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A REGIONAL INTEGRATED ASSESSMENT MODEL FOR ENERGY DEVELOPMENT:
THE CASE OF OIL SHALE

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Introduction

The aim of this report is to describe the *Regional Integrated Assessment Model for Energy development*, *ReIAME*, a decision support tool to evaluate alternative development options and associated impacts of basin-scale energy development. *ReIAME* is a dynamical integrated assessment model that provides decision makers and stakeholders with a tool to assist them in addressing a variety of questions and concepts for basin-scale fuel development. Some of these questions are:

- How will water and other resources affect process and project economics and industry development?
- What infrastructure such as water supply is needed to support regional fuels development under different development scenarios and under potential climate change scenarios?
- What are the social and economic implications of different energy development scenarios?
- What are the effects of policies for water and carbon on energy development?

Case Study

ReIAME is specifically modular and extensible with the intention of being readily applicable to distinct geographical areas and energy resource evaluations such as natural gas and unconventional fuels. However, the emphasis of the study in this report is to apply *ReIAME* to oil shale industry development, primarily in the Picenance Basin of Colorado (Figure 1).

Due to the high volatility of prices and worrisome depletion of conventional liquid fuels, unconventional fossil fuels such as oil shale, tar sands, and coal to liquids have recently gained the attention by policy makers and investors. The largest reserve of oil shale in the world is located in the western interior of North America, and includes parts of Colorado, Utah, and Wyoming. It is estimated that a large-scale development of oil shale in this area could significantly reduce U.S. oil imports.

However, oil shale production carries a number of potential socio-economic and environmental impacts, both positive and negative. While domestic production of light oil would create jobs and contribute to GDP, Federal and State finances, fuel production associated with oil shale requires energy and water, among others, and could have negative impacts on air quality, water quality, habitat, and wildlife.

ReIAME enables a proper, science-based, integrated analysis of the cross-sectoral implications of the large scale development of the oil shale industry in the USA necessary to inform policy makers and avoid serious potential, and unexpected, negative impacts. Specifically, *ReIAME* evaluates potential production capacity of unconventional fossil fuels within the constraints of environmental quality, land use, and socioeconomics. The model integrates the technical, environmental, economic, regulatory, and social processes involved with information flow and feedbacks among all of the modules. We focus on assessment of carbon and water resources issues, impacts, and management strategies associated with oil shale production for the specific application of basin wide in-situ oil shale development.

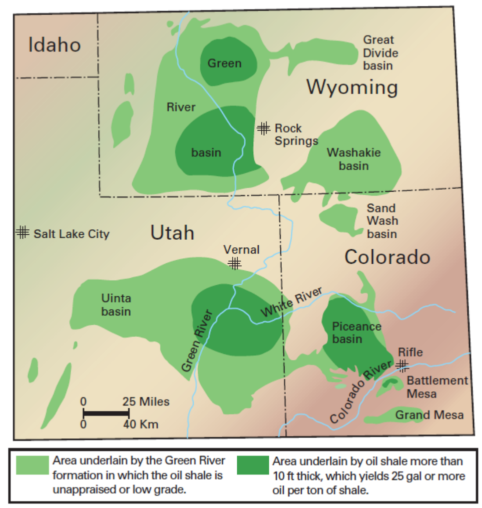

Figure 1 Oil shale resources in the Green River Formation in the Western United States (from DOE, 2008 and DOE Fact Sheets)

The *ReIMAE*, as applied here, simulates oil shale production approximating the Shell In Situ Conversion Process (Shell 2006), considering the dynamic phases of drilling, freezing, heating, producing, and reclamation. For basin-scale fuel production, sub-basin sized cells are developed and reclaimed sequentially, but, due to the timing of the different phases, activities can occur asynchronously in different cells. In each of the phases, energy and water requirements are computed as basin-wide production ramps up to a targeted rate. As the simulated industry grows throughout the region, economic and resource (e.g. water, energy, carbon, labor) requirements and limitations are tracked. Simulations demonstrate interdependencies among the multiple systems and resources as an industry ramps up, achieves steady state, and then ramps down.

Background

A large number of models are available for either the analysis of integrated energy systems or the cross–sectoral impact of proposed national policies. Few of them, however, encompass both aspects in a single holistic framework and fewer analyze sectoral settings such as oil shale. Market and behavior-oriented models, which are both causal-descriptive (e.g. system dynamics) or correlational (e.g. econometrics), and bottom–up optimization models (Bunn and Larsen, 1997) are normally employed to carry out energy analysis. Optimization energy models are generally built to find the optimal intervention that minimizes expected energy supply costs at any point in time, given a specific set of assumptions and constraints (Sterman 1988) The National Energy Modeling Systems (NEMS), developed by the Energy Information Administration (EIA) (EIA 2003a) and used to create projections presented in EIAs Annual Energy Outlook (AEO 2008) and specific policy analyses (e.g. the Waxman–Markey bill,(H.R. 2454 2009), is an optimization model. By comparison, correlational models, which are commonly based on optimization and econometrics, use historical data to define the model structure. They provide projections for the implementation of alternative technologies and development strategies using correlation and formulations based on established economic theory (Sterman 1998). Econometric and computable general equilibrium models are often coupled with energy optimization models to calculate energy prices and to determine demand (Messner and Strubegger 2001; IEA 2004). Finally, causal-descriptive models provide information on the functionality of systems to analyze the wider impacts of policies being tested (Sterman 2000).

A few very valuable studies have focused on qualitative and quantitative aspects of unconventional fossil fuel production (Utah Heavy Oil Program 2007, Bartis et al. 2005, Brandt 2008, and BLM 2008) one of particular relevance to this study, (NSURM 2006, Biglarbirgi 2007) presents a computer simulation model, the National Strategic Unconventional Resources Model (NSURM), that was developed to support the Task Force mandated by Congress as part of the Energy Policy Act of 2005 (DOE 2005) NSURM presents an aggregated picture of the potential development of the unconventional fossil fuels industry in the U.S. More specifically, NSURM is an optimization model that determines the potential production, reserves, economic statistics, and national benefits of the resources modeled at a project level. In other words, the model identifies the most economically viable recovery technology based on the geological characteristics of the area analyzed and carries out a standard cash flow analysis for every unconventional fossil fuel development project analyzed. Results from the different projects are then aggregated to calculate the potential benefits resulting from unconventional fossil fuel production, including direct federal and state revenues, as well as broader GDP benefit (mostly resulting from the domestic production of otherwise imported oil). NSURM allows for the simulation of scenarios on oil prices, desired rate of return, production and investment tax credits and adopted depreciation schedule, among others.

NSURM includes an economic component in its optimization engine, effectively presenting a partial equilibrium analysis. However, NSURM, as well as conventional optimization models, presents a static and narrowly defined picture of the unconventional fossil fuel business, using economic profitability, and the choice of the most economical technology, as the main drivers of the industry's development. Recent reports (see Utah Heavy Oil Program 2007, BLM 2008) highlight the importance of other factors for the success of the unconventional fossil fuel business, such as the availability and cost of the basic inputs to production (e.g. energy and water), and potential new regulation of emissions (US Congress, 2009). Furthermore, local policy makers have to evaluate carefully the social and demographic impact of the large-scale development of unconventional fossil fuel production, as stated in a recent comprehensive report from the Bureau of Land Management (BLM 2008).

In order to provide a complete integrated assessment of multiple interacting sectors and to enable sensitivity analysis of fuel production rates to a variety of factors, we have developed a model that takes into account the most important sectors directly and indirectly involved in the oil shale industry development through an integrated modeling approach. *ReIMAE* is neither a correlational model (Sterman 1988) nor an optimization model; rather, it is a causal–descriptive model that identifies casual relations and describes the structure and functionality of a system. The model goes beyond the analysis of inputs and outputs and includes in depth details of the structure of the energy and complexities of the many interrelated facets of the fuel production system.

Regional Integrated Assessment Model for Energy Development: ReIAME

Overview

The general goal of the *ReIAME* model is to investigate both sectoral and broader implications of unconventional fossil fuel production, with this study's specific emphasis on oil shale (OS) development in Western Colorado (and some extension analysis to the entire Green River Formation resource in Colorado, Utah, and Wyoming). The impacts range from environmental (e.g. water quantity and quality, land use, GHG emissions) to socioeconomic (e.g. jobs creation, contribution to GDP, state and federal revenues). Addressing the need to estimate the broader impacts, our model integrates the key sectors directly and indirectly involved in an unconventional fossil fuel production.

ReIMAE integrates the critical sectors involved in the energy development (Figure 2). The central sector represents the unconventional fossil-fuel production process and is connected with several important sector modules. The Energy sector accounts for electricity supplies from different energy sources and energy demands for the OS fuel production and other economic sectors. The Water sector accounts for the water supplies and demand from the sectors including the energy sector. The Economic sector, where capital investments and costs are calculated, the Population sector, and the Fuel Production sector drive the model's dynamical behavior.

Each colored box in Figure 3 corresponds to a specific sector (oil shale production process, water, energy etc.) and the lines represent the relationships among these sectors. For each box, there is another layer of detailed computer code to represent the processes within that sector. For example, Figure 4 shows a part of the code included in the Oil Shell Production Process module. ReIMAE's modularity is based on a Java–based, object–oriented modeling approach. Each sector corresponds to a Java class and the colored boxes in the main framework (Figure 3) are instances of these java classes. This modularity streamlines the process of model development and simulation analysis . In addition, *ReIMAE* can be easily customized for different applications (e.g. different retort or conversion processes, different energy sources, or different economic constraints).

ReIMAE is based on a system dynamics methodology, which solves numerically systems of integral differential equations (described in Appendix). The in situ oil production process is approximated with a discrete event simulation approach that utilizes events, conveyors, queues, and entities to simulate the dynamics of the drilling, heating, retorting, and reclamation processes. The basin is discretized into fuel production cells (entities). Within each cell, the model advances from drilling to heating once the drilling is completed (event), and then on to production and reclamation. Supporting these discrete events, electricity generation, water treatment, economics and labor are simulated using system dynamics (integral differential equation).

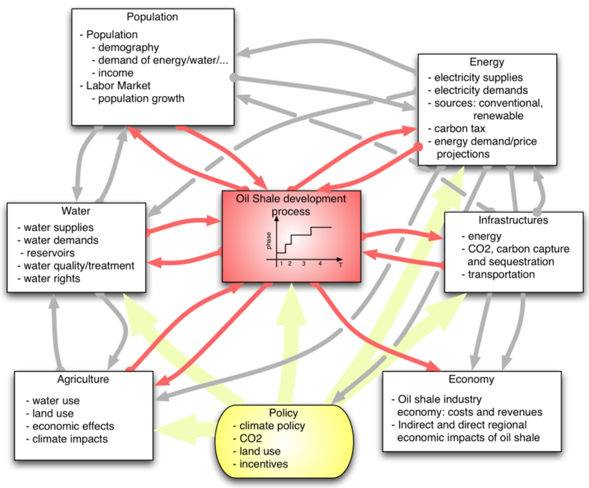

Figure 2 Schematic representation of *ReIMAE* applied to oil shale. The purpose of the model is to investigate both sectoral and broader implications of unconventional fossil fuel production. These consequences range from environmental (e.g. water quality, land use, GHG emissions) to socioeconomic (e.g. jobs creation, contribution to GDP, state and federal revenues). The *ReIMAE* integrates the key sectors directly and indirectly involved in the oil shale production. The Figure shows the most important sectors and schematically illustrates the interrelations among them.

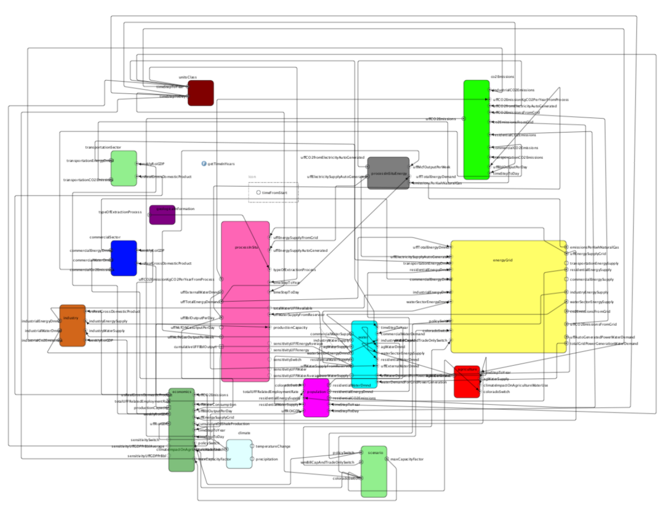

Figure 3 *ReIAME* main view. Each colored box corresponds to a specific sector (oil shale production process, water sector, energy sector, etc.) and the lines represent the relationships among these sectors. Each box represents the code that models the sector related to that box.

ReIAME is a modular model that enables application for a variety of objectives such as estimating fuel production capacity with specified constraints or estimating additional water storage capacity to support a projected fuel production rate. Here, following the development of the modeling capability, we have used the model to examine energy requirements, water demand, and green house gas generation for alternative electricity supply schemes, three sectors that are strongly related. For example, the production of energy requires large volumes of water, while the treatment and distribution of water is equally dependent upon readily available, low–cost energy. Economy and population are also key drivers of the energy sector, characteristics that are common in all energy development systems. The model structure (Figure 2 and Figure 3) can be used to describe the production of any type of energy from oil shale and tar sand to nuclear and biofuel. What renders the model specific to a particular energy is the fuel production process module (central red box in Figure 3). The model framework and the individual modules that are not directly related to a specific fuel production process do not need to be changed because the fuel (energy) production process module is independent.

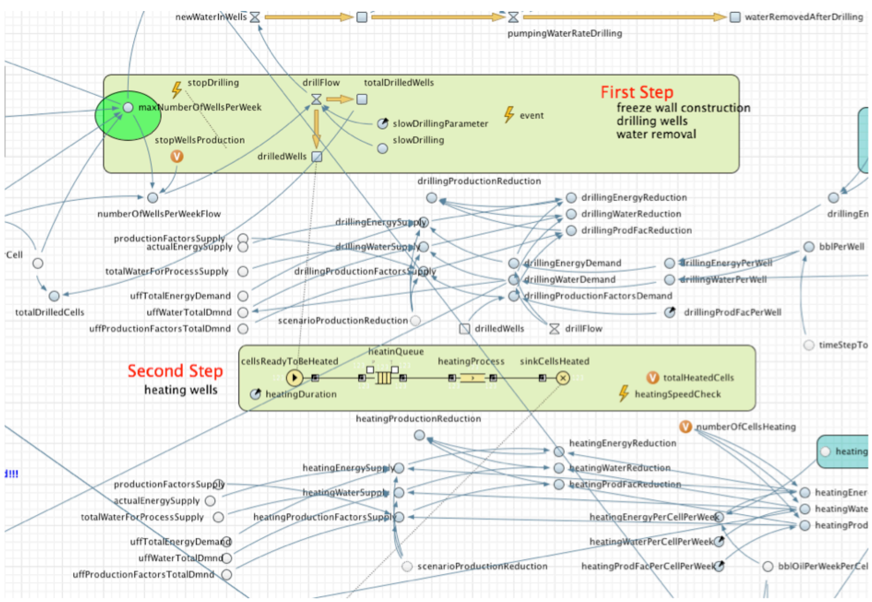

Figure 4 The figure shows part of the code included in the *OS Production* module: The small circles are variables and parameters, the arrows and squares represents differential equations, and the lines between two variables are mathematical relations between these variables The *ReIAME* model consists of 13 modules summarized in Table 1 and described in detail in Appendix.

ReIAME consists of 13 modules:

1. Oil Shale Production Process module, which models all of the phases of a specific production process

2. Oil Shale Energy module, which models electricity generation

4. Oil Shale and Regional Economic module, which models the economics of the oil shale industry (e.g. capital investments, operating costs, labor costs, etc.), as well as the regional economic impacts

5. Population and Residential module, which models the population dynamics for both regional and the oil shale industry contribution, accounting also for residential water and electricity demand

6. Energy module, which models energy production and supply to all sectors excluding the oil shale production sector.

7. Water module, which models the water demands and supplies for all economic sectors

8. Agriculture module, which models the agriculture sector energy and water demand as well as its CO_2 emissions

9. Commercial module, which models the commercial sector energy and water demand as well as its CO_2 emissions

10. Industrial module, which models the industrial sector energy and water demand as well as its CO_2 emissions

11. Transportation module, which models the transportation sector energy and water demand as well as its CO_2 emissions

12. CO_2 Emissions module, which calculates and represents the emissions generated in the analyzed region by the oil shale industry activity as well as by energy consumption in all economic sectors

13. CO_2 Management module, which models the carbon dioxide capture and sequestration deployed by the oil shale industry

Oil Shale Production: Shell In-Situ Oil Shale Conversion Process

There are multiple concepts on how to produce oil in situ from the rich, deep oil shale reserves of Western Colorado. Here, we focus only on the Shell In-Situ Conversion Process (Shell ICP) in order to demonstrate the *ReIAME* methodology. The Shell ICP has been reported and analyzed somewhat more extensively than other, emerging concepts from such companies as ExxonMobil, Chevron, and American Shale Oil Company. Recently, an Idaho National Laboratory (INL) team summarized the Shell ICP methodology, history, and operations (INL, 2010). In their summary, INL highlights the process, which includes four phases (1) drilling and freezing, (2) heating, (3) hydrocarbon recovery or production, and (4) reclamation. The processes have been reported by Shell (2006, 2010a, 2010b) and analyzed by external researchers (e.g. Brandt, 2008 and Bartis and James, 2005). They are described in the next section in the context of how the phases are modeled.

ReIAME Structure for the Shell ICP

The heart of the integrated assessment model is the *Oil Shale Production Process* module, which simulates the specific phases of fuel production. This module reflects the specific production process technique analyzed. For the application presented in this chapter, *ReIAME* simulates the Shell ICP (DOE OST 2007, Shell 2006). The first phase of the process entails excluding groundwater flow from the oil production zone (known as pyrolyzed area) with a freeze wall, installed around the area before production starts. This freeze wall consists of a series of wells drilled outside the heated area, where a fluid at –45 Fahrenheit is circulated through a piping system, freezing the rock and ground water around the perimeter of the containment area. After the freeze wall is installed, the containment area is dewatered to remove ground water prior to heating, allowing recovery of the hydrocarbon products. Then, the oil shale zones within the geological formation are electrically heated. The high temperature heating process pyrolyzes the organic matter in the oil shale and converts it into liquid hydrocarbons and combustible gas. The high temperature (550 to 750°F (DOE OST 2007, Curtright et al. 2008)) cracks the kerogen into smaller hydrocarbon molecules that are slowly upgraded by in situ hydrogenation. The heating process takes several years to reach these high temperatures (2 to 4 years (Shell 2006, Curtright et al. 2008)). The pyrolysis product is then pumped from the ground and is characterized as a mixture of water (known as pyrolysis water) , hydrocarbons, and natural gas. This mixture is separated via a cleaning process that also removes impurities. After withdrawal of the recoverable product, the formation inside the freeze wall is flushed with several pore volumes of water to clean the residual pyrolysis products. Wong et al. (2007) provide figures showing the geometric relationships between the wells, freeze wall, heaters, and geologic formations. Brandt (2008) provides a figure showing the size of a 'cell', defined by the freeze well configuration and the zone targeted for pyrolysis.

In *ReIAME*, the production area is divided into a grid of production cells, and each cell contains multiple wells. The development of each cell consists of four phases that approximately describe the ICP process, as shown in Figure 5:

1. Drilling phase: includes drilling for freezing establishing the freeze wall, dewatering and drilling the producer wells

2. Heating phase: heating the rocks through electric heaters

3. Retorting phase: pumping out the recovered product

4. Reclamation phase: flushing the pyrolyzed area

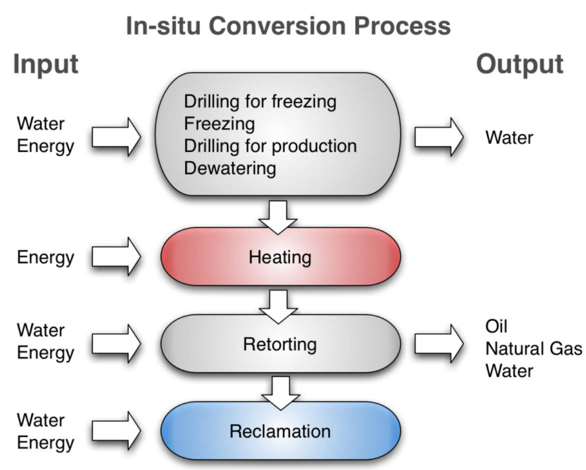

Figure 5 Shell In–situ Conversion Process (ICP) as modeled with *ReIAME*

In this process cells are developed sequentially and activities in the model advance to next cell with completion of activities in previous cell (i.e. drilling is a continuous process). In other words, once the drilling phase of the first cell is completed, the heating phase on the first cell starts and at the same time the second cell's drilling phase begins, and so on. Each phase is characterized by specific duration, energy, and water needs. The heating phase is the most energy intensive phase, whereas the reclamation phase requires most of the total water demand. The main outputs of the *Oil Shale Production Process* are the production process demands for energy and water in time for each phase. The pyrolysis water obtained during the retorting process is reused in the process. One third of the pyrolysis product from the retorting phase is natural gas (Bartis et al. 2005, Utah Heavy Oil Program 2007, NSURM 2006) which is used in the model for generation of electricity through a natural gas-fired power plant (NGCC) (Brandt 2008).

Fuel production capacity, and energy and water availability drive the production process and are inputs for the *Oil Shale Production Process* module. These inputs are calculated in the *OS and Regional Economics, OS Energy, and Energy Sector* modules for produced electricity, and *Water Sector* modules respectively. *ReIAME* estimates the water needed to generate the electricity required for oil recovery (*OS Energy* and *Energy Sector* modules) and the oil shale industry CO_2 emissions, principally due to electricity generation (*CO_2 Emissions* module). Oil production drives new employment and, as a consequence, the fuel development contribution to the population as well as to the regional GDP. *ReIAME* considers employment for construction, for maintenance, and operating the industry (direct employment) as well as the indirect employment. The model allows for a partial equilibrium, macro analysis of the production requirements and economics of fuel production, and for the analysis of social, economic and environmental impacts at local, state and federal level. Construction, operating, and maintenance (O&M) costs of oil shale production are evaluated in the *OS and Regional Economic* module. O&M costs include water, energy and labor, as well the price of CO_2 management in a scenario with climate policy enactment. Energy and water demand, as well as CO_2 emissions, are calculated for the agriculture, commercial, industrial, residential and transportation sectors as well. Appendix describes in detail each of the *ReIAME* modules and the interrelations among them.

ReIAME and Oil Shale.

The potential development of oil shale resources faces a number of questions regarding the costs, energy inputs, greenhouse gas emissions, and potential impacts on land and water resources. According to the U.S. Geological Survey (USGS 2009), the U.S. oil shale resource reaches more than 1.5 trillion barrels of oil, and most of this resource is present in the Green River formation, a North America region that covers parts of Colorado, Utah, and Wyoming. The ICP production process, modeled for the present work, is technically feasible in deep deposits like the deposits in this studied area. This is also the geographical area where the industry is operating its early pilot projects and testing different production methods (Shell 2006). Being this region the area that most probably would be impacted by the exploitation of oil shale reserves, we focus our study on this whole area.

The baseline scenario simulates a large-scale oil production with a target of 1.5 Mbbl/day[1] over a 30-year period (see). 1.5 Mbbl/day as the desired maximum production value is consistent with the values reported in most published studies (SPE 2007) allowing us to validate our results against the results obtained in these other works. We assume that the production begins in 2009 and reaches the desired target by 2040 following a ramp up shown in Figure 6 estimated using the INTEK's production

[1] We use the notation 1 Mbbl = 1 million barrel of oil;

1 bbl = 42 U.S. Gallons of oil

ramp up (SPE 2007, NSURM 2006). To put these numbers into perspective, the development of this oil shale industry would supply about 11 percent of the total national petroleum consumption in 2040 projected by EIA (AEO 2009).

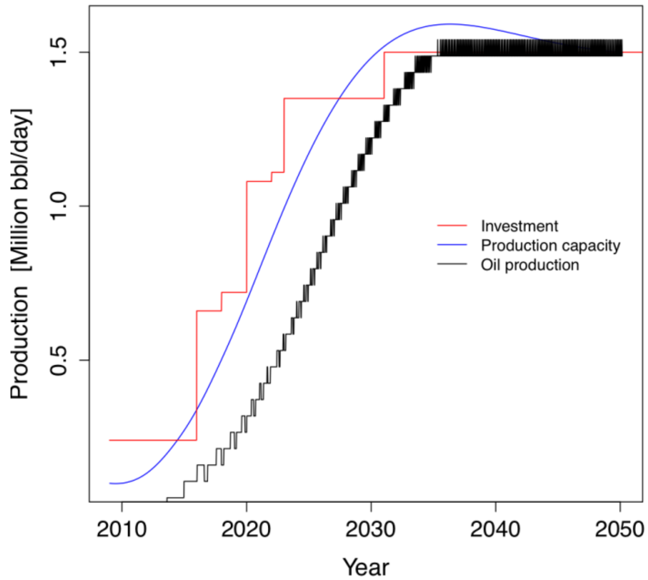

Figure 6 Investment, production capacity, and oil production: The red line shows the assumed investment ramp up, expressed in terms of cumulative investments, based on NSURM (2006) estimates. The blue line represents the actual cumulative production capacity, whose shape reflects the model's accounting for a 5-year lag time for construction. We assume that production capacity (blue line) will become available on a continuous basis. This is due to the facts that (1) a 1.5 Mbbl/day production level will likely involve a wide variety of companies and contractors, each of them having different plans and deadlines, and (2) the recovery of oil from shale consists of various steps, each with a specific timing and duration (e.g. drilling can start even if the infrastructure for heating is not entirely available and different areas can be worked in parallel or sequentially). The black line represents actual output (oil recovery from oil shale). for the time required for drilling, heating, and recovery is responsible for the lag between the production capacity and actual production of oil.

Table 1 *ReIAME* modules.

Modules Name	Contents
OS Production Process	Oil Shale (OS) production process
OS Energy	Electricity on–site generated by the OS industry
OS Water	OS water management: water reservoir size optimization
OS and Regional Economics	Economics of the oil shale industry and contributions to GDP,
	Federal and State revenues. Direct and indirect employment
Power Sector	Electricity demand from the oil shale industry and from all economic sectors considered in the study. Electricity supply from the grid, following the energy mix of the analyzed area
Water Sector	Water demand from the oil shale industry and from all economic sectors considered in the study. Water supply from rivers and basins of the analyzed area
Agriculture Sector	Energy and water demand; carbon emissions
Commercial Sector	Energy and water demand; carbon emissions
Industrial Sector	Energy and water demand; carbon emissions
Population and Residential Sector	Energy and water demand; carbon emissions Population growth Ð population and residential sector
Transportation Sector	Energy and water demand; carbon emissions
CO_2 Emissions	Carbon dioxide emissions from oil shale production and all other economic sectors considered in the study
CO_2 Management	Carbon dioxide capture and sequestration by the OS industry
Scenario	Set a specific scenario
Parameters	Set specific parameter related to specific scenarios

Analysis

In this Analysis section, *ReIAME* is exercised to examine aspects of the oil production process. As described previously, the methodology for in situ conversion considered follows an approximation of the Shell In Situ Conversion Process because of the level of reporting and information that has become publically available. This does not imply any expectation that the Shell ICP will be the dominant methodology for oil production; rather, it is a mechanism for demonstrating the integrated model, which is modular and amenable to substitution of alternative technologies, processes and schedules for comparative simulations. In the scenarios described next, the phases for oil production include, drilling and freezing, heating, production, and then restoration. Electricity and water requirements are evaluated through each of the phases as cell after cell are developed and then remediated during basin-wide fuel production.

Scenario Definitions

Electricity and water requirements are the primary focus of the scenarios investigated in this demonstration of ReIMAE. The scenarios defined here allow for simulations of alternative fuel production levels supported with different power production alternatives (e.g. natural gas, coal, and renewables). The simulations, approximating a basin-wide Shell ICP methodology, investigate the sensitivity of water requirements and CO_2 generation to the different potential scenarios for providing power and to the associated assumptions. Economic implications are also highlighted with respect to tradeoffs related to potential different business model choices.

We analyze four scenarios, each characterized by a different energy mix used to generate the electricity for potential oil shale industry growth. In the scenarios, we consider involve different combinations of fuel used to power the electricity demand of the four stages of fuel production and restoration. In all cases, natural gas produced during in situ conversion of oil shale is used to its fullest extent (up to almost 50% of electrical power demand at full production). All additional power is provided in these simulations through a combination of additional natural gas, coal, and/or renewables.

The scenarios considered here are defined as follows and shown in Figure 7.

- S0 scenario (Base Case): The mix of electricity production to supply the situ oil shale development process is a mix identified by Brandt (2008). Natural Gas Combined Cycle (NGCC) power plant(s) using natural gas produced during in situ production and meets 46% of the electricity demand at full operating capacity with 55.8% efficiency (Rubin et al. 2005). This NGCC component of the power ramps up from zero at the beginning when power is required, but natural gas derived from ICP has not become available. The remaining demand, reducing from 100% at the beginning to 54% at full operating capacity, is produced with an assumed energy mix of 72% coal (supercritical pulverized bituminous coal plant (PC)), 24% natural gas (NGCC), and 4% renewable energy (Brandt 2009).

- S1 scenario: All of the electricity to meet demand is produced by NGCC power plant(s). All natural gas not derived from the oil shale ICP is developed from other extraction (this part of the USA is a major natural gas producing region)

- S2 scenario: A maximum of 46% of the total electricity demand is generated using natural gas from the oil shale ICP; the remaining demand starts at 100%, decreases to 54%, and is based entirely on coal with an IGCC power plant. Note, this scenario differs from S0 in the coal power process and because no additional natural gas or renewable power production is used.

- S3 scenario: A maximum of 46% of the total electricity demand is generated using natural gas from the oil shale ICP; the remaining demand starts at 100% and decreases to 54%. 25% of the remaining demand is met using wind-based renewable power and the 75% of the remaining is generated using coal through an IGCC power plant.

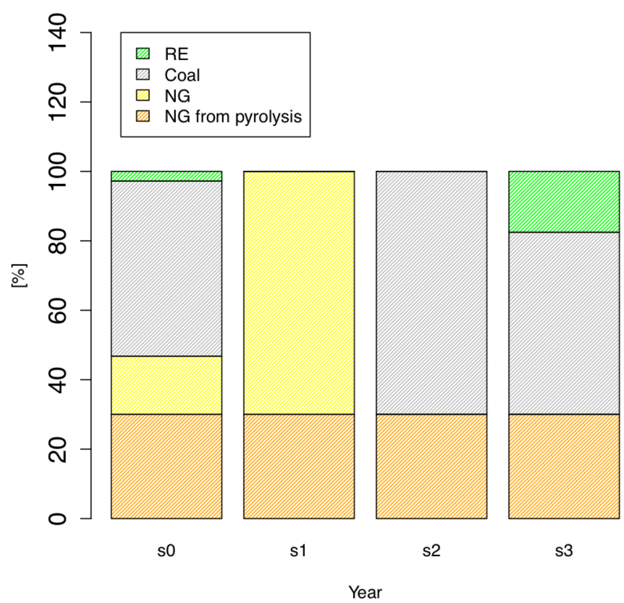

Figure 7 Energy scenarios: Each scenario is characterized by a different mix of energy sources used to generate the electricity required by the oil shale industry development.

For each of these scenarios, carbon dioxide capture and sequestration deployment, water requirements, and the cost implications of the enactment of a climate change policy (i.e. cap and trade mechanism) are examined in the following subsections.

For each energy mix scenario, *ReIAME* is executed to track the phases of site development and fuel production over the life cycle of basin-wide production. These demonstrations serve to highlight the process for evaluating alternative combinations. In these cases, alternative power production combinations are considered; the modular framework is designed to allow for other alternatives, such as ICP methods, carbon capture methods, and so on. Here, only one technology for in situ conversion is considered, but the model is designed to incorporate readily other techniques with different scheduling, energy requirements, and so on. The simulation results are organized in the next subsections to highlight the production process, the environmental impacts, and then the socioeconomic impacts.

The scenarios are hypothetical and these results are only demonstrative of the simulation process. The timeline in the scenarios is assumed it commence in 2004 and, hence, does not map to ongoing activities (which have not yet begun). The timeline for production is approximately 50 years and this approach dissuades guessing when political, economic, and policy constraints might align to allow for a favorable commencement of this scale of production.

Oil Production

The simulated production ramp up for oil shale operations (red line in Figure 8) follows projections from NSURM (2006) increasing in this study to a maximum capacity for the region of 1.5 Mbbl/day. We assume investments that enable production capacity to be allocated in steps, at various times and of different amounts. This resembles the early phases of development of a growing industry, when a variety of competitors enter the market, before a consolidation phase. While the first investments start, hypothetically, in 2004, other investments are assumed to take place in 2007, to start producing in 2015. Further investments are projected for 2012, 2014 and 2016, as well as 2019 and 2027, which is when the total cumulative investment of the industry allows reaching 1.5 Mbbl/day of output by 2035.

The actual infrastructure construction needed to produce oil from shale (blue line in Figure 8), driven by the investment mentioned above, gradually increases over time to reach a maximum of about 0.5 Mbbl/day of production capacity under construction in 2022. A 5-year construction delay is built into the model to represent the completion rate (and availability) of production capacity. Furthermore, a capital lifetime of 30 years is considered to calculate the discard of aging infrastructure. The replacement of capital requires the construction of new production capacity, which, over the longer term (steady state), requires having about 0.5 Mbbl/day of capacity under construction (NSURM 2006).

When comparing the simulated production capacity to the investment in infrastructure in Figure 9, the 5-year delay in construction is evident. Milestones in installed capital for production levels of 0.1, 0.5, 1, 1.5 Mbbl/day are reached in 2010, 2018, 2026, 2035 respectively with the schedule imposed here. The projection of production capacity (blue line) is smooth with respect to the investment (red line) because we assume that (1) the investment is put in place by a number of different participants, (2) construction plans are characterized by different timing and delays, and (3) drilling and heating can start even if the infrastructure for recovery and remediation are not yet in place (it is assumed that the heating phase takes 3 years alone). A pipeline delay for representing the development of production capacity is not used in these simulations; it is assumed to be developed during other infrastructure development.

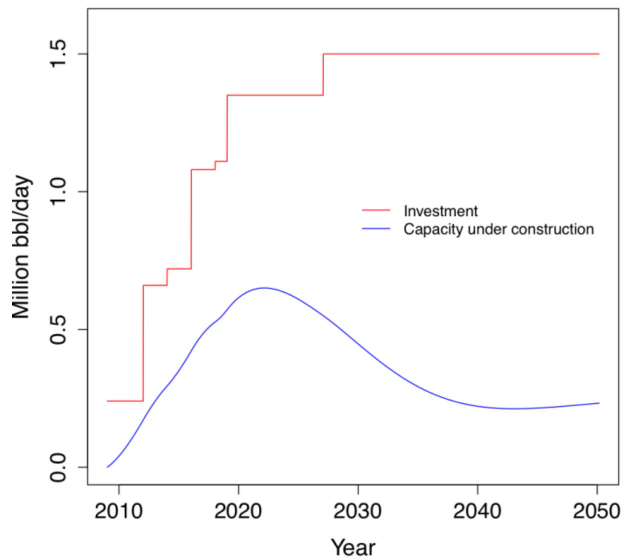

Figure 8 Planned production capacity (investment, red) and production capacity (blue).

Figure 9 compares the timing of oil output to rates of investment and infrastructure development adding a few new dimensions to investment and production capacity analysis. The delay on production is primarily due to the duration of the four main production phases (drilling, heating, recovery and reclamation). The heating and recovery phases require about 8 years (5 for building infrastructure and 3 to complete drilling and heating) to produce oil from the time that the investment is put into place and the construction of facilities starts. Specifically, the recovery of oil from shale is simulated to start at the beginning of the fourth year after the infrastructure is in place. In addition, the projection of oil output shows small weekly variations and is not as smooth as production capacity. This is because every cell being heated and produced is represented and tracked in the model, as well as the timing necessary to complete the production phases associated with each cell. In other words, oil production is not averaged throughout the basin under development; rather the drilling of wells, heating, recovery and reclamation is tracked for each cell. Milestones in production levels of 0, 0.5, 1, 1.5 Mbbl/day are reached in 2015, 2022, 2028, and 2035 respectively.

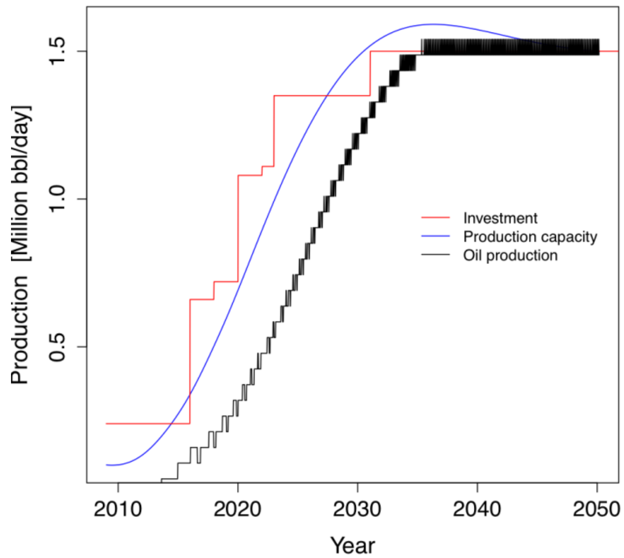

Figure 9 Planned production capacity (investment, red) , available production capacity (blue), and oil production (black). Investment, available production capacity, and oil production are presented In terms of oil production rate (Mbbl/day)

Environmental Impacts

Water

Water requirements for shale-oil production are considered for each of the four phases as well as for cooling power plants supplying the required energy. Of the four phases, reclamation accounts for over 90% of water consumption per barrel produced at full operating capacity (Figure 10), not counting the water for the power plants. Water demand is disaggregated by phase to highlight that drilling, heating and retorting are not water intensive when compared to reclamation, even at full operating capacity. Because reclamation begins after a cell has been fully produced, these simulations show that water demand lags behind oil production and continues after production ceases. In these simulations, water produced during the production process is treated and utilized. This includes both the water produced during the drilling phase and the water obtained as pyrolysis product during the recovery phase. The total equals 3,200 gallons per year at full operating capacity that corresponds to 14% of the total direct water demand (for the four phases, not cooling of power plants).

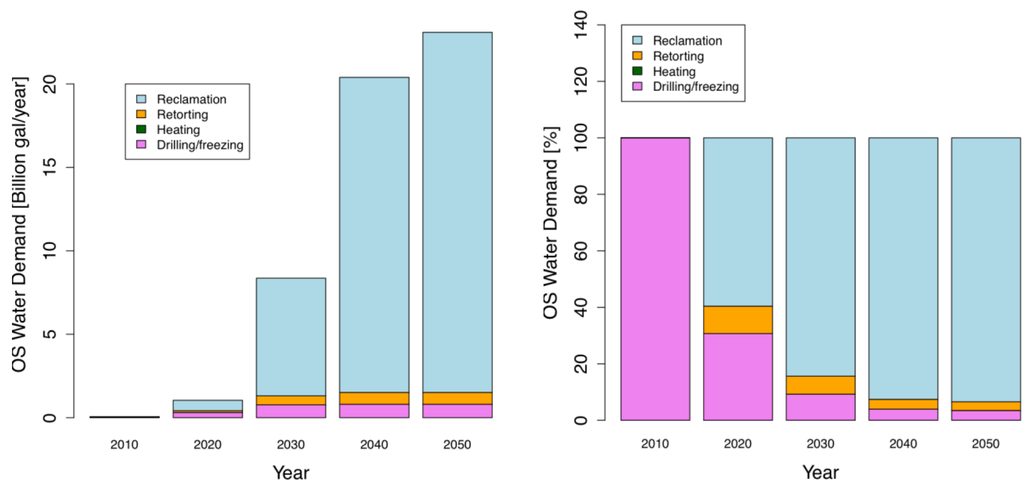

Figure 10 Left: Direct OS water demand from each production phase for selected years. The heating phase requires no direct water. Figure does not include water for power generation. Right: Water demand of each production phase expressed in percentage. Figure does not include water for power generation

The projection of water demand per unit of oil produced compared with the water demand for power generation is shown in Figure 11. The most energy intensive production phase, heating, takes place before the recovery of oil in any cell. Process related water consumption per barrel of oil produced starts at about 13 gallon/bbl in 2012, when water is only used in the drilling and recovery phases. However, when the reclamation phase for the first cells starts in 2015, simulated water demand grows, but not continuously (due to non-continuous demands for the different phases), eventually reaching 42 gallons/bbl as reclamation demand reaches a steady state. For example, between 2015 and 2018, water demand per barrel produced decreases due to increase in output from the second investment. While, this process continues as more and more cells are being produced and advance to the reclamation phase, the weekly variations get smaller as the installed base and output increase. Water demand reaches 42 gallons/bbl when production reaches 1.5 Mbbl/day.

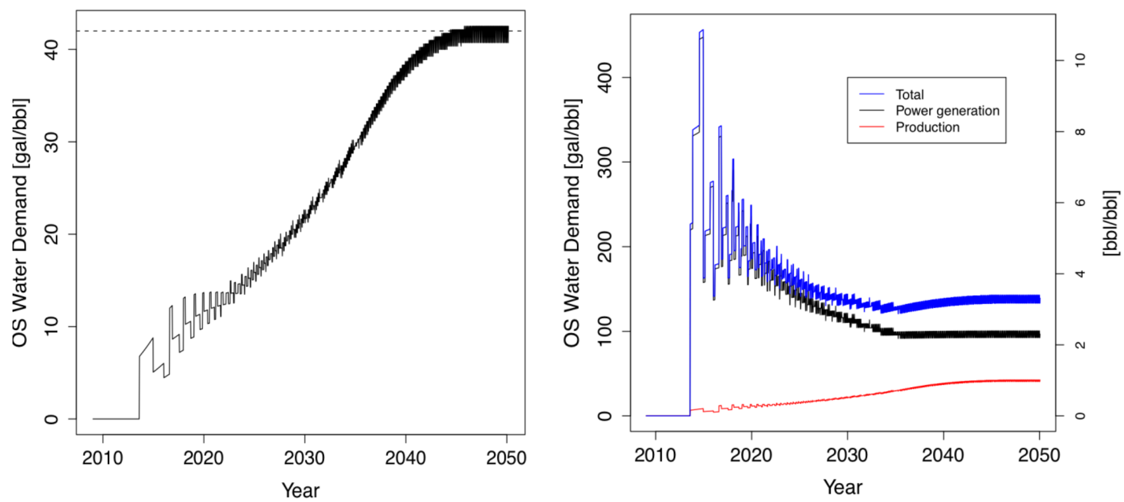

Figure 11 Left: Oil shale water demand (gallons per barrel of oil produced) for ICP production process; in this plot we do not account for the water that can be recovered and used during the production. The dashed line corresponds to 1bbl, 42 gallons. Right: Total water demand per barrel of oil produced (blue) includes water for process (red) and to generate the requested power (black). In this plot we account for the water that can be recovered and used during the production process

Total water demand for power production and ICP in 2040, accounting for the water that can be recovered and used during the production process is about 190 Million gallons per day (Figure 12). At full operating capacity, most of the water (71%) is needed to generate power and only 29% is required for production (mostly reclamation) of which 15% is recovered. For the base scenario (S0), of the water consumed to generate electricity, 47% is needed for the natural gas power production and the remainder is used for electricity generation from other sources (see Figure 14).

Figure 12 compares the total water demands for the alternative scenarios, where the power is generated by different energy mixes and CO_2 capture is not considered. Different energy generation technologies have different water consumption factors, which result in different water requirements. Of the scenarios considered, S1, with all power coming from natural gas (NGCC), has the lowest water demand (about 20% lower than the base case scenario), followed by S3 (14% less), in which a combination of natural gas, coal, and wind is used. Scenario S2 uses only 5% less water than S0; although more coal is used in S2 than in S0, the IGCC process yields efficiencies in water consumption.

Figure 14 compares water demand for power requirements of the oil shale sector (case S0, Shell ICP approximation model) with the total water demand for power generation in the region of interest excluding the oil shale contribution. As simulated, oil shale development will increase water for power demand in the region, reaching a maximum of 143 Million gallons/day relative to the 11 Million gallons/day required for the regional (excluding oil shale) power demand (Figure 15 and Figure 16). However, water demand in the studied region, even when accounting for oil shale production, is dominated by the agriculture sector with 66% of the total water demand. The impact of the simulated development of the oil shale industry in the region is that industrial water demand grows from 13% in 2009 to 24% and 28% of total water demand in 2020 and 2040 respectively.

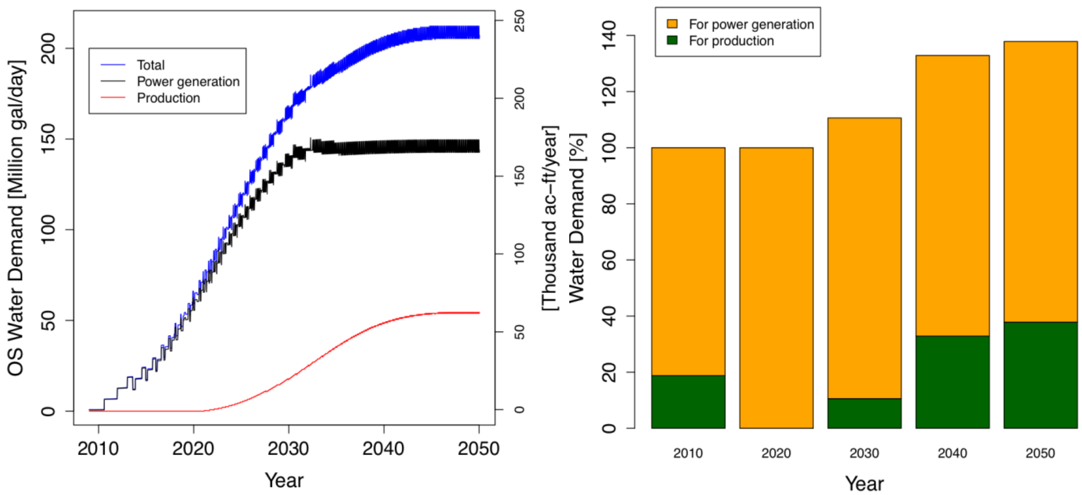

Figure 12 Left: Oil shale water demand: water needed for production (red line) and water needed to generate required power (black line). Blue line shows the sum of these two contributions (total water demand). Right: Water demand expressed as percentage.

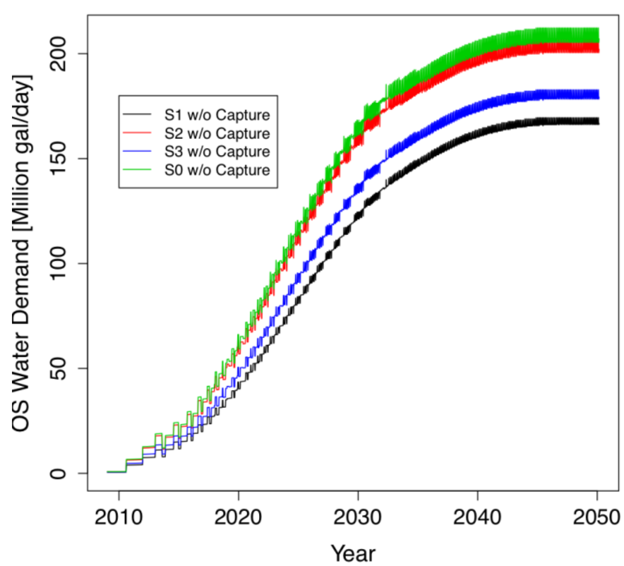

Figure 13 Oil shale water demand for different scenarios. without CO_2 capture. Power is produced in all scenarios using burning the natural gas recovered from the process (NCGG); the unmet power demand is produced by S0: Coal, NGCC, renewable; S1: NGCC; S2: IGCC; S3: wind and IGCC

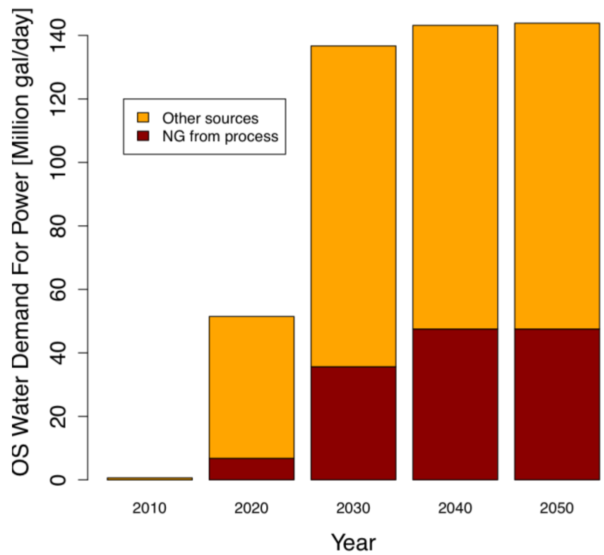

Figure 14 Oil shale water demand for power generation. One part of the power demand is met using the natural gas recovered during the production process (dark red). In the baseline scenario, the remaining power (orange) is generated by the following mix: 72% (of the remaining power) coal, 24% of natural gas, not generated during the production process, and 4% of renewable energy.

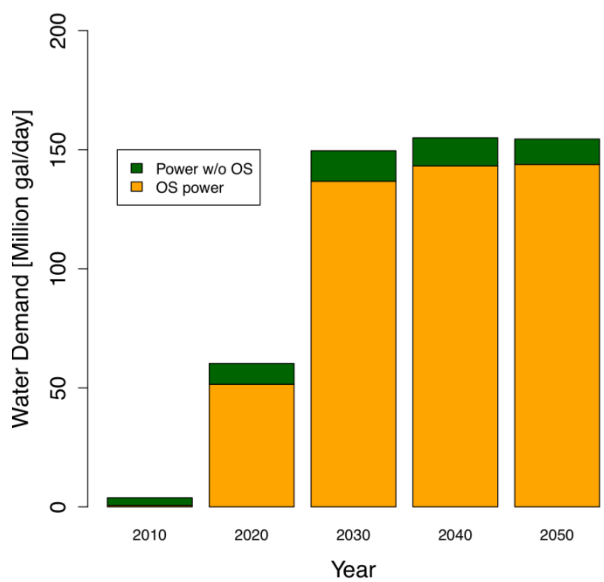

Figure 15 Oil shale water demand for power (orange) compared to the background water demand for the power sector (dark green) of the analyzed region.). The growth in the background water demand is the result of the oil shale industry impact on population and service sectors in the region.

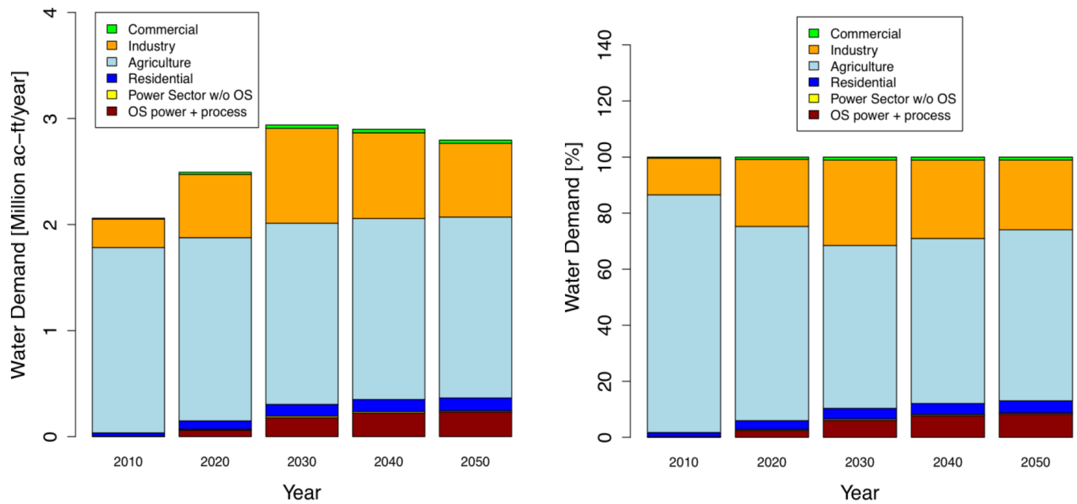

Figure 16 Left: Water demand by sectors. Right: Water demand by sectors (percentage)

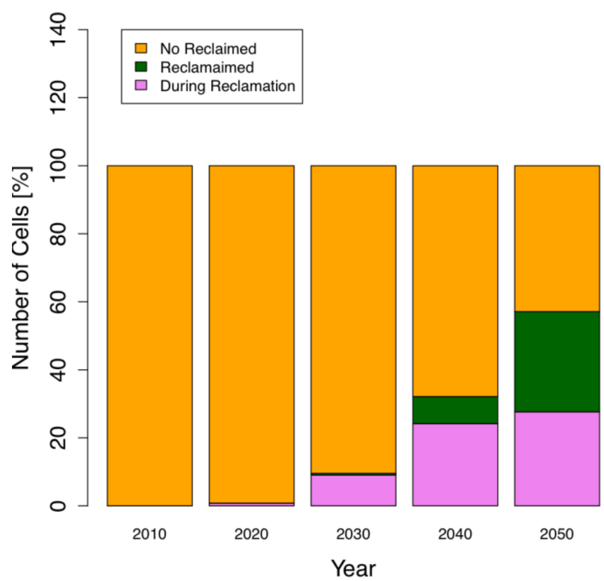

Figure 17 Number of cells not yet reclaimed (orange),), during reclamation phase (violet), and reclaimed (dark green).

The power production for the basin-wide approximate Shell ICP process considered here is almost entirely required for in situ heating (Case S0, Figure 18 and Figure 19); it increases to a steady state during development of the basin, where it stays until heating requirements decrease at the end of the basin-wide development . Energy demand *per barrel* decreases over time because most of the energy consumption in the production of oil from shale takes place in the heating phase before oil can actually be extracted. As soon as production starts, the average energy demand per barrel produced is projected to be high, reaching a value slightly higher than 1.4 MWh per barrel of oil produced. As the first investment is realized, from 2012 through 2016 in this simulation, the average electricity consumption per barrel produced decreases due to the increase in output. In that time period, drilling and heating of cells supported with the second investment start taking place resulting in an increased electricity demand per barrel produced for a short period of time and then a decrease as output increases, hence the non-smooth nature of the energy per barrel curve in Figure 19. Simulated demand of electricity per barrel produced stabilizes at about 0.35 MWh per barrel of oil produced (200 kWh per year) when the targeted production output is reached.

As production output increases, the fraction of electricity generated using the natural gas recovered during production grows (Figure 20 and Figure 21). This is due to the assumption that all of the natural gas obtained from the oil shale production activity is used for electricity generation (natural gas represents 1/3 of the total output from shale processing, with the remaining 2/3 being light oil) (Figure 21). It is also assumed that a natural gas fired turbine with an efficiency of 55.8% (Rubin et al. 2005) would be used to generate electricity, leading to about 46% of demand being satisfied by the internal use of recovered natural gas after 2040.

Net energy resulting from the production of oil from shale, commonly called Energy Return on Investment (EROI) or Energy Return on Energy Invested (EROEI), is calculated as the ratio between energy output and energy input, with energy input being the sum of all energy sources used to produce a barrel of oil and energy output being the energy content of a barrel of oil produced. For simplicity and consistency, both energy input and output are converted into BTUs to calculate this dimensionless indicator.

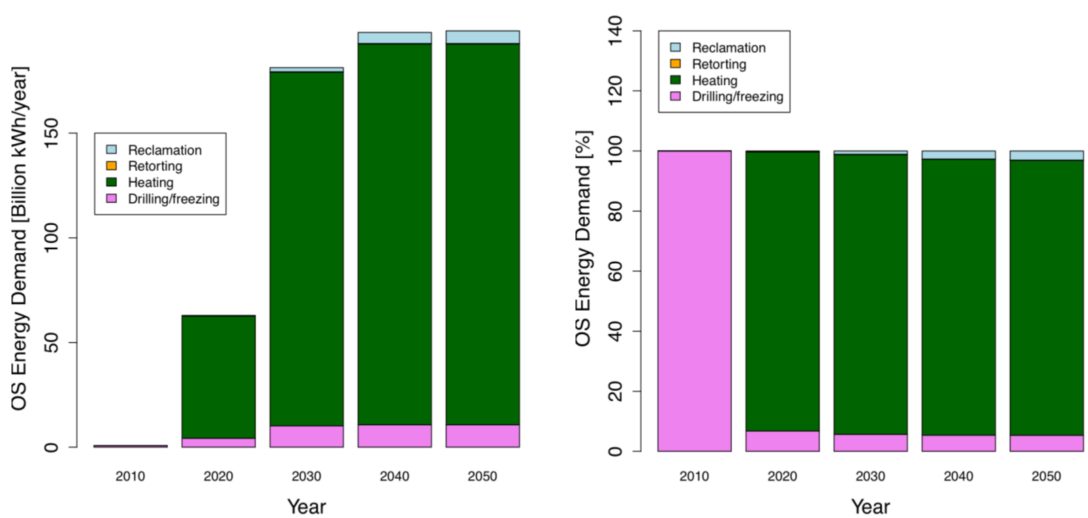

Figure 18 Left: OS energy demand of each production phase. Right: Energy demand of each production phase expressed in percentage

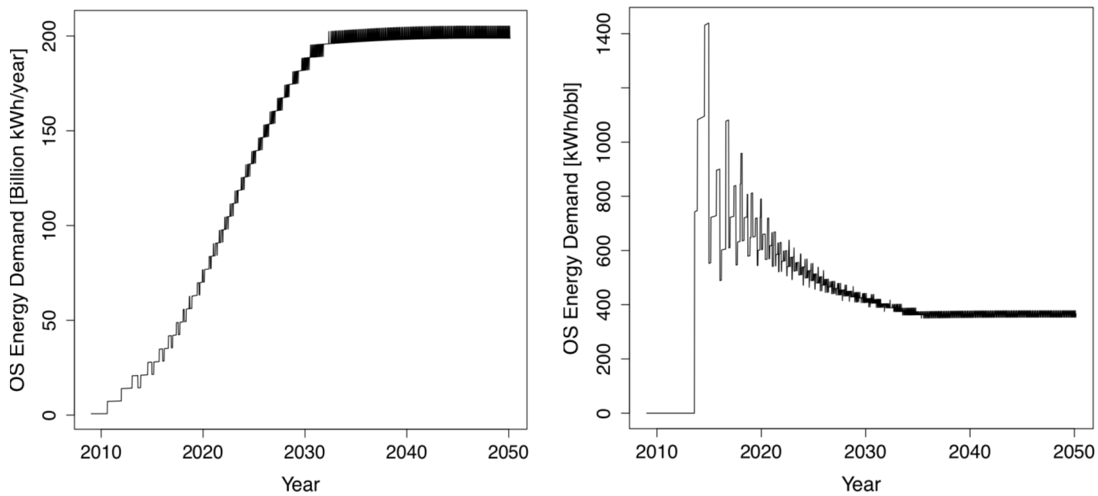

Figure 19 ***Left*****: Oil shale energy demand.** ***Right*****: Oil shale energy demand per barrel of oil produced**

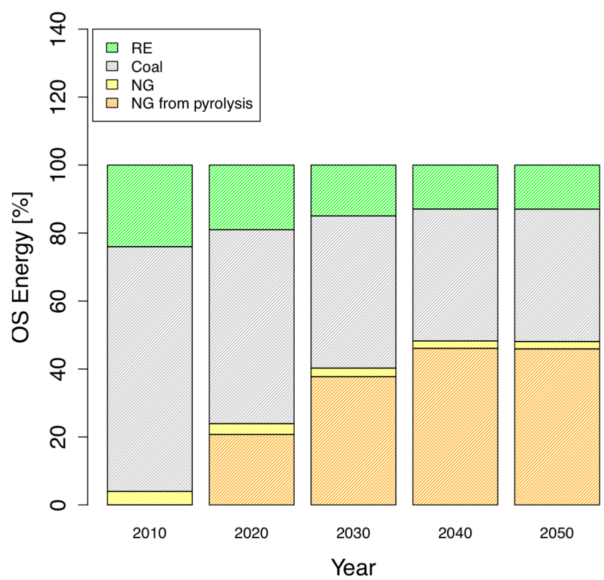

Figure 20 Baseline scenario: Oil shale energy supply by energy sources.

EROI is projected to be approximately 1 as production starts, which means that there is no gain and no loss in producing oil from shale, other than the input being electricity and the output being transportation fuel. To put this into perspective, conventional oil production currently has an EROI of 10:1, which used to be 25:1 only about 30 years ago. As production increases, and the relevance of the various phases of production decrease (i.e. with a small installed capacity and output, the heating phase has a greater impact on the EROI, generating short-term variations in the trend), the simulated energy return on investment increases to about 4:1, when the desired output is reached, similar to the range reported by Brandt (2009), DOE (DOE Energy Efficiency fact sheet), and Utah Heavy Oil Program (2007). The oil shale industry is projected to play a dominant role in the growth of electricity demand in the region (not surprising as there currently is very little energy demand in the region) and in the US (Figure 22). In these simulations, it is projected that in 2020 (16 years after the basin-wide development commences), oil shale activities will account for 76% of electricity demand in the region, a value that grows to 90% by 2040 (36 years after commencement) which equals about 10% of the U.S. electricity demand in 2008. Following the oil shale industry in energy demand are the commercial, industrial and residential sectors, also highly impacted by the growth of GDP and employment driven by the development of the oil shale business in the area (Figure 22). The baseline scenario projects an increasing penetration of natural gas as highlighted in Figure 20. The baseline scenario does not take into account state and federal policies on renewable energy standards (RES) and carbon pricing that have not been approved to date. In addition to the electricity generated with natural gas from the ICP, we assume that the share of electricity generation for the unmet demand will remain constant throughout the simulation period. As a result, for the unmet demand, coal in the baseline simulation accounts for 72% of electricity generation, followed by natural gas (24%) and non fossil fuel sources (4%).

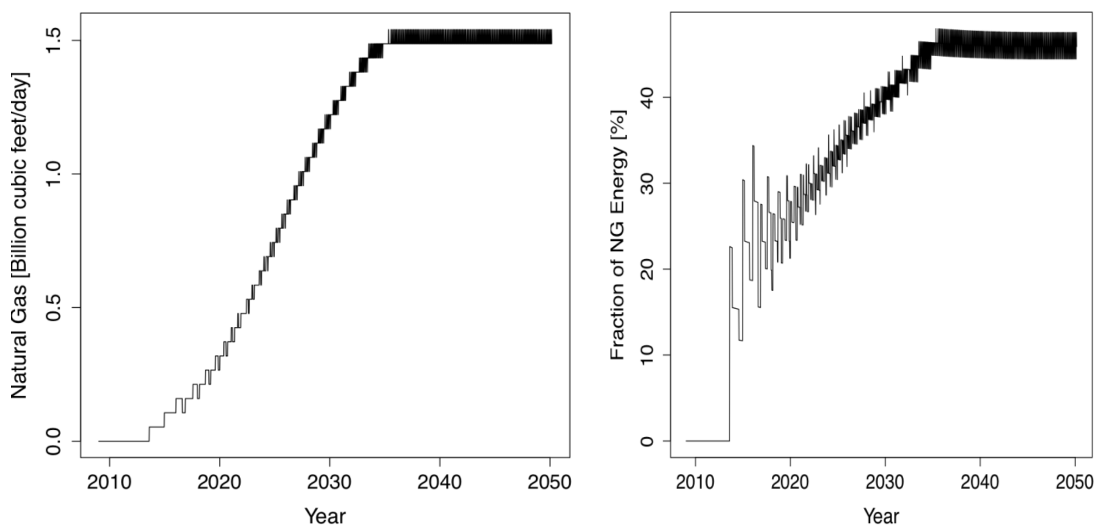

Figure 21 ***Left*****: Natural gas recovered during the production process.** ***Right*****: Fraction of electricity produced by the natural gas generated during the retorting process**

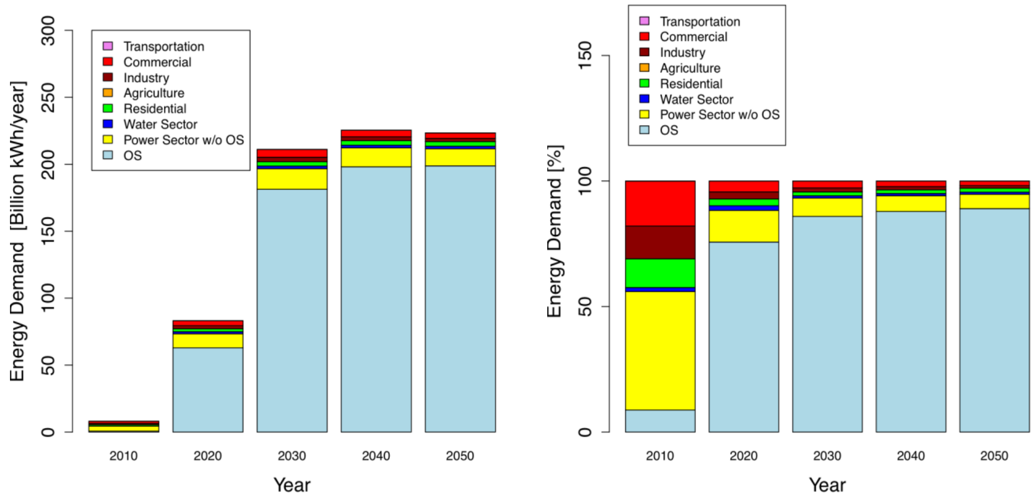

Figure 22 ***Left*****: Energy demand by sectors** ***Right*****: Energy demand by sectors (percentage)**

Carbon Dioxide Emissions

The generation of CO_2 emissions from the oil shale industry is, not surprisingly, a sizable fraction for the region (83% by 2040, see Figure 23). We project that the total amount of emissions resulting from the production of oil from shale will grow considerably over time, ranging from 0.4 Mt of CO_2 per year in 2010 to 113 Mt of CO_2 per year in 2040 (Figure 23 and Figure 24). The CO_2 emissions for the base case are mainly due to electricity generation (84%) and the remaining emissions (16%) are generated from cleaning the natural gas recovered during pyrolysis to produce a useable natural gas stream. Oil shale production is projected to generate about 0.2 tonnes of CO_2 per barrel of oil produced when the desired production level of 1.5 Mbbl/day is reached (Figure 25). The projection of emissions per barrel follows that of energy consumption per unit produced, decreasing over time as the output increases. Short-term variations are due to the high energy intensity of the heating phase.

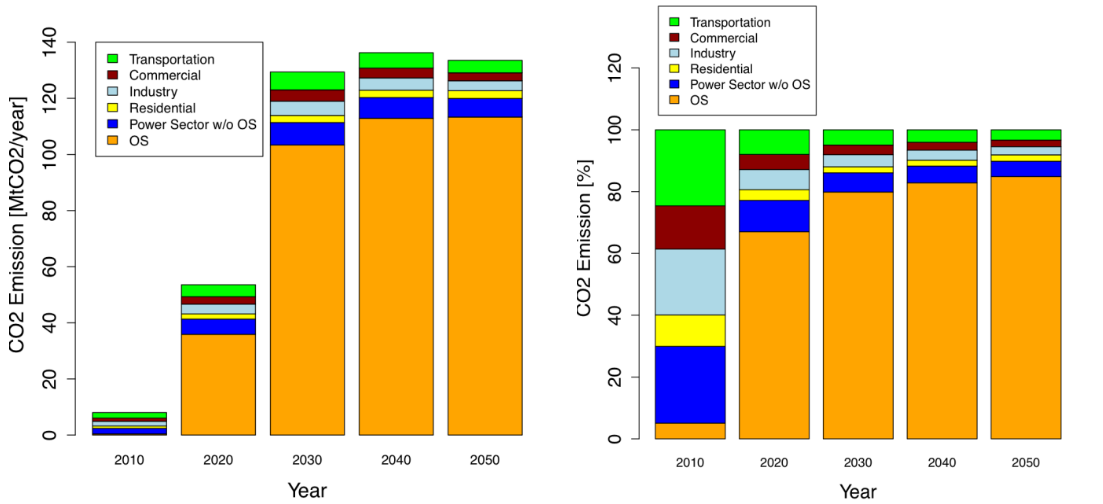

Figure 23 Left: CO_2 emissions by sectors. Right: Percentage

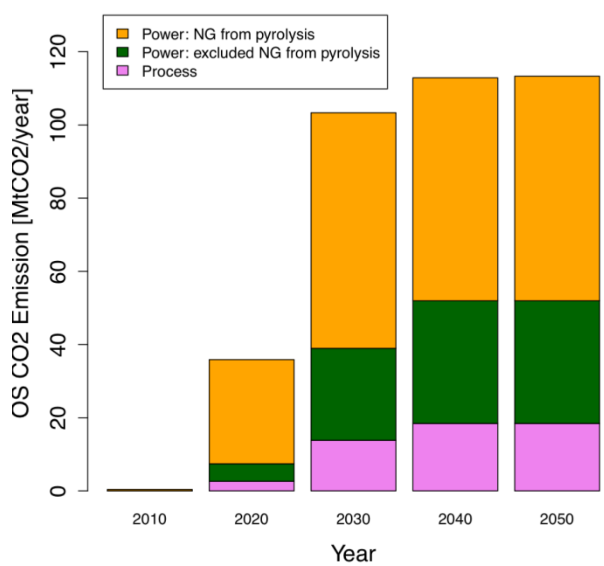

Figure 24 Oil shale CO_2 emissions for scenario S0; there are three contributions to the OS emissions: CO_2 from electricity generation produced using the natural gas recovered during the process (green), CO_2 from electricity generation obtained by a mix of natural gas, coal, and wind to meet the power demand that cannot be met burning the natural gas from the process, and CO_2 produced during cleaning up the pyrolysis natural gas to produce a saleable natural gas stream (Dooley et al. 2009)

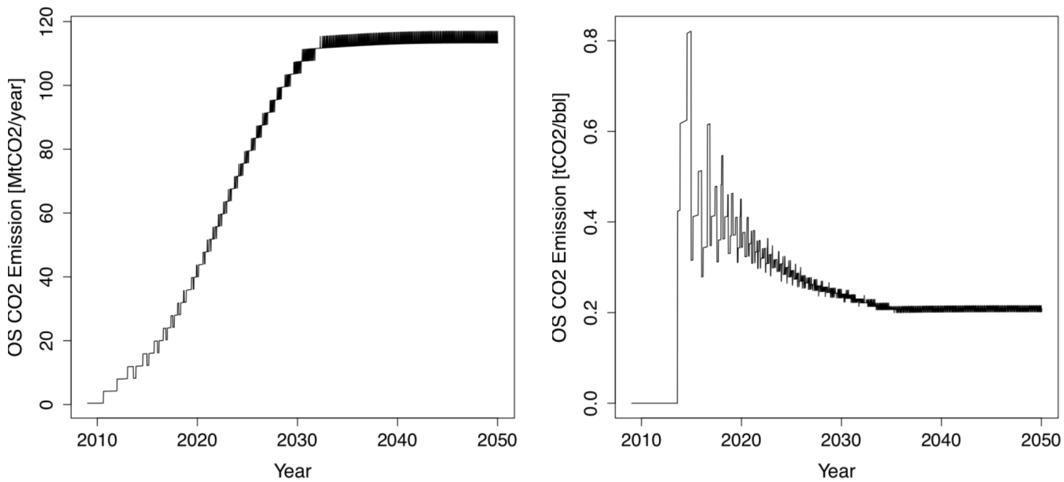

Figure 25 ***Left*****: Oil shale CO_2 emission.** ***Right*****: Oil shale CO_2 emission per barrel of oil produced.**

Simulated CO_2 emissions generated by the oil shale industry vary considerably depending on the energy mix used to generate the electricity required. At full operating capacity, the emissions in scenarios S1, S2 and S3 reach 93, 140, and 118 Mt of CO_2 per year respectively (Figure 26). Among these three alternative scenarios, we project scenario S2 to have the highest emissions due to the large amount of power produced by coal using an IGCC power plant, which has a high emission factor. Emissions generated in the scenario where all the electricity is generated burning natural gas (S1) are projected to be the lowest, whereas the scenario (S3), with 75% from coal, is comparable to the emissions generated in the baseline scenario. On a per barrel basis, in the alternative scenarios, emissions would reach 0.16 , 0.25 and 0.2 tonnes per barrel in 2040 as shown in Figure 26. On a per barrel basis, in the alternative scenarios, emissions would reach 0.16, 0.25 and 0.2 tonnes per barrel in 2040.

Relative to other economic sectors, the oil shale industry will rapidly become predominant in the region, both for economic activity, energy consumption and generation of CO_2 emissions. By 2015, in this simulated period, the oil shale industry (at 10% of its projected longer-term development) will generate as many emissions as the rest of the economy in the region. By 2040, emissions from oil shale will be 4 times higher than the rest of the local economy. In scenario S0, simulated emissions account for approximately 85%. In alternative scenarios, due to different energy mixes this amount declines to 82%, for scenario S1, but increases to 87% for scenario S2 by 2040, and 85% for scenario S3.

Carbon Dioxide Management

Given the level of simulated CO_2 emissions generated by the oil shale industry and the current political debate on the introduction of a climate policy, we have simulated the introduction of carbon capture and sequestration for the power production supporting oil shale operations (i.e. emissions capture from power generation and sequestration in suitable geological formations). In our analysis, we apply carbon capture and sequestration in scenarios S1, S2, and S3. If carbon capture with 90% efficiency (IPCC 2005) is adopted , emissions are projected to decline to 8.5 Mt of CO_2 per year for scenario S1, to 14 Mt of CO_2 per year for scenario S2, and to 11 Mt of CO_2 per year for scenario S3. Figure 26 and Figure 27 show the CO_2 emissions for the three scenarios without and with capture, respectively.

The capital cost of adding capture and sequestration is estimated on average at $600 per kW of power generating capacity (Rubin 2005). O&M costs are assumed to approximate $50 per MW of electricity produced and job creation is estimated at 20 employees per year per MW on average. Adding CO_2 capture will increase water consumption for additional power generation and capture process for a combined 115 million gallons per day in scenario S1, 112 million gallons per day in scenario S2, and 100 million gallons per day in scenario S3 at full operating capacity (see Figure 28).

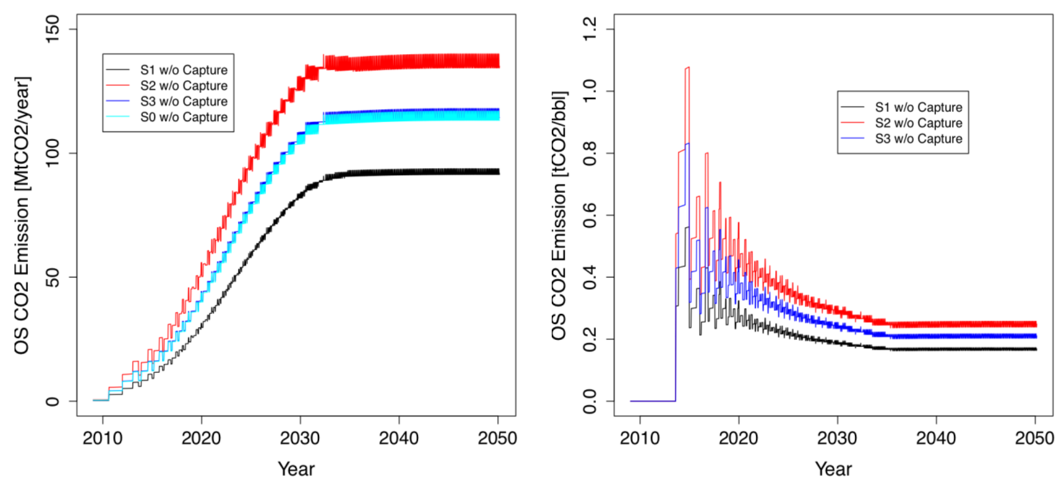

Figure 26 Left: CO_2 emissions for scenarios S1,S2, and S3 without CO_2 capture. Right: CO_2 emissions per barrel of oil produced for scenarios S1,S2, and S3 without CO_2 capture

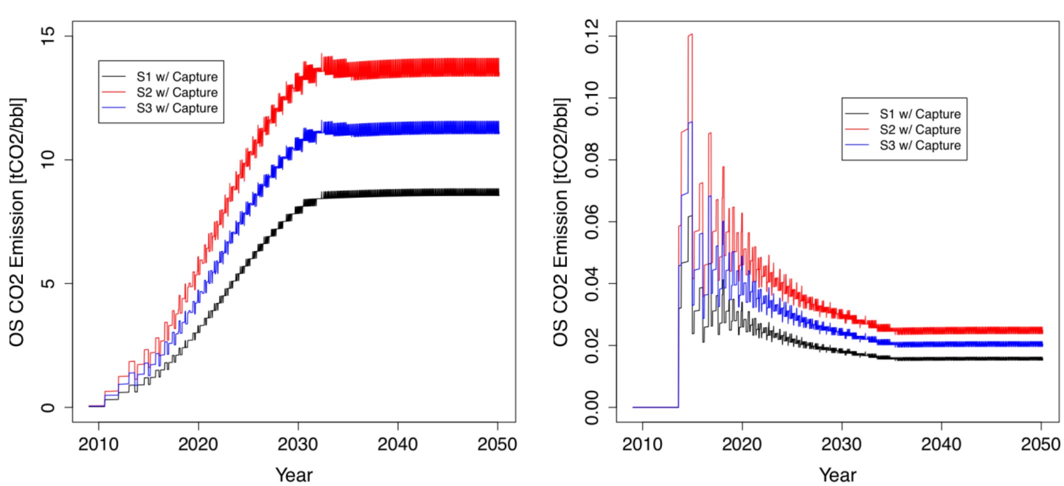

Figure 27 CO_2 emissions for scenarios S1,S2, and S3 with CO_2 capture.

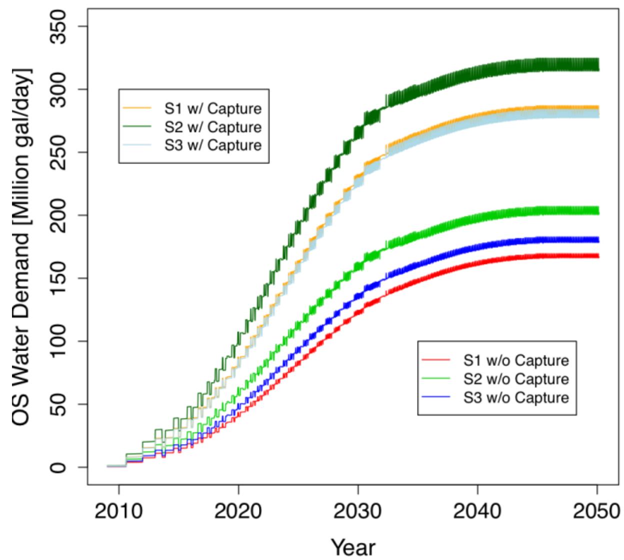

Figure 28 Water demand for scenarios S1, S2, and S3 with and without CO_2 capture.

Socioeconomic Impacts

Economic Impacts

The operating result for basin-wide oil shale production is calculated as revenues minus costs (both variable and capital) (Figure 29). Therefore, it is the result of the interaction of sales, oil prices, production, and capital costs. The operating result accounts for the actual capital investment (cash flow basis), but does not consider the amortization plan, which is calculated to represent the profitability of the industry for fiscal purposes.

The operating result is projected to be negative until 2021 in this simulation period for Scenario S0, when the output of 0.34 Mbbl/day is reached and production capacity of about 0.8 Mbbl/day is achieved. Before 2021, the operating result varies according to planned investments and increases in oil output. More specifically, before oil can be produced and sold in 2012, the industry loses an increasing amount of money every week. After 2012, the loss stabilizes as the gap between capital and variable costs and revenues shrinks. Nevertheless, since the investment in production capacity increases to reach its weekly maximum in 2020 while production lags behind investment, the operating result turns positive only in 2021. After 2021, with capital costs declining and production output increasing as well as oil price, the operating result remains positive and reaches $0.8 Billion/week after 2036, when the desired output of 1.5Mbbl/day is reached.

With high initial capital costs ($80,000 per bbl of daily production capacity, which accounts also for the capital costs of a NGCC power plant) and lags between construction and production, the initial average cost of oil recovered from shale is not able to compete with conventional light oil. As capital costs decrease and production increases, reaching a significant magnitude, average production costs per bbl produced decrease (Figure 30). More specifically, the cost decreases from about $250/bbl to

$45/bbl when the desired production level of 1.5 Mbbl/day is reached. However, this estimation does not account for eventual carbon management costs.

The projection of the average cost of production takes into account the timing of the four production phases as well as the timing of the variable costs associate to them (i.e. energy and water use). Variable costs decrease over time because drilling and heating are performed before recovery. Therefore, the energy and water cost per unit produced, as well as capital expenditure, are higher than in steady state, because the investment into production inputs takes time to come to fruition.

Due to the initial need of capital and the lag times between investment and producing oil from shale, the capital cost is the most important cost component in the early phases of the oil shale industry development. In 2020, however, with growing output and construction at its peak, capital costs constitute 50% of the average production cost per barrel. With declining and then constant needs of capital construction and stable output, the capital cost accounts for only 19% of the production cost per barrel in 2040, versus 80% of the variable cost in these simulations for case S0.

Labor needs related to the oil shale industry in the studied region are associated with construction, operation, and management of the facilities. It is assumed that construction is more labor intensive than management as reflected in the projection of total employment (Figure 31); total employment peaks in 2026, shortly after the capacity under construction reaches its maximum. In these projections, a maximum of about 300,000 workers will be employed by the oil shale industry for directly related work. At the steady state production level, after 2040, the number of employees is estimated to be slightly above 260,000.

Weekly employment rates (Figure 31) show projected behavior consistent with the assumptions on investment and on labor intensity for construction and operation and management. Employment in construction follows the steps in planned investments, showing three peaks in 2012, 2016 and 2019. After construction peaks in 2019, simulated employment gradually declines, reaching its minimum value (on a weekly basis) in 2030.

The lowest value for the number of employees in the construction phase is reached in 2040, once the desired production level is reached. Construction employment after 2040 will only be associated with building discarded production capacity (the capital lifetime is assumed to be 30 years). Operations and management employment grows gradually over time, reaching its peak at the completion of production capacity, in 2021. At its maximum, about 245 workers are hired weekly for O&M purposes. With the *ReIMAE*, we also estimate the creation of indirect jobs resulting from the oil shale production activity in the region of interest. These use assumptions obtained from the report prepared by the University of Utah (Utah Heavy Oil Program 2006). It is assumed that new indirect jobs are mostly created once the production capacity is in place and new O&M employees start relocating to the region considered. At this time, public infrastructure and services will need to be improved and housing, dining, and distribution facilities will need to be built.

In alternative scenarios (for both CCS and power generation) capital and variable costs differ. Specifically, investing in CCS increases capital, O&M, and water costs, while it reduces emissions expenditure. In addition, CCS increases employment in the area. In the case of power alternatives, investing in renewable energy has a higher capital cost, but also higher employment and lower risk to energy price volatility.

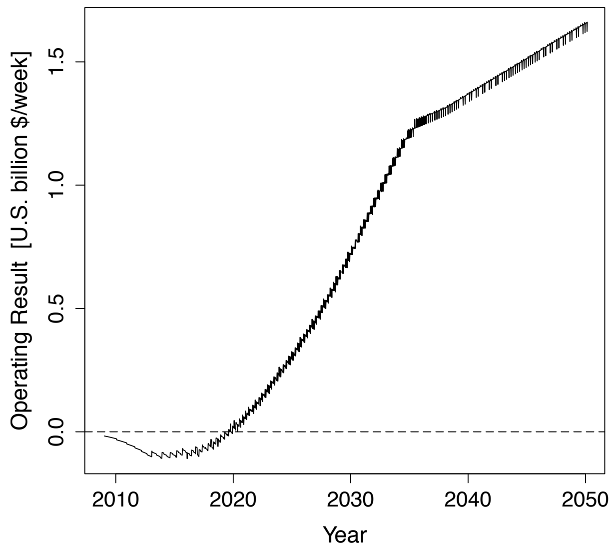

Figure 29 Oil shale operating result, a proxy for the economic profitability of operations, is the difference between the total revenues and the total costs. Revenues come from selling the extracted oil. The total costs encompass construction costs and variable costs. The latter account for the cost of labor compensation, water, and energy

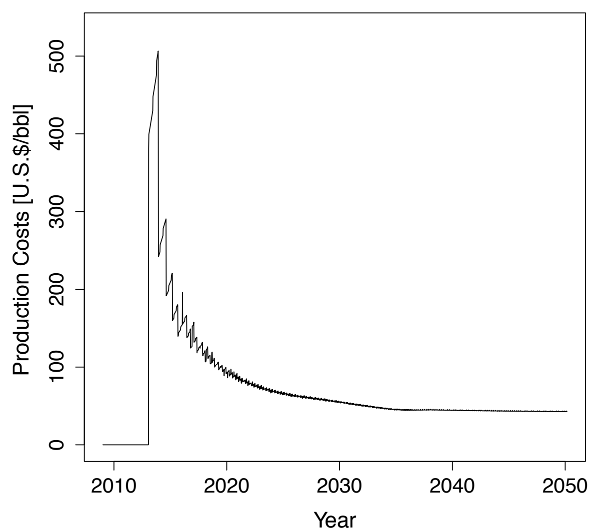

Figure 30 Total production costs per barrel of oil produce. The total production costs include construction and variable costs. The construction cost per barrel is assumed constant over time and includes the costs of building a power plant to generate the internal electricity. The variable costs encompass the costs of labor, water, and energy needed

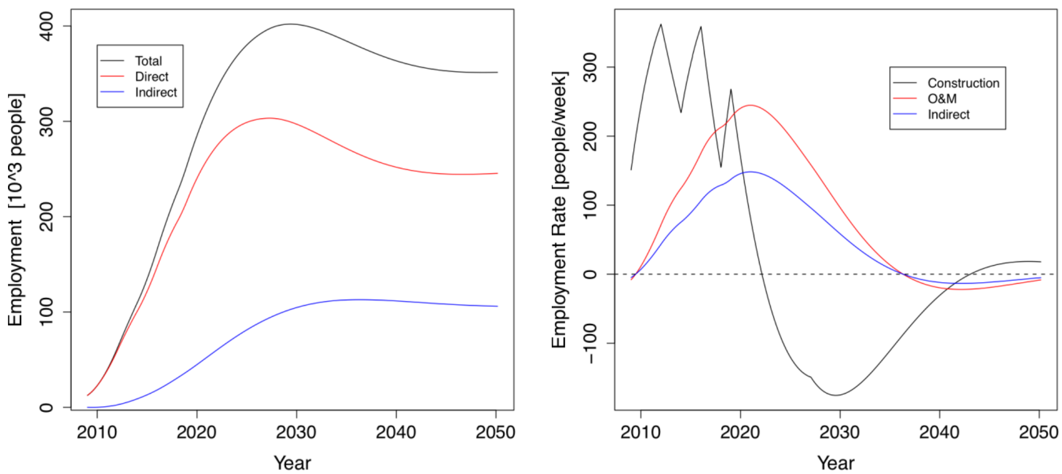

Figure 31 : Baseline scenario: Employment (left) and employment rate (right)

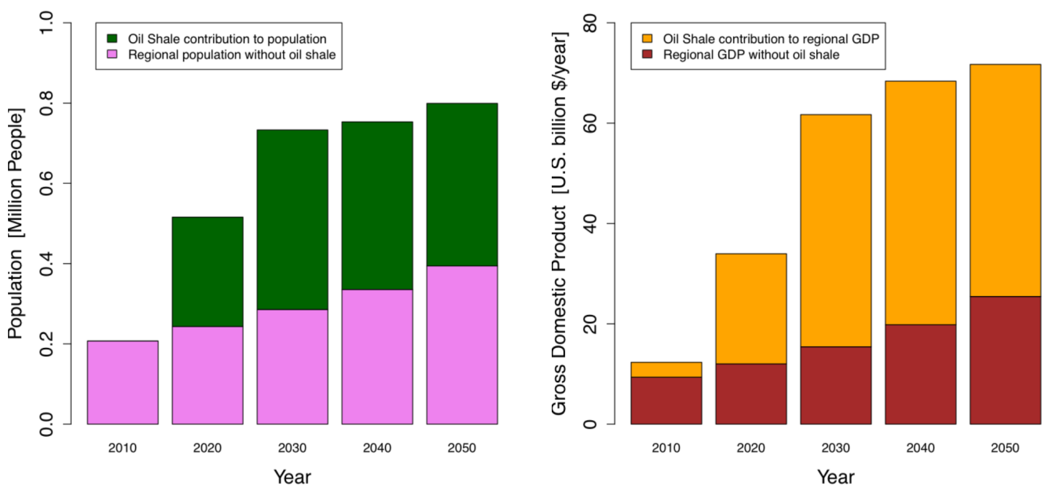

Figure 32 Left: Population growth: oil shale industry contribution (green) to local population and population in the region of interest without the oil shale industry development (violet). The oil shale industry contribution includes population that moved to the area only due to the oil shale business (i.e. direct and indirect employment and family members), and its natural growth over time. Right: Gross Domestic Product: oil shale industry contribution to the local economy GDP_{uff} (orange) and local GDP_{reg} without the oil shale contribution (brown). All values are expressed in real terms, using 2000 as base year

Social Impacts

The regional impact of a potential new oil shale industry is sizable when comparing simulated resident population in 2009 and 2040. While the population currently residing in the region totals almost 0.2 Million, it is projected that by 2040, the total will be over

0.8 Million people (Figure 32). This population growth will be due to people moving into the region for direct and indirect jobs, bringing their families, and the associated population growth. Oil shale production could contribute between $16 and $20 billion, and between $2.4 and $3 billion, annually to the Federal and State governments, respectively and it could add $72 billion per year to GDP by 2040, or about 0.63% of national GDP in 2008 (Figure 32). All values are expressed in real terms, using 2000 as the base year; conservative assumptions used in the calculation of the contribution to GDP are based on NSURM (2006).

Conclusions

In this project, we developed an integrated assessment model that can assist in answering questions regarding water requirements, carbon management strategies, and socio-economic impacts and benefits associated with the development of basin-wide fuel production. We applied this model to scenarios representative of basin-wide oil shale development in the western interior of North America, and includes parts of Colorado, Utah, and Wyoming.

ReIAME enables cross-sectoral analysis and assessment of dependencies and feedbacks. Here, it is applied to a set of hypothetical basin-wide development scenarios with an approximation of the processes associated with the Shell ICP. Parameters are estimated based upon publically available data, so the model does not replicate the exact Shell system. However, the *ReIAME* demonstration highlights how information is assimilated and how interactions of multiple sectors can be easily evaluated. Here, we demonstrate how the model can track energy and water demands and CO_2 emissions over the course of basin-wide development. The model results show the industrial ramp up and the time dependence of the processes associated with developing the fuel and then restoring the subsurface environment. The modularity of the model, as built for this project, enables ready evaluation of alternative constraints, such as those that might be imposed as a result of carbon management policy. The model is capable of operating under specified time-varying supply and computing the rate of fuel production or new storage capacity required to meet a target production rate.

For this project *ReIAME* was applied to oil shale production, however its modularity and the generic approach used model enable to apply *ReIAME* to study the implications of the development of any fuel industry.

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Appendix: RelAME Components

This chapter describes *ReIMAE* in detail, module by module, with a focus on purpose, assumptions, and functional explanation.

Oil Shale Production Process

The *Oil Shale Production Process* module represents the production process of oil shale in order to calculate the fuel production and energy and water consumption. The *Oil Shale Production Process* module is central to the model, providing inputs to most of the other modules. In this module, we simulate the four phases of the Shell In situ Conversion Process (Shell 2006) (ICP) described previously including the phases of drilling, heating, recovery and restoration.

The U.S. Department of the Interior projected that the surface area impacted by a domestic oil shale industry development would be about 21 square miles to recover a max production of 1.5 Million barrel per day in 30 years (SPE 2007, NSURM 2006). In the model, the production area (21 square miles) is divided into square production cells, 380x380 square meter as reported by Brandt (2008), forming a grid. Each cell contains 1190 wells, used for freezing, dewatering and oil extraction. Each cell development consists of four phases that approximately describe the ICP:

1. Drilling phase: includes drilling for freezing, freezing process, dewatering and drilling the producer wells
2. Heating phase: heating the rocks through electric heaters
3. Retorting phase: pumping out the recovered product
4. Reclamation phase: flushing the pyrolyzed area

Each phase is characterized by a specific duration, water, and energy requirements within each cell. We assume that the total water amount used for the process is 1 gallon per barrel of oil (DOE fact sheets, BLM 2008), of which 3.6% is for drilling, 3.1% is for production, and 93.4% is for reclamation (BLM 2008). In the model, the heating phase does not require water. We assume an energy need per barrel of extracted oil of 334 kWh for heating the oil shale by electric heaters, 19.48 kWh for drilling and freezing, 0.425 kWh for oil extraction (pumping), and 11 kWh for reclamation (Brandt 2008). Based on the Oil Shale Test Project prepared by Shell for the Bureau of Land Management (Shell 2006), we assume that to drill, heat, produce, and restore a cell 1, 3, 3, and 11 years are needed respectively.

In the model, cells are developed sequentially and the model advances to next cell with completion of activities in previous cell (e.g. drilling is a continuous process). In other words, once the drilling phase of the first cell is completed, the heating phase on the first cell starts and at the same time the second cell's drilling phase begins, and so on. Each phase is characterized by a specific duration, energy and water needs. Using a discrete event modeling approach, the model represents heating, production, and reclamation phases using three conveyors. Once drilling of a cell is complete, the cell is ready to be heated and is placed on the conveyor that simulates the heating phase. Each conveyor has a specific speed and length, ensuring that each cell stays on the conveyor for the duration of that specific production phase. However, the speed of each conveyor is a function of the availability of water and power. If the supplies of water and power do not meet the actual demands of that specific production phase, the speed of the conveyor decreases proportionally to the discrepancy between supplies and demands, increasing as a consequence the time to accomplish the specific production phase for the cells that, at that time, are on the conveyor. Once the cell is heated, it is placed on the retorting conveyor and after that on the reclamation conveyor.

For each conveyor we calculate the number of cells, n_k, that at time t are in the production phase k; the demand of water (d^w)and power (d^e) for each phase are estimated as follows:

$$d_k^w(t) = n_k(t) * w_{k,cell} \quad k = drilling, heating, retort, reclam. \tag{1}$$

where w_k is the water demand for the production phase k, and $w_{k,cell}$ is the water demand per cell during the phase k. Analogously,

$$d_k^e(t) = n_k(t) * e_{k,cell} \quad k = drilling, heating, retort, reclam. \tag{2}$$

where d_k^e is the energy demand for the production phase k, and $e_{k,cell}$ is the energy demand per cell of the k phase. d_k^w is the water demand for the production phase k, and $w_{k,cell}$ is the water demand per cell of the k phase

In the model, the pyrolysis water obtained during the retorting process and the water recovered from dewatering during drilling and retorting is reused in the process for reclamation. Typically, oil shale contains to 2–5 gallons of water per tonne of shale (DOE fact sheet, Bartis et al. 2005). As a first approximation, we assume to recover 3.5 gallons per ton of shale, which will be used for reclamation. In addition the model assumes one third of the pyrolysis product from the retorting phase to be natural gas (Bartis et al. 2005, Utah Heavy Oil Program 2007) that is entirely used for generation of electricity through a natural gas-fired power plant with 55.8% efficiency (Rubin 2005).

The main outputs of the *Oil Shale Production Process* module are the total demands for energy and water (water needed for the process only) through time for each phase, which can be estimated as follows:

$$\begin{aligned} W_{tot}^p(t) &= \sum_k d_k^w(t) \quad k = drilling, heating, retort, reclam. \\ E_{tot}(t) &= \sum_k d_k^e(t) \end{aligned} \tag{3}$$

Installed fuel production capacity and energy and water availability drive the production process; they are inputs for the *Oil Shale Production Process* module. Available production capacity, calculated in the *OS and Regional Economics* module, determines the number of wells that need to be drilled, per week, during the simulation, setting the production process dynamics. The speed of each production phase depends on the available supplies of water and energy to support the requirements. Although this capability is now built into *ReIAME*, we assume here that supplies are sufficient to meet all the demand.

Figure 33 shows the relationships and feedbacks among production, water and energy demands and supplies for each production phase. The number of cells directly determines water and power demands for each phase at that time. The total water supply (S_w), defined in the *Water Sector module*, is divided into water supply needed for the 4-phase production process (S_w^p) and water needed to produce the required electricity (S_w^e) proportionally to the demands:

$$S_w^p(t)=\frac{S_w(t)*d_w^p(t)}{d_w^p(t)+d_w^e(t)} S_w^e(t)=\frac{S_w(t)*d_w^e(t)}{d_w^p(t)+d_w^e(t)}$$

S_w^p is equally distributed in each phase, determining the water supply for the production process for each phase. d_w^e ,water demand for power generation, depends on the energy demand (d^e). However, d^e defines the water supply for power needed to calculate the power supply, S_e, in the *OS Energy* module. S_e links back to the *Oil Shale Production Process* module to determine the power supply needed to define the speed of the conveyor for each production phase as follows:

$$S_e^k(t)=\min(\frac{S_e(t)}{4},d_k^e(t)) \tag{4}$$

where *k* defines a production phase among the 4 phases, which characterize the production.

<u>Major Assumptions</u>

- The area impacted by oil shale production is finite. The total area analyzed equals the amount of land (21 square miles) that will need to be drilled, heated and restored to reach the desired production level of 1.5 million barrels per day (SPE 2007, NSURM 2006).
- The four production phases analyzed, drilling, heating, retorting, and reclamation, are characterized by durations of 1, 3, 3, and 11 years, respectively (Shell 2006).
- The water necessary to drill wells, recover oil and restore cells can be obtained from two sources: it can be recovered during the drilling phase, and/or it can be purchased. We assume we can recover all of the water held in the shale (3.5 gallons per ton of shale) and purchase the remaining demand (thus examining, here, what the additional demand on the regional rivers or, potentially, groundwater would be).
- The four production phases analyzed are characterized by different energy and water needs. We assume that the total water amount used for the process is 1 barrel per barrel of produced oil (DOE Fact Sheet), of which 3.6% is for drilling, 3.1% for recovering, and 93.4% for reclamation (BLM 2008).

- We assume an energy need per barrel of extracted oil of 334 kWh for heating the oil shale by electric heaters, 19.48 kWh for drilling and freezing, 0.425 kWh for oil extraction (pumping), and 11 kWh for reclamation (Brandt 2008). .

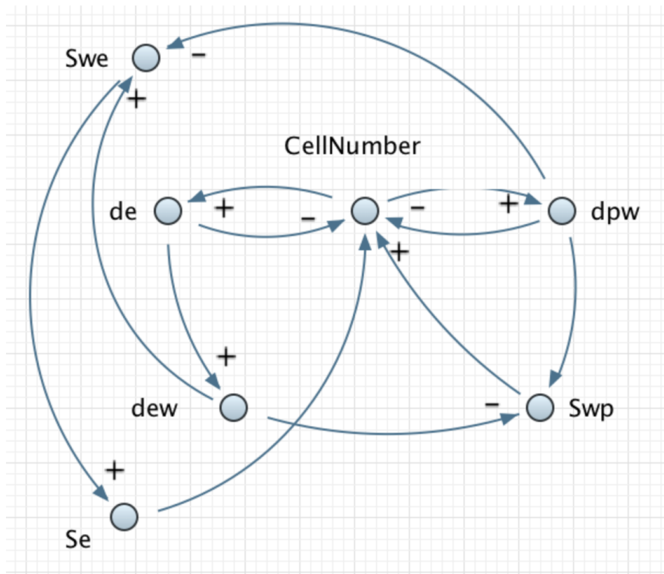

Figure 33 Feedback loops among production, water and energy demand and supplies. Energy: de is the energy demand, dew is the water demand for power, Se is the total energy supply available based on Swe, the water supply available for power generation. D_{pw} is the water demand for the process, and S_{wp} is the water supply available for production

Table 2 Oil shale production process module: Input variables

Variable Name	Value	Unit	Source
Capital to Cell Ratio	0.0000372884	Cell/Bbl/Day	Calculated (INTEK)
Cell Area	35.7	Acre/Cell	Brandt
Cell Area Heated	90,000	Meter	Brandt
Desired Number of Bbl Output per Week	17.5M	Bbl/Week	INTEK
Desired Number of Wells per Week	710	Well/Week	Calculated (INTEK)
Desired Total Bbl Output per Day	1.5 M	Bbl/Day	INTEK
Drilling Energy per Well	262.9	kWh/Well	Brandt
Drilling Water per Well	35493	Gallon/Well	Calculated (BLM)
Gallons to Bbl Conversion	42	Gallon/Bbl	EIA
Heating Duration	156	Week	Shell, NETL
Heating Energy per Barrel Produced	275	kWh/Bbl	RAND
Heating Water per Cell per Week	0	Gallon/Week/Cell	BLM
Well Diameter	8.7	Meter/Well	Brandt
Mcf of Gas per Week per Cell	187725.3	Mcf/Week/Cell	Calculated (INTEK)
MJ to Bbl	6119.32	MJ/Bbl	EIA
MJ to kWh	0.277	kWh/MJ	EIA
Production Duration of One Cell	156	Week	Assumption
Production Water per Barrel Produced	1.31	Gallon/Bbl	DOE, BLM
Restoration Duration	52	Time	Assumption

Variable Name	Value	Unit	Source
Restoration Energy Per Ton	39	MJ/Ton of Shale	Brandt
Restoration Water per Barrel Produced	39.25	Gallon/Bbl	DOE, BLM
Retorting Energy Per Ton	1154	MJ/Ton of Shale	Brandt
Shale to Oil Conversion	0.04	Ton/Gallon	RAND
Time to Water Recovery	1	Week	Assumption
Tons of Shale per Well	11.95	Ton/Well	Calculated (Brandt)
Total Area	33280	Acre	INTEK
Total Operation Duration	1560	Week	INTEK
Water Recovered per Ton of Shale	3.5	Gallon/Ton	DOE
Water Recovered per Well	144930	Gallon/Week	Calculated (DOE)
Water Recovery Fraction	1	Dmnl	Assumption

Table 3: Oil shale production process module: Input variables from other model modules

Variable Name	Module of Origin
Production Capacity	UFF and Regional Economics
UFF Energy Supply Auto Generated	Process In Situ Energy
UFF Energy Supply from Grid	Power Sector
UFF Water Supply from Reservoir	Water Sector

Table 3 Oil shale production process module: Output variables to other model modules

Variable Name	Module of Destination
Cumulative UFF Bbl Output	UFF and Regional Economics
UFF Bbl Output per Day	CO_2 Emissions UFF and Regional Economics
UFF External Water Demand	Water Sector
UFF Mcf Output per Week	Process In Situ Energy
UFF Total Energy Demand	Power Sector

Oil Shale Energy Module

The *Oil Shale Energy* module is used to calculate the amount of electricity that is generated from natural gas produced during in situ retorting of oil shale and the remaining energy demand from the mix of additional natural gas, coal, and/or renewable resources as described in the scenario definitions. In the first part of the *Oil Shale Energy* module, we calculate the electricity generated burning the pyrolysis natural gas, the water demand associated with that energy generation, and the related CO_2 emissions. In the second part, the model calculates the remaining energy demand for the user-specified mix, the water consumption related to that energy production, and the associated CO_2 generation. The model estimates the capital and operational costs associated with the electricity generation and the related employment contribution.

Electricity generation: natural gas from pyrolysis

We assume that all natural gas recovered from the production process is used for electricity generation; one third of the recovered hydrocarbon product is natural gas (Bartis et al. 2005, Utah Heavy Oil Program 2007, NSURM 2006). We assume that during the retorting phase 1,000 cubic feet of natural gas can be recovered per one barrel of oil produced (NSURM 2006). As a first approximation, all natural gas recovered is readily available for use in electricity generation; we do not currently model any treatment process to separate the natural gas stream from the other pyrolysis products (water and hydrocarbons) and CO_2 nor to clean it up to meet the standard pipeline quality specifications. Electricity is generated burning the natural gas in a combined cycle natural gas (NGCC) power plant with efficiency se at 55.8% (Rubin 2005).

The weekly output of natural gas (*ng*) is calculated in the *Oil Shale Production Process* module and imported into the *Oil Shale Energy* module in units of million cubic feet per week (Mcf/week). In order to calculate its electricity output, the natural gas stream is converted into energy input to the natural gas turbine, E_i^{ng}, expressed in British thermal unit per week (Btu/week) as follows:

$$E_i^{ng} = ng * \alpha * \beta \qquad (5)$$

where α converts Mcf into cubic feet (cf), and β is the conversion factor from ct to Btu. We assume that the power plant has an efficiency (η) of 45%, which determines the actual useful energy output, E_o^{ng}:

$$E_o^{ng} = E_i^{ng} * \eta \tag{6}$$

This is then converted into electricity equivalent for the natural gas extracted during the oil production process, expressed in kWh/week (E_{ng}):

$$E_{ng} = E_o^{ng} * \gamma \tag{7}$$

where γ is the conversion factor from Btu to kWh.

The module estimates the power plant water consumption, w^{ng}, by multiplying the net electricity output by the water consumption per 1 MWh:

$$w_{ng} = E_{ng} * \omega \tag{8}$$

where ω is the water consumption per 1 MWh for a NGCC power plant based on a cooling water system utilizing recirculating cooling towers. We assume ω is constant over time and set at 190 gal/MWh (without carbon capture) as reported by NETL (2008). Analogously to water, the module calculates the amount of CO_2^{ng} emissions created as,

$$CO_2^{ng} = E_{ng} * \phi \tag{9}$$

The emission factor (ϕ), correspondent to the generation of 1 MWh of electricity, is constant over time and set at 367 Kg of CO_2 per MWh as reported by Rubin et al. (2005).

Electricity generation: remaining demand

Natural gas recovered from the production process is not enough to meet the total oil shale energy demand, E_{tot}^{dm} (including during start-up, before any natural gas is produced from pyrolosis, but heat is required). The remaining demand, E_*^{dm}, is met with other resources. The difference between the total demand and the energy produced using pyrolysis natural gas, is met with electricity from alternative sources. Four different scenarios are described earlier in this section and *ReIAME* allows simple user input to specify the desired mix of power sources to consider. At this stage, the *ReIMAE* considers three different energy sources to produce electricity: coal, natural gas, and renewable. For coal, with supercritical pulverized coal (SPC) or integrated gasification combined cycle (IGCC) plant are permitted; for natural gas, the technology used is NGCC. For renewable energy, wind power is currently available in the model.

In the first scenario, with a combination of four energy sources, we express the total energy demand, imported from the *Oil Shale Production Process* module, as follows:

$$E^{d}_{tot} = \sum_{i} E^{d}_{on}(i) \quad i = ngcc, pc, igcc, wind \tag{10}$$

where $E^{d}_{on}(i)$ is the specific energy demand of technology *i*. $E^{d}_{on}(i)$ can be written in the following way:

$$E^{d}_{on}(i) = \begin{cases} E^{d}_{*} * f_i + E_{ng} & if\ i = ngcc \\ E^{d}_{*} * f_i & if\ i \neq ngcc \end{cases} \tag{11}$$

where $f_i \in [0,1]$ represents the fractional contribution of the technology *i* to the energy demand E^{d}_{*}, which is

$$E^{d}_{*} = E^{d}_{tot} - E_{ng}. \tag{12}$$

E_{on}, the actual total electricity that can be generated to meet oil shale production, depends on the total water available for power, w^{s}_{p}, and on the electricity demand. At first, we calculate the water demand for each specific technology $w^{d}_{p}(i)$:

$$w^{d}_{p}(i) = E^{d}_{on}(i) * \omega_i \tag{13}$$

where ω_i is the water consumption factor (gallons of water per 1 kWh of electricity generated) for the technology *i*. NGCC requires the least amount of water demand followed by IGCC and PC.

The total water demand for power becomes

$$w^{d}_{p} = \sum_{i} w^{d}_{p}(i). \tag{14}$$

The total amount of water consumed to produce electricity (w^{cons}_{p}) is the minimum between the total water supply for power and the total water demand:

$$w^{cons}_{p} = \min(w^{d}_{p}, w^{s}_{p}). \tag{15}$$

The water supply for power is imported from the *Oil Shale Production Process* module where it is calculated. Assuming that the amount of water consumed by a specific technology is proportional to its water demand, the actual amount of electricity generated to meet the energy demand for each technology can be estimated as:

$$E_{on}(i) = \frac{w^{d}_{p}(i)}{\omega_i} * \frac{w^{cons}_{p}}{w^{d}_{p}}. \tag{16}$$

Finally, we calculate the total energy that is actually produced within water availability constrain as follows:

$$E_{on} = \sum_i E_{on}(i). \tag{17}$$

This value becomes an input into the *Oil Shale Production Process* module.

Knowing E_{on}, we also calculate the CO_2 emissions associated with the generation of E_{on}:

$$CO_2^{on} = \sum_i CO_2^{on}(i) = \sum_i E_{on}(i) * \phi_i \tag{18}$$

where $CO_2^{on}(i)$ represents the emissions generated by the technology *i*, and Φ_i is the CO_2 emission factor for this specific technology.

Electricity generation: CO_2 capture

In the scenario where CO_2 capture and sequestration (CCS) is incorporated, the *Oil Shale Energy* module takes into account the fact that the CCS process requires additional energy and increases the water consumption. The amount of additional energy and water varies by each specific power plant's electricity generating technology. In the CSS scenarios water and energy demands increase relative to non-capture scenario much more drastically for PC than for NGCC and IGCC cases.

The energy demand E_{on}^d becomes

$$E_{on}^d(i) = \begin{cases} (E_*^d * f_i + E_{ng}) * (1+\rho_i) & if\ i = ngcc \\ (E_*^d * f_i) * (1+\rho_i) & if\ i \neq ngcc \end{cases} \tag{19}$$

where ρ_i is the fractional contribution to the energy demand due to CO_2 capture related to the technology *i*. The additional water consumption required by the CCS process is also taken into account replacing in Equation 13 the water consumption factor ω_i with the water consumption factor for a power plant with capture ω_i^{cap}. We assume that 90% of the CO_2 emissions generated without capture can be captured for all technologies as reported by Rubin et al. (2005) and summarized by IPCC (2005).

Electricity generation: costs

The *Oil Shale Energy* module calculates the costs, fixed and variable, as well as the employment rate associated with the power plants with and without CO_2 capture. We assume that electricity generation from each plant type (NGCC, PC, IGCC, and wind) depends on both plant generation capacity, determined primarily by investment and discard, and by the plant's load factor. For thermal plants, fuel inputs are calculated.

Assumptions:

- Power generation capacity for each fuel type is determined by new investment, which uses assumptions on unit costs (per MW);
- O&M costs are calculated using the stock of production capacity;
- Employment is calculated for both construction and O&M.
- One third of the recovered product is natural gas (Bartis et al. 2005, Utah Heavy Oil Program 2007, NSURM 2006); We assume 1,000 cubic feet of natural gas per one barrel of oil produced, all of which is all used to generate electricity by a combined cycle natural gas power plant, with efficiency set at 55.8% (Rubin 2005);
- The emission factor for CCNG power generation is constant over time and set at 367 Kg of CO_2 per MWh, as reported by Rubin et al. (2005);
- The water requirement for CCNG power generation is constant over time and set at 190 gal/MWh without CO_2 capture, and 340 gal/MWh with CO_2 capture (NETL 2008);
- The remaining electricity is generated by a mix of different energy sources. Supercritical pulverized coal plant (SPC), integrated gasification combined cycle (IGCC) plant, and wind farms are the options *ReIMAE* allows at this stage;
- The maximum desired electricity production determines the power plants size;
- Power plant employment is disaggregated into two categories: construction of power plants and operating and management (O&M) jobs;
- Additional employment required for CO_2 capture is also disaggregated in construction and O&M;
- Labor requirements for construction and O&M change over time.
- The model includes the fuel as a variable cost (AEO 2010).
- The additional energy for carbon capture for each power plant is constant over time at 0.173, 0.314, and 0.155 for NGCC, PC, and IGCC respectively (Rubin et al. in 2007).
- The water requirement for each power plant with and without CO_2 capture is constant over time at 190, 450, and 310 gallon per MWh without capture, and 340, 840, 450 gallon per MWh with capture for NGCC, PC, and IGCC respectively. (NETL, 2008, 2009).
- The CO_2 capture system efficiency amounts to 90% for NGGC, PC, and IGCC (Rubin et al., 2005).
- The CO_2 emissions factors are 367, 762, and 773 kg of CO_2 per MWh for NGCC, PC, and IGCC respectively (Rubin et al. in 2007).

Energy Sector

The purpose of the *Energy Sector* module is to calculate all sources of energy demand and supply in the studied geographical area. Beside the oil shale industry, other sectors contribute to the total local energy demand; the model considers residential, water, commercial, industry, and transportation sectors. In this module, all of these energy demands are accounted for. Furthermore, this module estimates water consumption and emissions relative to electricity generation.

Energy for Other Sectors

The module calculates the energy demand, E^{d}_{other}, without the oil shale direct contribution, as the sum of the energy demands from the residential, commercial, industrial, water and transportation sectors:

$$E^{d}_{other} = \sum_j E^{d}_{j} \qquad j = res,\ com., ind., water, transp \quad (20)$$

where E^{d}_{j} are imported from the residential, commercial, industrial, water and transportation sectors modules, respectively. The regional energy consumption excluding the energy for the oil shale development is estimated as follows:

$$E_{other}=E^{d}_{other}*(1+\lambda) \qquad (21)$$

where λ represents the electricity losses and is assumed to be constant over time at 7.2%. The total water consumption, w^{cons}_{other}, to generate these electricity using coal and natural gas is calculated as follows:

$$w^{cons}_{other}=\sum_i E^{d}_{other}*g_i*\omega_i \quad i=ngcc,pc \qquad (22)$$

where ω_i, the water consumption factor for the technology *i*. g_i represents the fractional contribution of the technology *i* to the energy demand E^{d}_{other}.

CO_2 emissions generated from electricity production are calculated using the following relation:

$$CO_2^{other,E}=\sum_i E^{d}_{other}*g_i*\phi_i \quad i=ngcc,pc \qquad (23)$$

Φ_i is the CO_2 emission factor of the technology *i*. Although the total energy demand E^{d}_{other} does not directly account for the oil shale energy demand, E^{d}_{other}, w^{cons}_{other}, and $CO_2^{other,E}$ are indirectly impacted by the oil shale industry development: the residential energy demand, E^{d}_{res} in Equation 20 takes into account the direct and indirect contribution of the oil shale industry development to the local population.

Major Assumptions Summary

- Sectors that contribute to the total energy demand, excluding the oil shale industry, are residential, water, commercial, industry, and transportation;
- Energy supplies for all the sectors are assumed to be large enough to satisfy demand.
- Electricity losses are assumed to be constant over time, at 7.2%;
- The penetration of coal, natural gas and hydro/renewable energy is assumed to be constant in the present version of the model. Values were obtained from Brandt (2008).

Water Sector

The purpose of the *Water Sector* module is to calculate all sources of water demand, water supply, and energy demand for water treatment. Beside the oil shale business, other sectors contributing to the total regional water demand are residential, agriculture, water, commercial, and industry sectors.

At first, we calculate the total water demand, w_{other}^{d}, summing the demands of all the sectors:

$$\omega_{other}^{d} = \sum_j \omega_j^d \qquad j = res., ag., com., ind., OS \qquad (30)$$

where the water demand from the sector *j*, w_j^d, is calculated in the model component that represents the specific *j* sector.

CO_2 Emissions

The purpose of the *CO_2 Emissions* module is to calculate the total CO_2 emissions generated by the oil shale industry, the residential sector, and the economic sectors in the studied region. Initially, we determine the amount of emissions generated by all of the sectors excluding the oil shale industry. Residential and economic sectors (water, commercial, industry, and transportation) contribute to the total CO_2 emissions through energy consumption, and though other fuel uses, $CO_2{}^{other,\, no\, E}_{j}$. The total emissions of all these sectors can be written in the following way:

$$CO_2^{other} = CO_2^{other,E} + \sum_j CO_{2,j}^{other,noE} \; j = res., water, com., ind., transp \qquad (38)$$

Where $CO_2{}^{other,\, E}$ is the sum of all of the CO_2 emissions due to electricity generation for all the sectors except the oil shale industry. It is imported from the *Energy Sector* module. $CO_2{}^{other,\, no\, E}_{j}$ is the CO_2 emissions generated by the *j* sector, excluding those for energy consumption. The model accounts for contributions to the total regional CO_2 emission from the oil shale industry from energy production and from the byproduct of the retorting and recovery process (Dooley et al. 2009). The natural gas recovered during production needs to be cleaned up from other pyrolysis products including the CO_2 to meet the standard pipeline quality specifications. The total emissions from the oil shale production and from other sectors is written as follows:

$$CO_2^{tot} = CO_2^{os} + CO_2^{other}. \quad (40)$$

Some indicators are calculated to evaluate the carbon intensity of oil shale production and its impact on the region. These are emissions per barrel produced and the share of oil shale emissions over the total for the region.

Oil Shale and local economy

The purpose of the *Economics* module is to calculate and represent all costs and revenues incurred in the production of oil shale. The economic profitability of oil shale production is crucial to the development and growth of the industry. Operating surplus, and profit margins, should allow for the adoption of advanced technology and the retrofitting of production facilities, especially at the early development phases of the industry as experience and installed capacity grow. While revenues from production and government incentives are the main sources of cash for companies working in the oil shale business, a variety of cost factors should be considered when analyzing the economics of productions. These include both fixed and variable costs.

Production capacity and capital expenditure

A capital investment in plant construction and equipment has to be put in place to ramp up production capacity before the recovery of oil shale can actually start. The model accounts for a delay time in the construction of the plant (5 years). Additional delays are accounted for in various production phases (e.g. the heating process takes about 3 years before oil can be recovered). Thus, revenues can be generated starting from the 9th year after construction has started.

The model accounts for a linear capital depreciation rate over 20 years and the capital life time is assumed to be 30 years. After the targeted output production rate is reached, all discarded capital is assumed to be replaced to maintain the desired max production capacity.

Technology costs, such as retrofits (low-hanging fruit) or more structural and technological upgrades and additions (e.g. CCS) are treated separately in the *ReIMAE* in order to analyze options for projected increasing energy prices and the enactment of a climate policy that puts a price on carbon emissions.

Production capacity and capital are both treated as stocks -accumulations- in the model and represent a co-flow. Desired production capacity drives both investment and the construction of oil shale plants and facilities. While the production capacity follows two steps, construction and operation (2 stocks), and it is depleted by the discard of obsolete facilities and equipment, capital increases with the commissioning of new production capacity and decreases based on the 20 year amortization plan.

The main input for defining production capacity is a time series representing the planned investment in oil shale production. INTEK's production ramp up (NSURM 2006) was used to estimate this curve. Since we explicitly take into account a 5 year delay for construction and a 3 year delay for heating, INTEK's projected output was shifted back in time by 8 years in these simulations.

The variation in time of capital associated with production capacity, pc_{uc}, is defined as the difference between the order rate for new capital, pc_{or}, and the completion rate of capital, pc_{cr}, i.e. its installation and availability for use:

$$\frac{d(pc_{uc})}{dt}=pc_{or}(t)-pc_{cr}(t) \tag{41}$$

where

$$pc_{cr}(t)=\frac{pc_{uc}}{t_{pcc}} \tag{42}$$

and t_{pcc} is the average construction delay, i.e. lag time between the order and completion of the plant. We calculate the first term of Equation 41, pc_{or}, as follows:

$$pc_{or}(t)=\frac{pc_d-pc}{t_{pcc}}+pc_{dr} \tag{43}$$

where pc_d is the desired level of production capacity available and in place, pc is the actual level of production capacity available, pc_{dr} represents the discard rate of capital or its disposition at the end of the capital life time. We estimate pc solving the equation:

$$\frac{d(pc)}{dt}=pc_{cr}(t)-pc_{dr}(t) \tag{44}$$

and

$$pc_{dr}(t)=\frac{pc}{t_{pcd}} \tag{45}$$

where t_{pcd} is the average capital life time, i.e. lag time between the completion of the plant and its disposal.

Capital order rate determines the capital invested, I_c, through the investment rate, I_r, as follows:

$$\frac{d(I_c)}{dt}=I_r(t)-cd(t) \tag{46}$$

where cd is the capital depreciation defined as:

$$cd(t)=\frac{I_c(t)}{t_d} \tag{47}$$

and t_d is the depreciation time of capital, which is driven by the amortization plan simulated, assumed to be 20 years. We determine I_r as follows:

$$I_r(t)=pc_{or}(t)*cb(t) \tag{48}$$

where cb is the capital cost of new production capacity per barrel of output.

Direct and indirect employment

Direct and indirect employment are driven by the development and expansion of the oil shale business in the studied region, which is largely determined by the oil shale reserves in the area and by the allocation of funds to ramp up production capacity.

Direct employment, L_{dir}, is calculated as the sum of employees hired to carry out both construction and operating and management (O&M) activities. Specifically, the actual construction employment, L_c, that is the number of workers employed to build infrastructure, is calculated by multiplying the capacity under construction by the number of workers required to build 1 barrel of daily production capacity, φ:

$$L_c(t)=pc_{uc}(t)*\varphi. \tag{49}$$

While the functioning production capacity in place (pc) drives the O&M employment, L_{om}, that is the number of workers employed to run the available infrastructure:

$$L_{om}(t)=pc(t)*\varsigma \tag{50}$$

where ς is the labor intensity of the operation and management of production capacity, expressed as people per barrel of production capacity. For an economic analysis, it is important to consider not only the employment, but the employment rate as well. The construction employment rate, that is the weekly rate of workers employed to build ordered production capacity, L_c^r, is calculated as the difference between the actual capacity order rate and the capacity completion rate:

$$L_c^r(t)=(pc_{or}(t)-pc_{cr}(t))*\varphi. \tag{51}$$

While the rate of the workers employed to operate and manage production capacity, L_{om}^r, is proportional to the difference between the actual infrastructure completion rate and the capacity disposal rate:

$$L_{om}^r(t)=(pc_{cr}(t)-pc_{dr}(t))*\varsigma. \tag{52}$$

Indirect employment rate, L_{ind}, is obtained by multiplying the total oil shale direct employment by a multiplier, τ, that represents the creation of non-oil shale jobs driven by the expansion of the oil shale business, e.g. housing, infrastructure and other commercial activities. Using a study from the University of Utah (Utah Heavy Oil Program, 2007), it is estimated that for each direct job created by the oil shale industry, 0.6 additional ones are created in other economic activities.

$$L^r_{ind}(t)=L^r_{dir}*\tau=(L^r_{om}(t)+L^r_c(t))*\tau. \qquad (53)$$

Fixed and variable production costs

Since the economic profitability of the industrial production of oil shale is a prerequisite for the development and expansion of the industry, it is necessary to track and project revenues, *R*, and costs. Among the latter, we represent fixed (C_c) and variable costs (C_v), consisting respectively of capital costs, and expenses for labor compensation (C_l), energy (C_e) and water (C_w) consumption and carbon emissions produced (C_{em}) -when applicable. The total costs, C_t, consist of the sum of the fixed costs, C_c, and the variable costs, C_v

$$C_t(t)=C_c(t)+C_v(t). \qquad (54)$$

In this project, capital costs encompass the cost of all equipment and processes (e.g. drilling and heating) necessary for the production of oil when using the ICP, and the costs to build and maintain an NGCC power plant used to produce electricity burning the natural gas recovered during production process. Capital costs are calculated by using a 20 years depreciation schedule, which reduces the value of the capital invested. In order to estimate the capital costs we assumed that (1) the cost per barrel of installed production capacity equals $80,000 (NETL 2006), (2) capital has a 30 year lifetime and 20 years depreciation schedule, and (3) the desired oil shale production reaches 1.5 Mbbl/day by 2040 as projected by NSURM (2006).

Variable costs include the production factors directly employed in the production process, such as labor, energy and water. The cost of carbon emissions is also included in the model and it is calculated for scenarios that include the enactment of a carbon policy. The variable costs are calculated as follow:

$$C_v(t)=C_e(t)+C_l(t)+C_w(t)+C_{em}(t) \qquad (55)$$

where C_e , C_l , C_w , and C_{em}, are the costs for energy, labor compensation, water, and carbon emissions respectively. Energy and water expenditure are driven by oil production activities (drilling, heating, recovery and restoration), which take into account the timing of the different phases. Therefore, energy expenditure is high in the early steps of production during the heating phase, while water consumption (not including water demand for energy production) is at its highest when reclamation, the last step, takes place. We determined the energy cost as follows:

$$C_e(t)=E_{off}*ep \qquad (56)$$

where *ep* is the electricity price, which, in the base scenario, follows the EIA projections (Dooley 2009). E_{off}, is the consumption electricity and it is imported by the *Energy Sector* module. The cost of water is estimated as follows:

$$C_w(t)=w^s_{tot}*pw \qquad (57)$$

where *pw* is the water price (Bunger et al. 2009). w^s_{tot} is the oil shale industry water consumption, which is the sum of the water consumption for power generation and the water needed during production process.

Labor costs are calculated on an annual basis, first by multiplying the operation and management workers by the average annual wage of workers in the analyzed region and in the oil shale business. Since the average annual wage of the considered area without oil shale business was $34,292 in 2005 (Utah Heavy Oil Program 2007) and the actual average wage in the oil and gas industry is $66,720 (BLS 2009), we assumed that the average annual wage of workers in the oil shale business in the region will reach the national average by 2040 (through a 30 year linear adjustment), which would be when the oil shale industry will attain the target output of 1.5 Mbbl/day. Carbon emission costs can be calculated by multiplying the total amount of emissions originating from oil shale production activities by a potential carbon price

Profitability of the industrial activity (operating surplus and profit)

The only source of revenue considered in this study for oil shale operations is the sale of recovered oil. We assume that all natural gas recovered from the field is used for internal electricity generation. As a consequence, revenues are calculated by multiplying projected production by the price of oil forecasted by the EIA in the AEO (2010).

The difference between total revenues and total costs gives the operating result, *O*. This indicator is a proxy for the economic profitability of operations and includes all administrative costs, taxation and actual profits.

$$O(t)=R(t)-C_t(t) \tag{58}$$

A second formulation was adopted to analyze the actual cash flow of the industry. In this case, the operating result is calculated by subtracting investment and variable costs from revenues.

Because it is very difficult to estimate what the actual administrative costs could be for an oil shale operation of this projected size, we drew from the results of other studies and calculate the projected profit of the oil shale business by multiplying total revenues by the desired rate of return, set at 15% in the base case (NSURM 2006).

Indirect economic benefits to the economy and the public sector.

Building an oil shale plant requires material, labor and energy inputs. While materials can be shipped to the construction site and energy can be delivered (after power plants are built), workers will be brought to the construction site and neighboring areas where they will stay for a few years. Consequently, public infrastructure will need improvement and expansion; the public grid will need to be upgraded to adequately supply shale oil energy intensive operations; and housing units will be built. On the other hand, the workforce will receive salaries -which in part will be spent locally and the federal and state governments will increase their revenues through taxation, and higher domestic oil supply will reduce imports. The indirect economic benefits estimated with the model are:

- Contribution to GDP: calculated by multiplying NSURM's estimation of the $ contribution to GDP for each barrel of light oil produced ($101.56/bbl) by the total output of the oil shale industry. Using a sectoral partial equilibrium model, we are not able to calculate the contribution to GDP relative to the oil price projections employed in this study (AEO 2009), which are considerably higher than the ones used by NSURM ($107/bbl versus $51/bbl, average real prices through 2030).

- Value of imports avoided: similar to the contribution to GDP, the value of imports avoided uses NSURM (2006) $ value per barrel produced ($25.39/bbl).

- Federal revenues: calculated by multiplying the operating result by 34%, the Federal corporate tax rate (Toman et al. 2008)

- State revenues: calculated by multiplying the operating result by 5%, the State corporate tax rate (Toman et al. 2008)

- No royalties or additional taxation, or credits, are considered in the model in its present state.

Major Assumptions Summary

- The construction of production capacity is assumed to take place based on NSURM's projections, reaching 1.5 million barrels per day by 2040. A one-year delay for commissioning and a 5 years delay in construction are considered.

- The capital life time is assumed to be 30 years (NSURM 2006) and its depreciation time is 20 years.

- The capital cost per barrel of production capacity is assumed to be constant over time - $80,000/bbl- in the baseline scenario (Utah Heavy Oil Program 2007).

- The variable costs accounted for in the model are: labor (wages), energy, water and CO_2 price.

- Revenues are generated from the sale of light oil only, as it is assumed that natural gas extracted during the production process is entirely used for internal power generation.

- Employment is disaggregated into two categories: direct and indirect. Direct employment includes construction of oil shale plants/facilities and O&M jobs. Indirect employment includes all jobs created by, and in support of, the oil shale industry (e.g. restaurants and housing).

- Both labor requirement for construction and O&M are assumed to be constant over time and are based on studies from the University of Utah (Utah Heavy Oil Program 2007).

- Salaries are assumed to adjust to the national average for the oil and gas business over a period of 30 years.

- The return on investment is assumed to be 15% in the baseline scenario (NSURM 2006).

- Indirect economic benefits of oil shale production are represented as: contribution to GDP and value of imports avoided (based on NSURM analysis, and public revenues -federal and state- (based on information provided by RAND (Toman 2008).

Agriculture

The purpose of the *Agriculture* module is to calculate and represent agriculture water demand and potential impacts of climate change on yield, land use and water requirements. Currently, only water demand is calculated. A climate change component will be added to the model at a later time. Agriculture water demand is exogenous at this time and uses assumptions and projections obtained from BLM (2008). Agriculture water demand is used in the *Water Sector* module.

Major Assumptions Summary

- Agriculture water demand is based on the assumption that there will be growing urbanization of irrigated lands in the studied region (BLM 2008) due to the development and expansion of the oil shale industry;

- Agriculture water demand is considered for the areas covered by the Colorado Basin, Uinta Basin and Green River Basin (BLM 2008)

Population and Residential Sector

The purpose of the *Population and Residential Sector* module is to calculate population growth in the studied geographical area as well as its water and electricity demand and CO_2 emissions generation. Total population in the *ReIMAE*, P_{tot}, is calculated as the sum of regional population without the oil shale contribution, P_{noOS}, and oil shale industry development contribution, P_{os}.

$$P_{tot}=P_{noOS}+P_{os} \tag{59}$$

The first term represents the population originally located in the geographical area considered and its longer term natural growth rate. How P_{noOS} changes in time depends on birth rate (P_b), death rate (P_d), and "other factor" rate (P_{ot}) and the value of the population in 2009. We calculate P_{noOS} in the following way:

$$\frac{d(P_{noOS})}{dt}=P_b(t)–ÐP_d(t)+P_{ot}(t) \tag{60}$$

Birth and death rates are calculated using historical data and projections from the United Nations Population Statistics Division (UN POP), mid-growth scenario. The “other factors" rate (P_{ot}) is calculated by subtracting the average U.S. net population growth from the historical data provided by BLM (2008) We assume that favorable economic conditions, or higher than average birth rates, had driven population growth in the region to be about 1% above the national average in the past, and we have no reasons to assume that this will not hold true in the future.

The second term includes population that moves to the area only due to the oil shale business; it represents the population working directly or indirectly for the oil shale business and its natural growth rate over time. How P_{os} changes in time depends on births rate, P_b^{os}, deaths rate, P_r^{os}, and a migration rate, P_r^{os}.

$$\frac{d(P_{os})}{dt} = P_b(t) - ÐP_r(t) + P_r^{os}(t) \tag{61}$$

We assume the third rate to be entirely driven by the oil shale business and can be either positive or negative, depending on the stage of development of the industry. P_m^{os}, imported from the *Oil Shale and Regional Economy Sector* module, is determined by the oil shale related employment, both direct (construction and O&M) and indirect. Here we account for the eventuality that some workers will move to the region with their family, adding a family multiplier of 1.1 (10%). The birth rate accounts for new born after people/families move to the oil shale area with a job in the oil shale business.

Energy and water demand, and emissions in the residential sector are calculated using total population, P_{tot} in the following way. Energy demand is give by:

$$E_{res}^{d} = P_{tot} * \delta \tag{62}$$

where δ represents per capita electricity demand, assumed to be equal to the average U.S. national data (AEO 2010). Analogously, water demand is calculate as follows:

$$w_{res}^{d} = P_{tot} * \zeta \tag{63}$$

where ζ represents per capita water demand, assumed to be equal to the average U.S. national data (DOE Fact Sheet). Finally, we determine CO_2 emissions, generated from electricity production and other fuels use, multiplying the total population by the per capita emission creation, μ, calculated using the national U.S. average (AEO 2010):

$$CO_2^{d,res} = P_{tot} * \mu. \tag{64}$$

Major Assumptions Summary

- Population birth and death rates, for both ROI and oil shale-related population, are exogenous and are taken from United Nations Population Division historical data and projections (UNPOP);

- The population stock of the ROI is assumed to be influenced by births, deaths and migration - driven by economic factors. The latter was calculated using BLM historical data (BLM);

- Electricity and water demand, and emissions are assumed to be driven by the population of the ROI and inputs are used on a per capita basis;

- Electricity and emissions per capita are based on national (US) averages and are calculated using EIA's Annual Energy Outlook (EIA);

- Water demand per capita is based on the national (US) average provided by DOE and it is assumed to remain constant in the future.

Commercial Sector

The purpose of the Commercial Sector module is to calculate electricity and water demand, as well as emissions, accounting for the expansion of the oil shale industry, of the commercial sector in the studied region. We assume that these three outputs are driven by the regional GDP. Energy and water demand, and emissions are calculated using endogenous GDP of the region of interest using calculations and exogenous, per dollar, demand factors. We determine the GDP for the region of interest (GDP_{reg}) as the sum of the GDP of the single states in the studied area (GDP_i $i=COL,WYO,UTAH$), multiplied by the share of the population residing in the area of the respective state (λ_i).

$$GDP_{reg}(t)=\sum_i GDP_i(t)*\lambda_i \tag{65}$$

The population shares of Colorado, Utah and Wyoming in the area analyzed are 4.81%, 5.52% and 17.73% respectively as reported by the U.S Bureau of Land Management report (BLM, 2008). For the single state GDP_i we applied the AEO (2010) national projections, which forecast a 2.5% GDP growth rate between 2009 and 2030. GDP_{reg} does not account for the contribution of the oil shale business (GDP_{uff})to the local economy. We determine this contribution separately and add it to the GDP_{reg} to obtain the total GDP (GDP_{tot}):

$$GDP_{tot}(t)=GDP_{reg}(t)+GDP_{uff}(t). \tag{66}$$

We calculate GDP_{uff} by multiplying the monetary contribution to GDP for each barrel produced[2] ($101.56/bbl as reported by NSURM (2006) multiplied by production capacity in place (80%) and under construction (20%). This formulation stems from the consideration that building an oil shale industry requires material, labor and energy inputs. While materials can be shipped to the construction site and energy can be delivered, workers will be brought to the construction site and neighboring areas, where they will likely stay for a few years. As a consequence, public infrastructure will need improvements and expansion, the public grid will need to be upgraded to adequately supply oil shale energy intensive operations, and housing units will be built. Furthermore, the workforce will receive salaries, which in part will be spent locally, the federal and state governments will increase their revenues through taxation, and higher

[2] Using a sectoral partial equilibrium model, we are not able to calculate the contribution to GDP relative to the oil price projections employed in this study (EAI 2009b), which are considerably higher than the ones used by NSURM (2006, SPE 2007): $107/bbl versus $51/bbl, respectively, average real prices through 2030.

domestic oil supply will reduce imports. All these factors, both in the construction and operation of the industry, will contribute to GDP.

Once we estimate the GDP_{reg}, we calculate energy and water demand and emission for the commercial sector as follows. Energy demand is given by:

$$E_c = GDP_{tot} * \Theta \tag{67}$$

where Θ is the electricity demand factor of GDP (i.e. electricity intensity of GDP) for the commercial sector, calculated using average U.S. national data (AEO 2010). Water demand for the commercial sector is calculated analogously:

$$w_c = GDP_{tot} * \psi \tag{68}$$

where ψ is the water demand factor of GDP (i.e. water intensity of GDP) for the commercial sector, calculated using average U.S. national data[3]. We determine the CO_2 emissions of the commercial sector, generated from electricity generation and other fuels use as follows:

$$CO_2^c = GDP_{tot} * \nu \tag{69}$$

where ν is the emission factor of GDP (i.e. carbon intensity of GDP) for the commercial sector, calculated using average U.S. national data (AEO 2010).

Major Assumptions Summary

- Electricity and water demand and emissions are assumed to be driven by the regional GDP;
- Electricity and emissions per unit of GDP are based on national (U.S.) averages and are calculated using EIA Annual Energy Outlook (AEO, 2010);
- Water demand per unit of GDP is based on the national (U.S.) average provided by USGS[4] and uses the 1995 to 2000 trend for future projections;
- The GDP of the region is calculated using historical State data from the Bureau of Economic Analysis (BEA 2009) adjusted using the share of population of the three states considered actually living in the region of interest (BLM 2008). Projections for baseline GDP growth are taken from the AEO (2010);
- The GDP of the region is positively impacted by the oil shale business (NSURM 2006).

[3] http://pubs.usgs.gov/circ/2004/circ1268/htdocs/table14.html

Industrial Sector

The purpose of the Industrial Sector module is to calculate electricity and water demand, as well as emissions, accounting for the expansion of the oil shale industry, of the industrial sector in the area of interest. As for the commercial sector, we assume that electricity and water demand, as well emissions, generated by the industrial sector are driven by the regional GDP, GDP_{ot}, calculated in the *Commercial Sector* module. Energy demand for the industrial sector is given by

$$E_c = GDP_{tot} * \Pi \tag{70}$$

where Π is the electricity demand factor of GDP (i.e. electricity intensity of GDP) for the industrial sector, calculated using average U.S. national data (AEO 2010). Water demand for the industrial sector is calculated analogously:

$$w_c = GDP_{tot} * \theta \tag{71}$$

where θ is the water demand factor of GDP (i.e. water intensity of GDP) for the industrial sector, calculated using average U.S. national data USGS[4]. We determine the CO_2 emissions of the industrial sector, generated from electricity generation and other fuels use as follows:

$$CO_2^c = GDP_{tot} * \varkappa \tag{72}$$

where κ is the emission factor of GDP (i.e. carbon intensity of GDP) for the industrial sector, calculated using average U.S. national data (AEO 2010).

Major Assumptions Summary

- Electricity and water demand, and emissions are assumed to be driven by the GDP of the region of interest;
- Electricity and emissions per unit of GDP are based on national (U.S.) averages and are calculated using EIA's Annual Energy Outlook (AEO 2010);
- Water demand per unit of GDP is based on the national (U.S.) average provided by USGS and uses the 1995 to 2000 trend for future projections.

Transportation

The purpose of the Transportation Sector module is to calculate and represent electricity demand and emissions generated, accounting for the expansion of the oil shale industry, of the transportation sector of the region of interest. As for commercial and industrial

[4] http://pubs.usgs.gov/circ/2004/circ1268/htdocs/table14.html

sectors, we assume that electricity demand and emissions of the transportation sector depends on the regional GDP.

Energy demand and emissions for the transportation sector are calculated as follows:

$$E_t = GDP_{tot} * \xi \tag{73}$$

where ξ is the electricity demand factor of GDP (i.e. electricity intensity of GDP) for the transportation sector, calculated using average U.S. national data (AEO 2010). GDP_{tot} is calculated and imported from the *Commercial* module. We determine the CO_2 emissions of the transportation sector, generated from electricity generation and other fuels use as follows:

$$CO_2^i = GDP_{tot} * \sigma \tag{74}$$

where σ is the emission factor of GDP (i.e. carbon intensity of GDP) for the transportation sector, calculated using average U.S. national data (AEO 2010).

Major Assumptions Summary

- Electricity and emissions are assumed to be driven by the GDP of the ROI;
- Electricity and emissions per unit of GDP are based on national (U.S.) averages and are calculated using EIA's Annual Energy Outlook (AEO 2010);
- The GDP of the region is calculated using historical State data from the Bureau of Economic Analysis (BEA 2009) adjusted using the share of population of the three states considered actually living in the region (BLM 2008). Projections for baseline GDP growth are taken from the AEO (AEO 2010);
- The GDP of the region is positively impacted by the oil shale business (NSURM 2006).

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