MEMO: Reservoir MODELING NOTES
Joe Batir
June 2018
NREL-DOE Contract *DE-FOA-0001601*
SMU – Southern Methodist University Geothermal Laboratory, Huffington Department of Earth Sciences

Notes:
BEG – Bureau of Economic Geology, University of Texas, Austin

The models examined for the reservoir numerical modeling include the NREL (Esposito and Augustine (2011); Porro et al., 2012); TOUGH2 Geopressured Reservoir Production model; BEG Lumped Parameter model (Uddenberg, (2012); Zafar and Cutright, 2014); and SMU-Cornell GPFA-AB Reservoir Productivity Index model (Camp et al., 2018).

a. Order of work accomplished
    i. SMU-Cornell Reservoir Productivity Index model
    ii. Lumped Parameter model
    iii. TOUGH2 model
        1. This is pending based on efficiency of time/money and improvements it will provide. Cornell is discussing writing a TOUGH2 model that we will consider incorporating.

DATA PROCESSING, NOTES and MODELING STEPS

1) Calculate new heat flow and temperature-at-depth values for well sites

a. Utilizing Jared Smith 1D heat flow code (Smith et al., 2015; Jordan et al., 2017) to calculate heat flow for:
    i. Newly collected BHT from unexamined wells
    ii. BEG BHT database
        1. Note: There is a temperature disparity between the SMU database and the BEG database – It looks like the BEG database utilizes the SMU corrected temperature data
            a. Will use the BEG 'uncorrected' temperatures for the heat flow calculations as 'corrected'.

STEPS:

1) Make point data layer in ArcGIS of all the wells used for study
2) Import Surface Temperature layer into ArcGIS (Gass, 1982)
3) Import Sediment thickness layer into ArcGIS
4) Import Formation tops – Travis Peak/Hosston/Sligo, Cotton Valley, and Haynesville – into ArcGIS (see Formation Tops memo for details)
5) Get residuals of Sediment thickness: Top of Pettitt/Rodessa/Sligo, Top of Travis Peak/Hosston, Top of Cotton Valley, Top of Bossier, and Surface Temperature for all well locations.
6) Create data input file to go into the Heat Flow calculation code

a. Read how in the read me file in the heat conduction code folder
b. Make the top of the formations three of the depths to calculate temperature at

7) Calculate new heat flows and temperature at depth using Jared Smith Python code
8) Grid the heat flow data into a contour layer in ArcGIS using all the heat flow data
    a. Search "interpolate" in ArcGIS help and choose the interpolation/gridding method of choice
    b. Kriging is the gridding method for this project
9) Map Temperature-at-Depth layers
    a. Calculate the temperature layers for the Tops of each the formations of interest, 50, 80 and 100°C, and 2 to 5 km depth intervals.

2) Determine reservoir properties for the study area

a. Measure net sand thickness
    i. From gamma ray logs
    ii. From literature sources
b. Measure porosity and permeability
    i. From porosity logs
    ii. From literature sources
    iii. Calculate using the Initial Pressure (IP test) and the net sand thickness following BEG methods
c. Calculate Fluid Viscosity
    i. Assuming water
        1. If we have TDS, will incorporate
    ii. Calculate viscosity based on temperature, salinity, pressure
        1. http://petrowiki.org/Produced_water_properties#Viscosity

STEPS

1) Perform literature review to find previous publications with porosity/permeability, water saturation, water TDS and density, net pay/net sand thickness, and other information
    a. During literature review, put data into HyrdaulicProperties Content Model
2) Import well logs into Petra project for reservoir properties
    a. Gamma Ray and SP to determine net sand thickness
    b. Neutron logs and/or Density logs to determine Porosity
3) Depth Correlate well logs
    a. This requires many steps and is easier to read in the Petra manual
4) Digitize additional well logs as needed and time based on cross-sections
5) Pick sections of sand in formations of interest
6) Estimate porosity from the well logs for each sand section in formations of interest
    a. CHECK OUT THE WIKI PAGE TO MAKE SURE YOU ARE DOING THIS RIGHT
        i. http://wiki.aapg.org/Density-neutron_log_porosity
7) Calculate an average net sand thickness and average porosity for each formation

8) Input average net sand thickness and average porosity for each formation into the content model.
9) Input permeability data – MAKE SURE TO NOTE THE TYPE OF PERMEABILITY MEASUREMENT
    a. IF permeability data came from a helium gas measurement, convert to a fluid permeability following the corrections outlined in GPFA-AB memo 11 p.10
    b. IF no permeability data – use a porosity-permeability empirical relationship
        i. These should be found in the literature for specific fields.
        ii. There may be a formula for using IP tests and formation thickness following BEG's work, but this has not been found yet.
10) Calculate fluid viscosity based on the temperature following Table 2 in GPFA-AB memo 11 p. 9
    a. If we have TDS information, we should see how TDS impacted fluid viscosity, see http://petrowiki.org/Produced_water_properties#Viscosity

3) Calculate Reservoir Productivity Index (RPI)

a. Calculate within the spreadsheet or Matlab if doing the Monte Carlo simulation
    i. Note: The Reservoir Productivity Index (RPI) value presented in the Reservoir Content model from Cornell is the most likely RPI value from a 100,000 iteration Monte Carlo simulation using the RPI parameters and the RPI parameter uncertainties and distribution. This was written as a Matlab code and then brought into the working spreadsheet
    ii. Parameters needed:
        1. Permeability (m^2)
        2. Reservoir thickness (m)
        3. Fluid viscosity (Pa-s)
        4. Distance between production and injection wellbores (m) – this is assumed to be 1000 m
        5. Wellbore radius (m) – this is assumed to be 0.1 m

STEPS

1) Confirm all necessary data are in HydraulicProperties content model
2) Open and run the RPI-MonteCarlo Matlab code
    a. This code will calculate an RPI for each data point within the HydraulicProperties content model
3) Confirm Reservoir content model has been filled in from the output of the RPI-MonteCarlo Matlab code
4) Generate Table for report of parameters and results

4) Calculate Heat-in-Place within the Reservoir

a. Calculate reservoir area size to estimate the total heat in place
   i. Divide the 10 km radius into four sections that can be then subdivided into smaller footprint areas
b. Estimate of porosity (from well logs and published data)
c. Estimate of thermal gradient through formations (based on corrected BHT data)
d. Follow the Zafar and Cutright (2014) model for this.
   i. Inputs to heat in place – called [integration]:
      1. Thermal heat capacity (J/cm^3*C) of the formation
      2. Grid Cell Size of the bottom-surface raster (m)
      3. Gradient raster (°C/m) – gradient within the formation of interest
      4. Bottom surface raster (m) – bottom of the volume of interest, i.e. base of the formation
   ii. Note: this calculates the heat in place per cell size block of the grid, and then the total heat in place for a study area is all of the cells added together.

STEPS

1) Generate study area polygon in ArcGIS
   a. This is the 20 km radius from the power plant – needs to be converted to make sure it is in fact a polygon
2) Bottom surface raster – This raster will be the base of the formation of interest, which is equal to the top of the formation below
   a. In the Zafar and Cutright paper, generating this layer was done using Inverse Distance Weighting (IDW) with the default number of points, weighting power, and cell size
   b. This raster should generate a cell size which is then used as part of the calculations
3) Top Surface raster – This raster will be the top of the formation of interest
   a. Make sure the cell size for the Bottom and Top surface raster files are the same, they will both be generated using the same data, but confirm to make sure they are the same cell size.
4) Obtain a thermal heat capacity for the formation of interest
   a. This should be able to be estimated from rock type, porosity, and water content
5) Calculate [integration] for all cells
   a. Following the equation given

$$[integration] = \rho_c * [cell\ size]^2 \left([gradient\ raster] * \left[\frac{\{bottom\ surface\ raster\}^2}{2} - \frac{\{\ top\ surface\ raster\}^2}{2} \right] \right)$$

6) Sum all of the [integration] values for the study area

5) **Calculate Potential Reservoir Production using the BEG Model used for Texas in NGDS project**
   a. Use Lumped Parameter model following Matthew Uddenberg thesis (2012)
      i. Thesis describes method for using reservoir parameters for total potential, pressure and temperature decline curves based on production rates.

1. Examples show the ability to model a reservoir and estimate power production over time – this empowers the user to model reservoir development for a specific design purpose to limit the chance of early thermal breakthrough
2. The full model overlaps with economic aspects of the outputs from the GEOPHIRES program that is being used for the surface calculations by the NREL team for this project.

ii. Parameters and Matlab Code explained in the Uddernberg thesis
1. Define parameters for our specific project and run model
2. Update the model to accept .xls as inputs to run multiple scenarios

STEPS:

1) Load matlab script .m file
   a. Either copy and paste from Matt Uddernberg's thesis, or use script associated with the ETX-DDU project, which should be uploaded as an appendix (LumpedParameterModelETX.m)
2) Define reservoir properties within script
   a. As of 13 July 2018, the script has not been updated to read in an .xls to run multiple scenarios and reservoir models are still run one by one, which requires all reservoir properties to be defined at the beginning of the script.
   b. The excel file 'JFB_LumpedparameterModelvalues.xlsx' gives the original values used in Uddenberg (2012) and has several models values used for the ETX project
   c. Values that need to be assigned include all values within the Initial inputs for the block model (lines 3 through 31)*, and porosity(1), P(1), and T(1) in the initial values for the internal tank (lines 65, 68, and 69, respectively)**
      i. *Note 1* - The timeframe for this model is 20 years – the time should not be changed because currently all the vector arrays are assigned a length of 20 years, in hours – this should be fixed so that the timeframe for the model can be variable
      ii. **Note 2** - This values should also be set prior, preferably read in and assigned from an .xlsx file – this should be fixed for future ease of use
3) Run model
   a. Current figure outputs include:
      i. Temperature vs. Time (which is reservoir temperature) and Well Temperature vs. Time
         1. These are measurements of the temperature to see if there is thermal breakthrough during the planned life of the well
      ii. Production Wells Necessary vs Time
         1. This is the number of production wells that are necessary to produce the desire amount of fluid flow given the size of the bottom hole – the number of wells necessary would be double this, assuming all the fluid is re-injected
      iii. Pressure vs. Time and Heat Output vs. Time

1. These are more plots to examine the health of the potential reservoir versus the desire production

4) Change parameters for new reservoir, and re-run
   a. Currently, the model is set up as a single run model, the program needs to be updated so that the model will run multiple scenarios in a single execution. For now, after the final outputs are produced, they need to be saved, and then the .m file updated with the new reservoir parameters, and then re-run.

6) Other Reservoir Models considered and determined not to incorporate

a. TOUGH2 model to see how reservoir will change with time.
   i. This will be done if there is time, data, and a code completed by another team.
b. Frone – West Virginia thermal model
   i. 2D Advection-Diffusion model that is run until a steady state is reached
   ii. Models to see if the WV heat flow anomaly can be explained with simple conduction
      1. Does not model fluid flow or temperature depletion with time.
   iii. Determined to not match our project research
c. Frone – Cascades 3D thermal model
   i. 3D conduction model
      1. Accurately ties model to data
      2. Does not account for fluid flow within the model, cannot model reservoir production and temperature/pressure draw down.
   ii. Determined to not match our project research

REFERENCES

Camp, Erin R., Jordan, T.E., Hornbach, M.J. and Whealton, C.A., 2018. A probabilistic application of oil and gas data for exploration stage geothermal reservoir assessment in the Appalachian Basin. *Geothermics*, *71*, pp.187-199.

Esposito, Ariel,; Augustine, C., 2011. Geopressured Geothermal Resource and Recoverable Energy Estimate for the Wilcox and Frio Formations, Texas, GRC Transactions V 35, 1563-1571.

Gass, T.E., 1982. Geothermal heat pumps, Geothermal Resources Council Bulletin, 11, 3-8.

Porro, C., Esposito, A., Augustine, C. and Roberts, B., 2012, September. An estimate of the geothermal energy resource in the major sedimentary basins in the United States. In *Geothermal Resources Council Transactions, Geothermal Resources Council 2012 Annual Meeting* (pp. 1359-1369). http://pubs.geothermal-library.org/lib/grc/1030408.pdf

Smith, Jared, Horowitz, F. Whealton,C., 2015. **Thermal Model Methods, in Appalachian Basin Play Fairway Analysis: Thermal Quality Analysis in Low-Temperature Geothermal Play Fairway Analysis, Geothermal Data Repository** https://gdr.openei.org/submissions/638

Uddenberg, Matthew E. 2012 "An assessment of value for deep sedimentary geothermal resources in Texas." Master’s Thesis, University of Texas, Austin, 2012.

Zafar, S. Daniel, and Bruce L. Cutright. "Texas' geothermal resource base: a raster-integration method for estimating in-place geothermal-energy resources using ArcGIS." *Geothermics* 50 (2014): 148-154.