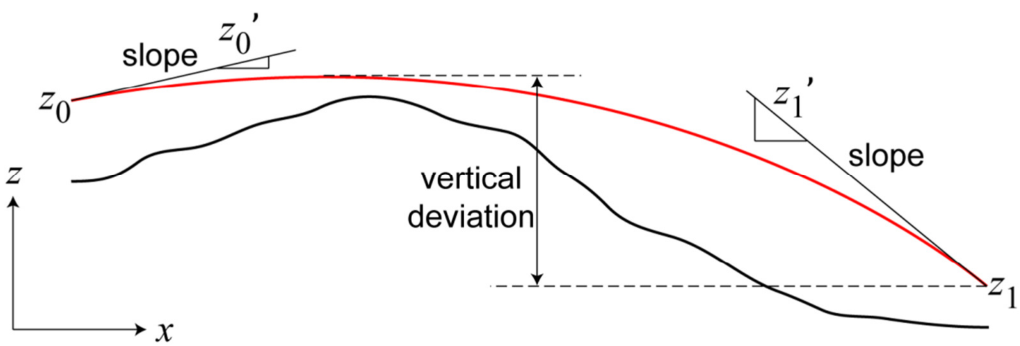

Figure 12: Constrained components of a well including the endpoint slopes and vertical deviation from highest point to lowest point along the well trajectory.

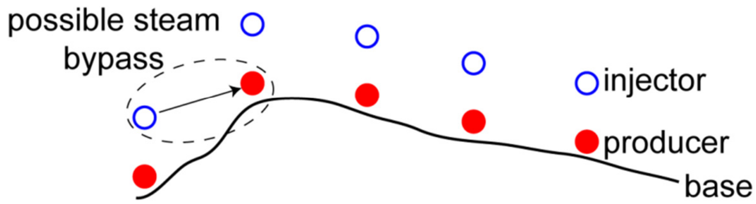

Figure 13: Scenario for steam bypass when a producer is above a neighboring injector.

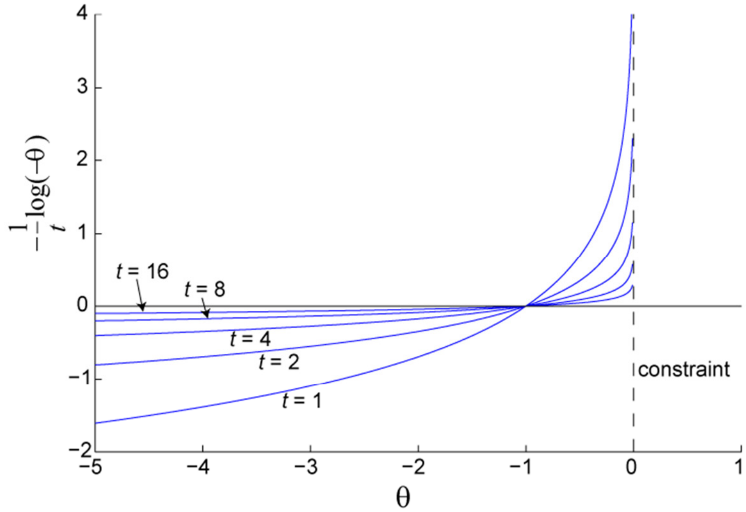

Figure 14: Logarithmic barriers for various values of t.

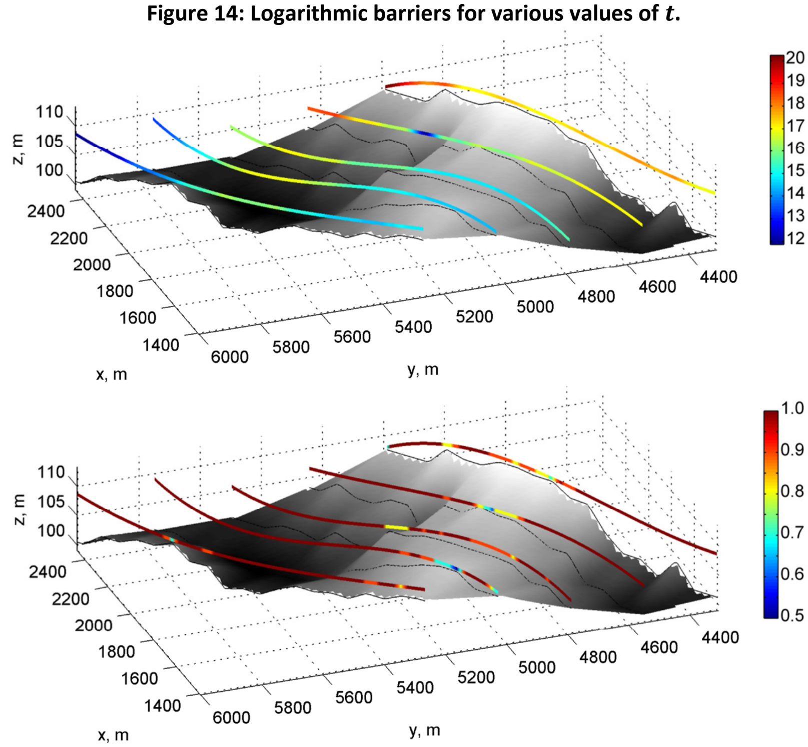

Figure 15: Optimized well trajectories for a five well drainage area. Wells are shaded by the expected value of ncb over 10 realizations in the top and by probability of being effective in the bottom. The expected base surface is shown. Wells were constrained by a maximum slope of 5 degrees and vertical deviation of 5 m.

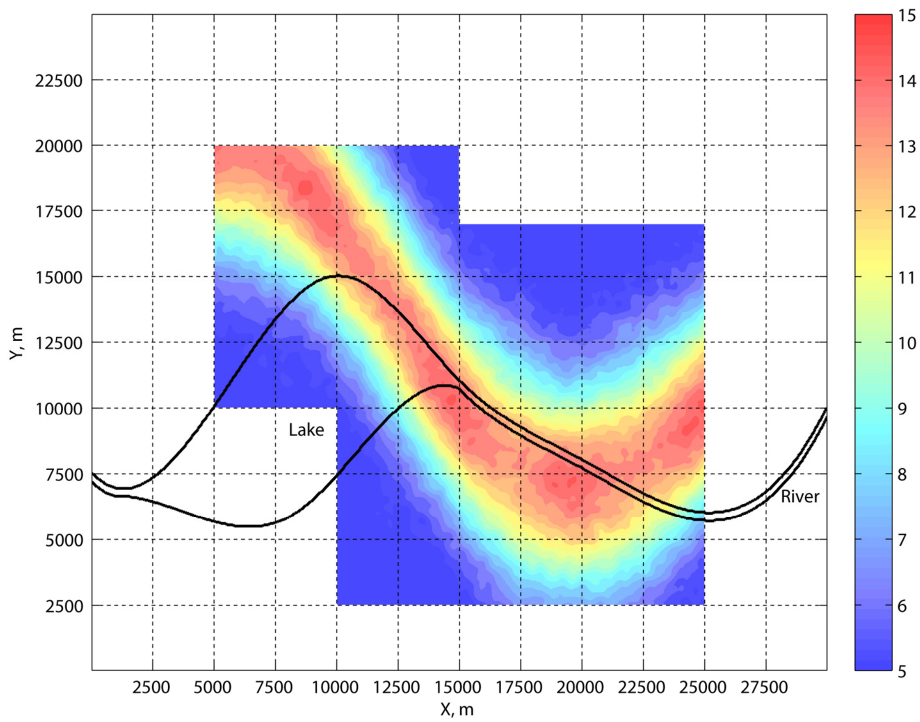

Figure 16: NCB surface for Example 2 in an area of interest with a surface obstruction in the form of a river and lake.

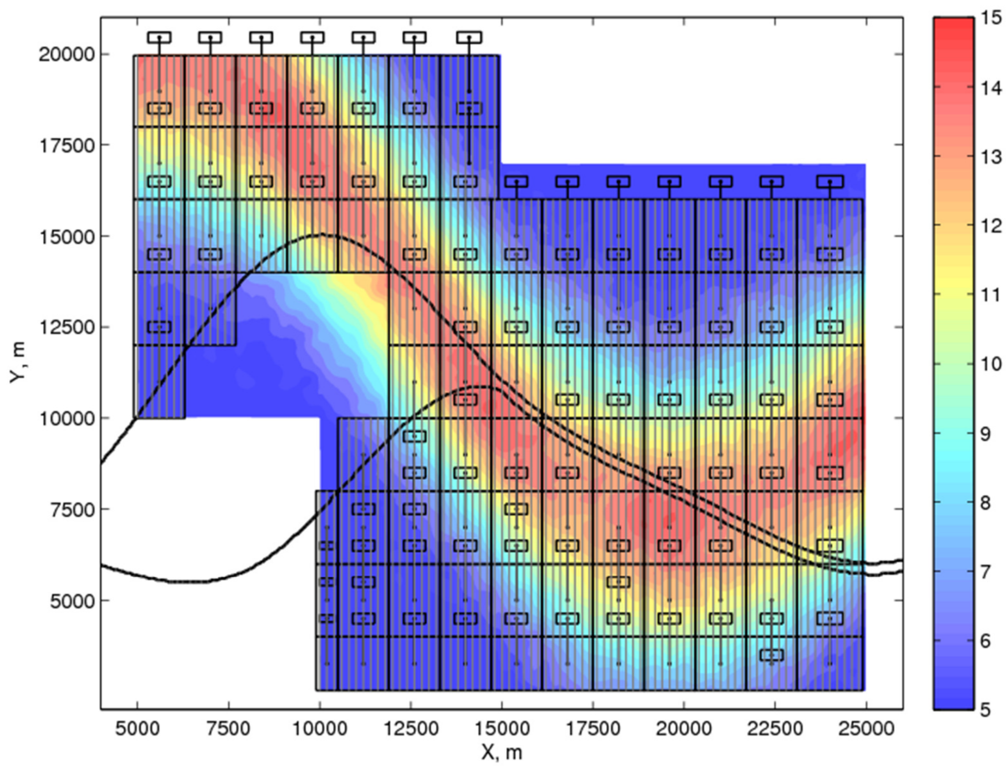

Figure 17: Initial DA configuration for Example 2.

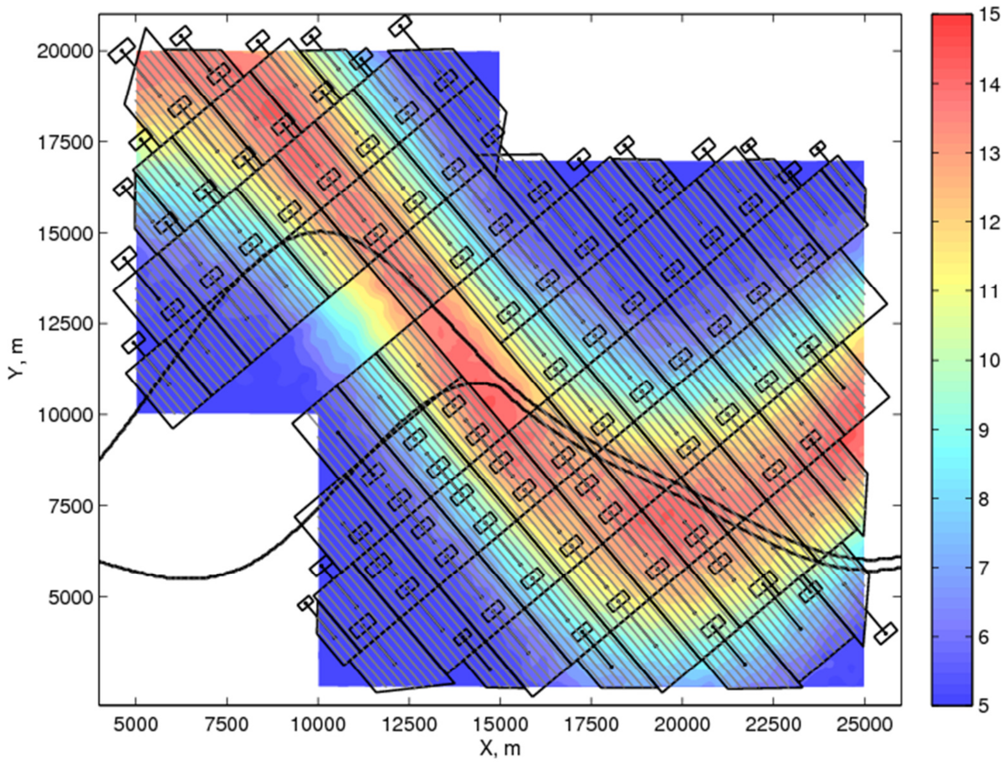

Figure 18: Final DA configuration using global rotation optimization for Example 2.

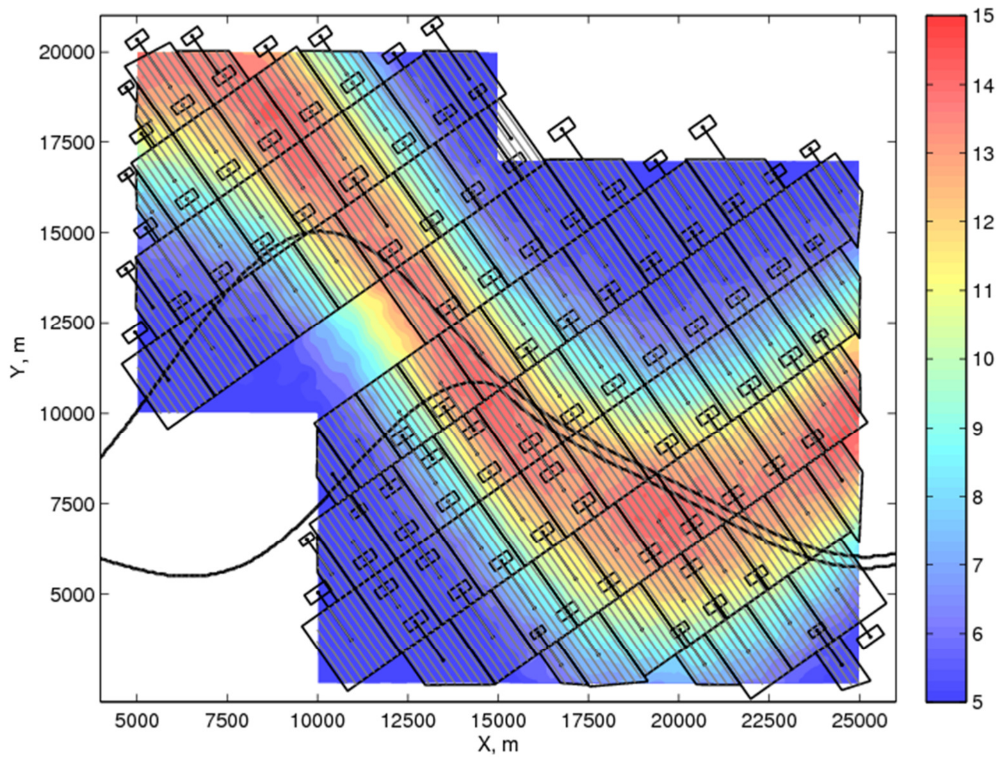

Figure 19: Final DA configuration using global rotation optimization coupled with global translation optimization for Example 2.

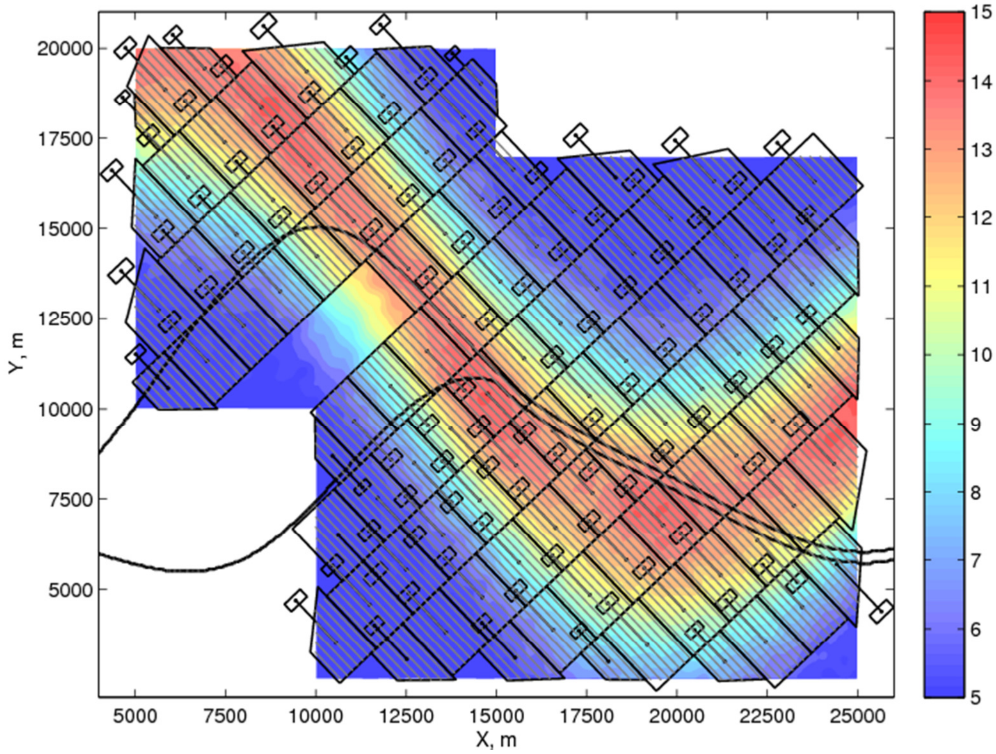

Figure 20: Final DA configuration using global rotation optimization coupled with column translation optimization for Example 2.

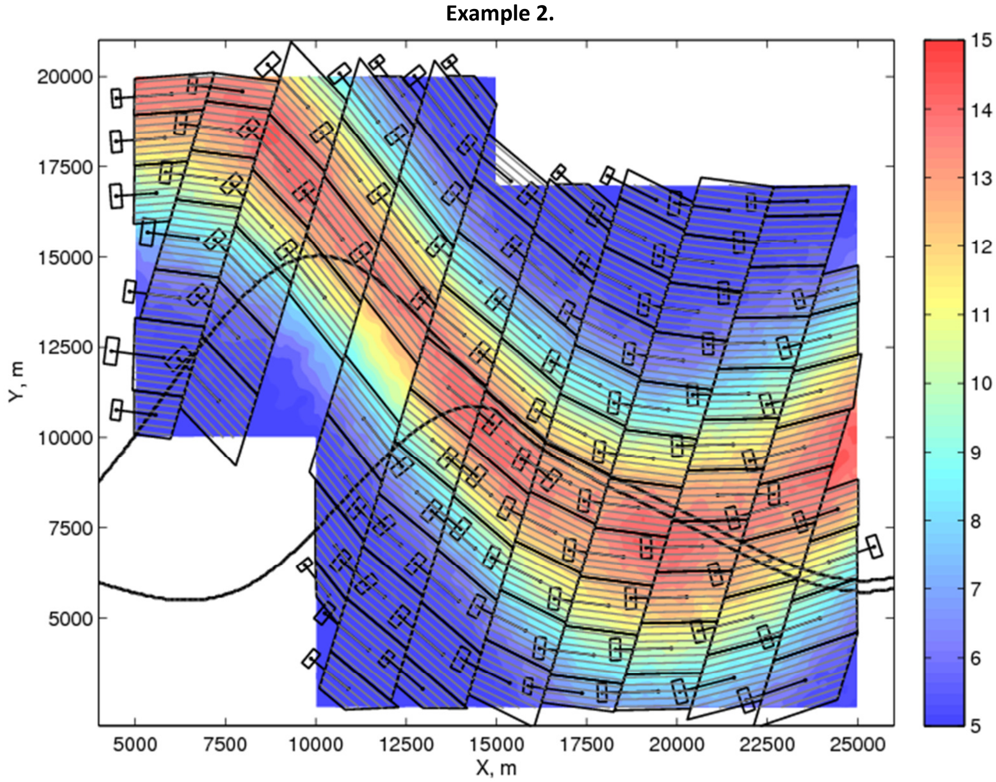

Figure 21: Final DA configuration using global rotation optimization coupled with column rotation and column translation optimization for Example 2.