

# New TOUGH2 EOS modules for the simulation of geothermal reservoirs containing saline brines and non-condensable gases



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## TOUGH2 numerical reservoir simulator

The TOUGH2 numerical reservoir simulator developed at the Lawrence Berkeley National Laboratory (Pruess et al., 1999) is customarily used to model hydrothermal systems for both scientific and industrial purposes. The simulator uses a modular architecture (Fig. 1) which allows the modeling of different fluid mixtures and thermodynamical conditions with appropriate Equation Of State (EOS) modules. Classical TOUGH2 EOS modules delivered to the public and used for geothermal applications include **EOS1** for pure water; **EOS2** for water+CO<sub>2</sub>; **EOS4** for water+Vapor Pressure Lowering (VPL); **EOS7** for water+air+brine; and **EWASG** (Battistelli et al., 1997) for mixture of water, NaCl and one Non Condensable Gas (NCG). EWASG evaluates brine properties as a function of P, T and NaCl content; simulates solid salt precipitation as a consequence of brine boiling and related porosity and permeability changes; accounts for VPL due to suction pressure effects.

New modeling capabilities, recently developed by Saipem SpA for environmental applications and for GHG and acid gas injection, can also be conveniently used for the modeling of hydrothermal systems. They include new compositional approaches for geothermal fluids containing mixtures of NCGs as well as new phase equilibria algorithms reliable in a wider range of P-T-X conditions.

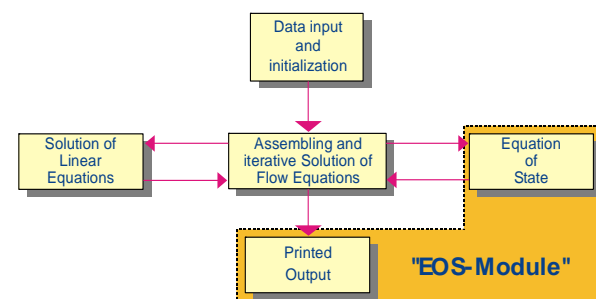


Fig. 1. - Modular structure of TOUGH2 numerical reservoir simulator (Pruess et al., 1999). Programming of new EOS modules allows to solve problems in very different fields of application.

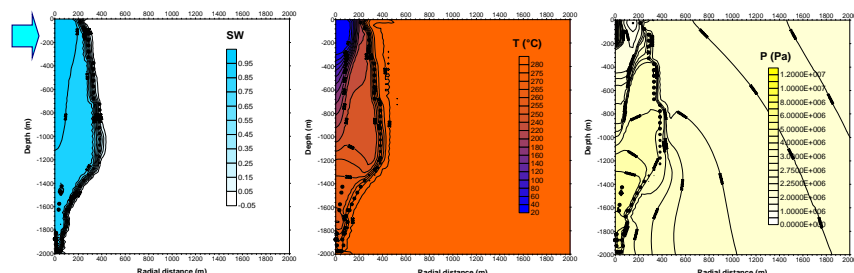


Fig. 3 - EWASG EOS: distribution of aqueous phase saturation (SW), temperature (T), pressure (P), and halite saturation (circles) after 30 years of NaCl brine injection (Calore and Battistelli, 2003). Halite precipitation occurs at the edge of the liquid brine plume where the water vaporizes.

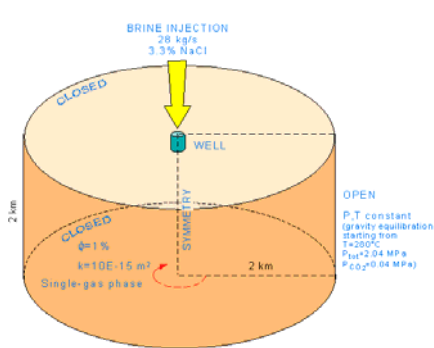


Fig. 2 - EWASG EOS: conceptual model for NaCl brine injection in a depleted vapor dominated reservoir at a well sector scale. (Calore and Battistelli, 2003)

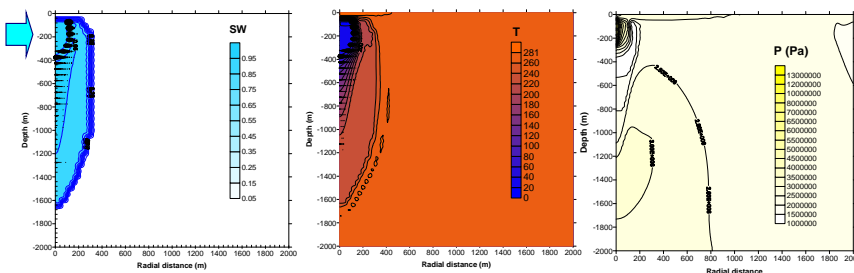


Fig. 4 - EWASG EOS: distribution of aqueous phase saturation (SW), temperature (T), and anhydrite saturation (circles) after 30 years of calcium sulphate brine injection (Saipem, 2009b). Anhydrite precipitation occurs in the interior of liquid brine plume at the thermal front where injected brine is warmed up.

## Enhanced EWASG EOS module

EWASG (Battistelli et al., 1997) was developed to model geothermal reservoirs containing remarkable amounts of NaCl dissolved in the brine and of NCGs, customarily described using CO<sub>2</sub> which is usually the most abundant gas found in geothermal fluids.

EWASG has been recently enhanced (Saipem, 2009a) with: new correlations to evaluate brine density; the inclusion of NCG effects on brine density; the modeling of NaCl partitioning in the gaseous phase; the use of the Spycher and Reed (1988) virial EOS to compute the density of binary mixtures of steam and CO<sub>2</sub>, CH<sub>4</sub> or H<sub>2</sub> at high pressures; the modeling of CO<sub>2</sub> and CH<sub>4</sub> dissolution in the aqueous phase using the Spicher and Reed (1988) virial EOS for the calculation of fugacity coefficients in the gas phase and the Poynting correction.

EWASG was already used to model at the well sector scale (Fig. 2) the injection of a sodium chloride brine into a high temperature depleted vapor-dominated reservoir (Calore and Battistelli, 2003). Solid salt precipitation (halite) occurs at the edge of the liquid brine plume where water vaporization takes place (Fig. 3).

The same conceptual model has been recently used to simulate the injection of a calcium sulphate-dominated aqueous solution (Saipem, 2009b). Calcium sulphate is modeled instead of NaCl and solid precipitation occurs when anhydrite saturation is reached. As anhydrite solubility decreases with temperature, anhydrite precipitation occurs within the plume of liquid water at the boundary of the zone cooled by injected water (Fig. 4).

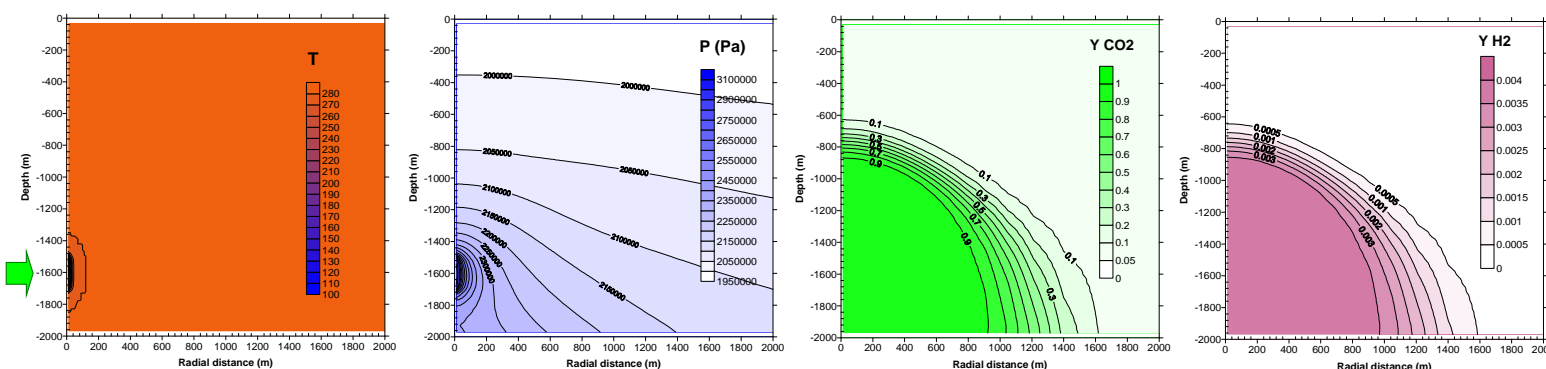


Fig. 5 - TMVOC V.2 EOS: distribution at well sector scale of temperature (T), pressure (P), CO<sub>2</sub> and H<sub>2</sub> mass fraction in the gas phase after 10 years of NCG injection in a high temperature depleted vapor-dominated reservoir. Original NCG content is 4.55% by mass. Reinjecting NCG mixture (2 kg/s) composition is: 90% CO<sub>2</sub>, 8% H<sub>2</sub>, 2% H<sub>2</sub>S, on a molar basis.

## TMGAS EOS module

TMGAS was developed to study the geological sequestration of GHG mixtures and the disposal of acid gas mixtures produced from sour hydrocarbon reservoirs (Battistelli and Marcolini, 2009). It can accurately model the two-phase equilibrium between NaCl brine and non-aqueous phase mixtures made up by both organic and inorganic components up to pressures of ~100 MPa and temperatures of ~260°C. In addition to GHG and oil field applications, it can be used to model the exploitation of hydrothermal systems characterized by high NCG partial pressures. An example is the study of heat extraction from deep EGSs in which CO<sub>2</sub> is used as circulating fluid instead of water, as suggested among others by Pruess (2006).

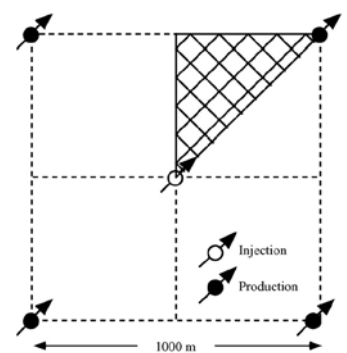


Fig. 6 - 5 spot well pattern to exploit an EGS with either water or CO<sub>2</sub> (after Pruess, 2006). P=500 bar abs, T=200°C.

Pruess (2006) modeled the EGS exploitation (Fig. 6) either with water or CO<sub>2</sub> as circulating fluid, in the latter case starting with the system already saturated by pure CO<sub>2</sub>, due to the limitations of the EOSM module used.

TMGAS can replicate the Pruess (2006) simulations (Fig. 7a and 7b) and can also model the injection of CO<sub>2</sub> in the hydrothermal reservoir initially saturated by water at 200°C and 500 bar abs (Spycher and Pruess, 2009). The simulation shows that the same heat extraction is reached after a transient of about 5 years (Fig. 8b). Produced fluid mixture contains liquid water for about 2 years and water dissolved in the CO<sub>2</sub> non aqueous phase for a total of about 5 years (Fig. 8a). This suggests that casing corrosion in the production well is a critical issue both in the initial two-phase production phase, and also after the disappearance of the aqueous phase. Due to the high content of water vapor in produced CO<sub>2</sub>, water condensation will likely take place along the production well and in the heat exchanger due to fluid temperature and pressure decrease. Transient production parameters need to be carefully taken into account for proper operation of the power plant during the initial life of EGS.

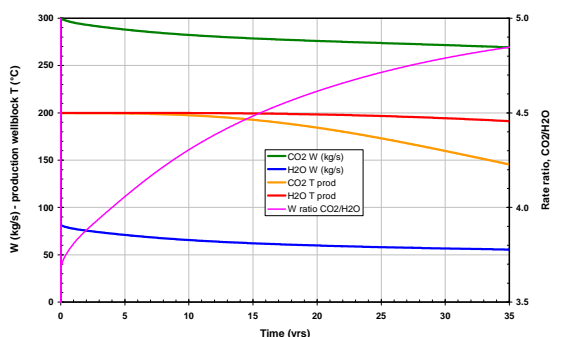


Fig. 7a - TMGAS EOS: rate extraction from a 5 spot well pattern EGS operated with water or from the beginning with CO<sub>2</sub> (after Pruess, 2006).

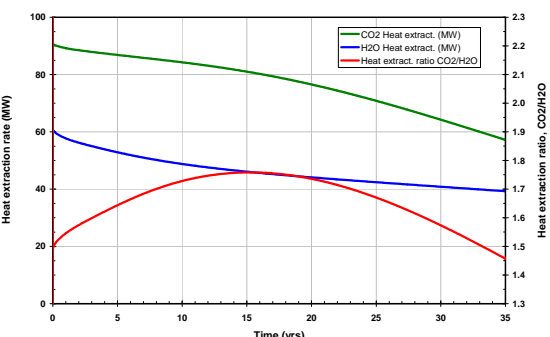


Fig. 7b - TMGAS EOS: heat extraction from a 5 spot well pattern EGS operated with water or from the beginning with CO<sub>2</sub> (after Pruess, 2006).

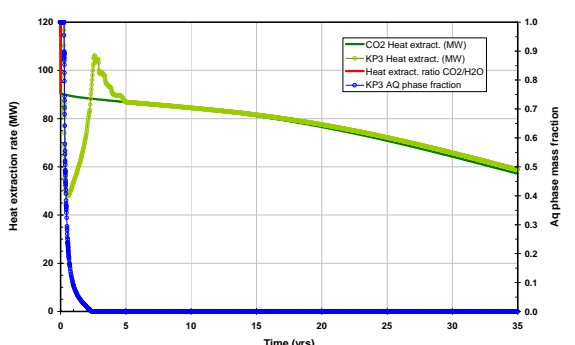


Fig. 8a - TMGAS EOS: rate extraction from a 5 spot well pattern EGS operated with CO<sub>2</sub> starting from a water-saturated medium.

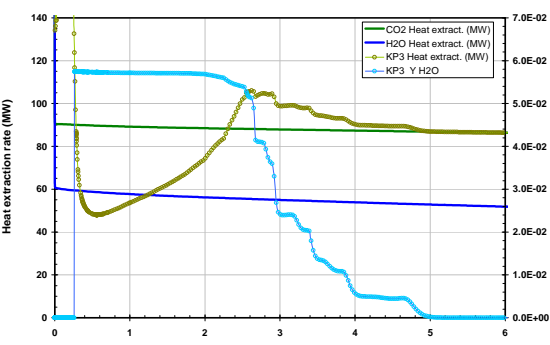


Fig. 8b - TMGAS EOS: heat extraction from a 5 spot well pattern EGS operated with CO<sub>2</sub> starting from a water-saturated medium.