DESIGN OF A HIGH TEMPERATURE SUBSURFACE THERMAL ENERGY STORAGE SYSTEM

Qi Zheng
Clemson University, zheng5@g.clemson.edu

Follow this and additional works at: https://tigerprints.clemson.edu/all_theses
Part of the Geology Commons, Power and Energy Commons, and the Sustainability Commons

Recommended Citation
https://tigerprints.clemson.edu/all_theses/2008

This Thesis is brought to you for free and open access by the Theses at TigerPrints. It has been accepted for inclusion in All Theses by an authorized administrator of TigerPrints. For more information, please contact kokeefe@clemson.edu.
DESIGN OF A HIGH TEMPERATURE SUBSURFACE THERMAL ENERGY STORAGE SYSTEM

A Thesis
Presented to
the Graduate School of
Clemson University

In Partial Fulfillment
of the Requirements for the Degree
Master of Science
Hydrogeology

by
Qi Zheng
May 2014

Accepted by:
Dr. Ronald Falta, Committee Chair
Dr. Lawrence Murdoch
Dr. James Castle
ABSTRACT

Solar thermal energy is taking up increasing proportions of future power generation worldwide. Thermal energy storage technology is a key method for compensating for the inherent intermittency of solar resources and solving the time mismatch between solar energy supply and electricity demand. However, there is currently no cost-effective high-capacity compact storage technology available (Bakker et al., 2008). The goal of this work is to propose a high temperature subsurface thermal energy storage (HSTES) technology and demonstrate its potential energy storage capability by developing a solar-HSTES-electricity generation system. In this work, main elements of the proposed system and their related state-of-art technologies are reviewed. A conceptual model is built to illustrate the concept, design, operating procedure and application of such a system. A numerical base model is built within the TOUGH2-EOS1 multiphase flow simulator for the evaluation of system performance. Additional models are constructed and simulations are done to identify the effect of different operational and geological influential factors on the system performance.

Our work shows that when the base model is run with ten years operation of alternate injection and production processes - each for a month - with a thermal power input of 10.85 MW, about 83% of the injected thermal energy could be recovered within each working cycle from a stabilized HSTES system. After the final conversion into electrical energy, a relative (compared with the direct use of hot water) electricity generation efficiency of 73% is obtained. In a typical daily storage scenario, the simulated thermal storage efficiency could exceed 78% and the relative electricity
generation efficiency is over 66% in the long run. In a seasonal storage scenario, these two efficiencies reach 69% and 53% respectively by the end of the simulation period of 10 years.

Additional simulations reveal a thinner storage aquifer with a higher horizontal-to-vertical permeability ratio is favored by the storage system. A basin-shape reservoir is more favored than a flat reservoir, while a flat reservoir is better than a dome-shape reservoir. The effect of aquifer stratification is variable: it depends on the relative position of the well screen and the impermeable lenses within the reservoir. From the operational aspect, the well screen position is crucial and properly shortening the screen length can help heat recovery. The proportion of the injection/storage/recovery processes within a cycle, rather than their exact lengths, affects the storage efficiency. Reservoir preheating helps improve the energy storage efficiency for the first several cycles. However, it does not contribute much to the system performance in the long run. Simulations also indicate that buoyancy effect is of significant importance in heat distribution and the plume migration. Reducing the gravity override effect of the heat plume could be an important consideration in efficiency optimization.
ACKNOWLEDGMENTS

I would like to take this opportunity to thank all the supervising committee members, Dr. Ronald Falta, Dr. James Castle and Dr. Lawrence Murdoch, for their time, guidance and support throughout the course of this work. I would especially like to acknowledge Dr. Falta for his knowledge, wisdom, great patience and willingness to help. I also want to thank Dr. Falta for providing me the opportunity and financial support to work on such an interesting project.

The work presented here would not have been possible without the love and support of my family. Specifically, I want to thank my parents. I would not have made it this far without them.

Finally, I would like to express gratitude to Mr. Zhou, for his understanding, continuous support from every aspect, and the encouragement during my time here.
# TABLE OF CONTENTS

<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>TITLE PAGE</td>
<td>i</td>
</tr>
<tr>
<td>ABSTRACT</td>
<td>ii</td>
</tr>
<tr>
<td>ACKNOWLEDGMENTS</td>
<td>iv</td>
</tr>
<tr>
<td>TABLE OF CONTENTS</td>
<td>v</td>
</tr>
<tr>
<td>LIST OF TABLES</td>
<td>vi</td>
</tr>
<tr>
<td>LIST OF FIGURES</td>
<td>vii</td>
</tr>
<tr>
<td>1 INTRODUCTION</td>
<td>1</td>
</tr>
<tr>
<td>2 TECHNOLOGY DESCRIPTION</td>
<td>7</td>
</tr>
<tr>
<td>2.1 Research Objectives</td>
<td>7</td>
</tr>
<tr>
<td>2.2 Technology Overviews</td>
<td>7</td>
</tr>
<tr>
<td>2.2.1 Solar Thermal Steam Generators</td>
<td>7</td>
</tr>
<tr>
<td>2.2.2 Groundwater Heat Storage Well</td>
<td>11</td>
</tr>
<tr>
<td>2.2.3 Electricity Generation Facility</td>
<td>12</td>
</tr>
<tr>
<td>3 EXISTING SOLAR THERMAL STORAGE METHODS</td>
<td>16</td>
</tr>
<tr>
<td>3.1 Main Concepts</td>
<td>16</td>
</tr>
<tr>
<td>3.2 Sensible TES Techniques</td>
<td>18</td>
</tr>
<tr>
<td>3.2.1 Water</td>
<td>18</td>
</tr>
<tr>
<td>3.2.2 Rock Beds/Gravel</td>
<td>22</td>
</tr>
<tr>
<td>3.2.3 Ground</td>
<td>23</td>
</tr>
<tr>
<td>3.2.4 Molten Salt</td>
<td>26</td>
</tr>
<tr>
<td>4 HSTES SYSTEM</td>
<td>31</td>
</tr>
<tr>
<td>4.1 Important Concepts of HSTES</td>
<td>31</td>
</tr>
<tr>
<td>4.1.1 Boiling Temperature and Hydrostatic Pressure</td>
<td>31</td>
</tr>
<tr>
<td>4.1.2 Storage Formation</td>
<td>32</td>
</tr>
<tr>
<td>4.1.3 Location</td>
<td>33</td>
</tr>
</tbody>
</table>
Table of Contents (Continued)

<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>4.1.4 Energy Conversion</td>
<td>36</td>
</tr>
<tr>
<td>4.2 Learning from ATES and Geological CO₂ Sequestration</td>
<td>39</td>
</tr>
<tr>
<td>4.2.1 CO₂ sequestration</td>
<td>39</td>
</tr>
<tr>
<td>4.2.2 ATES</td>
<td>40</td>
</tr>
<tr>
<td>5 BASE CASE MODEL</td>
<td>42</td>
</tr>
<tr>
<td>5.1 Overview</td>
<td>42</td>
</tr>
<tr>
<td>5.2 Conceptual Model</td>
<td>43</td>
</tr>
<tr>
<td>5.2.1 Geographical Setting</td>
<td>43</td>
</tr>
<tr>
<td>5.2.2 Conceptual Model</td>
<td>46</td>
</tr>
<tr>
<td>5.3 Operating Procedure</td>
<td>49</td>
</tr>
<tr>
<td>5.4 Numerical Model Set-up</td>
<td>52</td>
</tr>
<tr>
<td>5.5 Simulation and Analyses</td>
<td>57</td>
</tr>
<tr>
<td>5.5.1 Water Production Driving Force</td>
<td>57</td>
</tr>
<tr>
<td>5.5.2 Simulation and Results</td>
<td>62</td>
</tr>
<tr>
<td>5.5.3 Wellbore Heat Loss</td>
<td>71</td>
</tr>
<tr>
<td>5.5.4 Comparing HSTES to Other Existing Energy Storage Methods</td>
<td>74</td>
</tr>
<tr>
<td>6 SYSTEM CHARACTERIZATION</td>
<td>77</td>
</tr>
<tr>
<td>6.1 System Performance under Different Injection Temperatures</td>
<td>77</td>
</tr>
<tr>
<td>6.2 System Performance in Short-term and Long-term Storages</td>
<td>79</td>
</tr>
<tr>
<td>7 STUDY OF INFLUENTIAL FACTORS</td>
<td>85</td>
</tr>
<tr>
<td>7.1 Scenario 1: Effect of Screen Location</td>
<td>87</td>
</tr>
<tr>
<td>7.2 Scenario 2: Effect of Cycle Length and I/S/P Proportion</td>
<td>90</td>
</tr>
<tr>
<td>7.3 Scenario 3: Effect of Preheating</td>
<td>92</td>
</tr>
<tr>
<td>7.4 Scenario 4: Effect of Storage Formation Thickness</td>
<td>94</td>
</tr>
<tr>
<td>7.5 Scenario 5: Effect of Permeability Anisotropy</td>
<td>97</td>
</tr>
<tr>
<td>7.6 Scenario 6: Effect of Storage Formation Shape</td>
<td>99</td>
</tr>
</tbody>
</table>
Table of Contents (Continued)

<table>
<thead>
<tr>
<th>Section</th>
<th>Title</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>7.7</td>
<td>Scenario 7: Effect of Stratification</td>
<td>103</td>
</tr>
<tr>
<td>7.7.1</td>
<td>Stratification in a Half Screened System</td>
<td>103</td>
</tr>
<tr>
<td>7.7.2</td>
<td>Stratification in a Fully Screened System</td>
<td>107</td>
</tr>
<tr>
<td>8</td>
<td>SUMMARY</td>
<td>110</td>
</tr>
<tr>
<td>9</td>
<td>CLOSING</td>
<td>113</td>
</tr>
<tr>
<td></td>
<td>REFERENCE</td>
<td>116</td>
</tr>
</tbody>
</table>
LIST OF TABLES

Table 1: Comparing renewable (shown as yearly potential) and finite (shown as total recoverable reserves) planetary energy reserves (Terawatt-years), and world’s annual consumption (Terawatt-years) ................................................................. 2

Table 2: Characteristics of current concentrating solar power (CSP) technologies used in power plants ................................................................. 10

Table 3: Existing and under-construction concentrated solar thermal power plants with thermal energy storage systems ....................... 29

Table 4: Solar thermal plants in the United States ........................................... 34

Table 5: Base case model dimensions and general parameters .............................. 55

Table 6: Material properties for the base case numerical model ................................ 56

Table 7: Vertical discretization of the base case numerical model ....................... 56

Table 8: Comparison of current electricity storage methods .................................. 75

Table 9: Model settings for different cases in 7 scenarios .................................... 86

Table 10: Operation settings for Cases 2, 3, 4 and the base case ............................ 90
LIST OF FIGURES

Figure 1: Main components and work flow for a solar thermal electricity generation system with the high temperature subsurface thermal energy storage design .......................................................... 5

Figure 2: Four types of solar collecting systems in use: a. Parabolic Trough; b. Linear Fresnel; c. Parabolic Dish; d. Solar Tower ...................................................................................................................................... 9

Figure 3: Schematic Profile of the ground thermal well ......................................................................................... 12

Figure 4: Single flash steam power conversion system scheme ................................................................. 15

Figure 5: Binary power conversion system scheme ...................................................................................... 15

Figure 6: A simple scheme of hot water tank design ................................................................................... 19

Figure 7: Principle ATES configuration ........................................................................................................ 20

Figure 8: Solar pond structure .................................................................................................................. 21

Figure 9: Cross-section of the gravel/water storage unit in Steinfurt .................................................. 22

Figure 10: Two principle borehole thermal energy storage system designs ..................................................... 24

Figure 11: Three basic types of borehole heat exchangers ........................................................................ 24

Figure 12: The aerial view of a borehole thermal energy storage (BTES) system .................................................. 25

Figure 13: Simplified scheme of a solar power plant with direct molten salt storage system .................................................. 27

Figure 14: Simplified scheme of a solar power plant with indirect molten salt storage system ............................................... 27

Figure 15: Boiling temperature of water as a function of underground depth ...................................................... 32
List of Figures (Continued)

<table>
<thead>
<tr>
<th>Figure</th>
<th>Description</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>16</td>
<td>Heat engine efficiency as a function of fluid temperature, showing the theoretic maximum engine conversion efficiency (Carnot efficiency and CA efficiency, respectively) under different working fluid temperatures (assume $T_{\text{sink}} = 25^\circ\text{C}$)</td>
<td>39</td>
</tr>
<tr>
<td>17</td>
<td>Density of saturated liquid water is a function of temperature</td>
<td>48</td>
</tr>
<tr>
<td>18</td>
<td>Schematic base case conceptual model</td>
<td>48</td>
</tr>
<tr>
<td>19</td>
<td>Solar thermal power generation and energy demand of the facility base in the base case scenario</td>
<td>50</td>
</tr>
<tr>
<td>20</td>
<td>Typical power generation from a solar field within a day</td>
<td>50</td>
</tr>
<tr>
<td>21</td>
<td>Illustration of the operating procedure in the base case model</td>
<td>52</td>
</tr>
<tr>
<td>22</td>
<td>Base case numerical model scheme (radial cross-sectional profile)</td>
<td>54</td>
</tr>
<tr>
<td>23</td>
<td>Wellbore grid profile showing the setting of DELV condition at the wellhead</td>
<td>60</td>
</tr>
<tr>
<td>24</td>
<td>Recovery flow rate under different outlet pressures with $PI = 2 \times 10^{12}$ m$^3$</td>
<td>61</td>
</tr>
<tr>
<td>25</td>
<td>Recovery flow rate under different outlet pressures with $PI = 5 \times 10^{12}$ m$^3$</td>
<td>62</td>
</tr>
<tr>
<td>26</td>
<td>Truncated radial cross-sections showing evolution of the hot zone around the well: Left column shows the temperature distribution after the injection period and right column after the recovery period within the same cycle. Pictures in the same column compare hot zone profiles at the same stage of different cycles.</td>
<td>64</td>
</tr>
</tbody>
</table>
List of Figures (Continued)

<table>
<thead>
<tr>
<th>Figure</th>
<th>Description</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>27</td>
<td>Formation temperature distribution and evolution around the wellbore for the base case model. (Rescaled with a horizontal exaggeration factor of 25)</td>
<td>66</td>
</tr>
<tr>
<td>28</td>
<td>Averaged efficiencies for each cycle over 60 cycles (10 years) with a preheating time of 2 months</td>
<td>71</td>
</tr>
<tr>
<td>29</td>
<td>Thermal energy storage efficiency plots comparing system performance with and without the wellbore based on the base case model</td>
<td>74</td>
</tr>
<tr>
<td>30</td>
<td>Thermal energy storage efficiency of cases with different injection temperature</td>
<td>78</td>
</tr>
<tr>
<td>31</td>
<td>Engine efficiency and relative electricity generation efficiency of the storage system under different injection temperatures</td>
<td>79</td>
</tr>
<tr>
<td>32</td>
<td>Energy efficiency of the daily I-S-P-S cyclic case</td>
<td>81</td>
</tr>
<tr>
<td>33</td>
<td>Thermal energy storage efficiency plot as a function of time for the seasonal storage case with a ten-year time span</td>
<td>84</td>
</tr>
<tr>
<td>34</td>
<td>Cross-sectional profiles showing the evolution of the heat plume within the</td>
<td>84</td>
</tr>
<tr>
<td>35</td>
<td>A screen location scheme: cross-sectional profiles showing the design of both half screened and fully screened cases</td>
<td>88</td>
</tr>
<tr>
<td>36</td>
<td>Thermal energy storage efficiency plots for Scenario 1: comparing system performance between the half screened and the fully screened case.</td>
<td>89</td>
</tr>
<tr>
<td>37</td>
<td>Reservoir cross-sectional profiles at the end of the injection and production processes of the 60th cycle showing the difference in two cases</td>
<td>89</td>
</tr>
<tr>
<td>38</td>
<td>Thermal energy storage efficiency for cases with different cycle lengths and I/S/P proportions.</td>
<td>91</td>
</tr>
</tbody>
</table>
List of Figures (Continued)

<table>
<thead>
<tr>
<th>Figure</th>
<th>Description</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>39</td>
<td>Thermal energy storage efficiency plots and cumulative thermal energy storage efficiency plots comparing system performance with and without preheating</td>
<td>93</td>
</tr>
<tr>
<td>40</td>
<td>Cross-sectional profiles showing the evolution of the heat plume in the reservoir in cases with and without preheating</td>
<td>93</td>
</tr>
<tr>
<td>41</td>
<td>Thermal energy storage efficiency as a function of time for cases with different storage formation thickness</td>
<td>96</td>
</tr>
<tr>
<td>42</td>
<td>Cross-sectional profiles showing different temperature distribution and evolution in reservoirs of different thicknesses</td>
<td>96</td>
</tr>
<tr>
<td>43</td>
<td>System thermal energy storage efficiency as a function of time under different horizontal anisotropy</td>
<td>98</td>
</tr>
<tr>
<td>44</td>
<td>Cross-sectional profiles showing different temperature distribution and evolution in storage reservoirs with different horizontal permeability anisotropy factors</td>
<td>99</td>
</tr>
<tr>
<td>45</td>
<td>Schemes of three formation shapes: Vertical and radial cross-sections illustrate the construction of these formation shapes in the models</td>
<td>101</td>
</tr>
<tr>
<td>46</td>
<td>Thermal energy storage efficiency as a function of time for cases with different storage formation shape</td>
<td>102</td>
</tr>
<tr>
<td>47</td>
<td>Cross-sectional profiles showing different temperature distribution at the end of the 30th cycle for cases with different formation shape</td>
<td>103</td>
</tr>
<tr>
<td>48</td>
<td>Thermal energy storage efficiency as a function of time for cases with different stratification under scenario of half screen</td>
<td>105</td>
</tr>
<tr>
<td>49</td>
<td>Cross-sectional profiles showing different temperature distribution at the end of the injection and production period of the 30th cycle</td>
<td>106</td>
</tr>
</tbody>
</table>
List of Figures (Continued)

Figure 50: Thermal energy storage efficiency as a function of time for cases with different stratification under the scenario of full screen................................................................................................................................107

Figure 51: Cross-sectional profiles showing different temperature distribution at the end of the injection and production period of the 30th cycle for the fully screened cases with different stratification........................................................................................................109
1 INTRODUCTION

Fossil fuels including crude oil, coal and gas, play a crucial role in the global economy. The modern world relies on them to produce electricity for a variety of industrial and residential usage. However, they are finite and nonrenewable resources. While the supply is limited (Table 1), the world energy consumption is huge and continually growing. According to the report of EIA and DOE (2013), with world GDP rising by 3.6% per year, world energy use will grow by 56% between 2010 and 2040. Total world energy use will rise from 17.7 Twy (terawatt-years) in 2010 to 21.2 Twy in 2020 and up to 27.6 Twy in 2040.

Due to the perceived scarcity of fossil fuels, there has been continuous research over decades for the economic and efficient use of alternative energy. They are becoming even more popular in recent years due to the rise in the cost of fossil fuels, concerns about air pollution and global warming and the caution on nuclear power after the 2011 nuclear disaster at Fukushima, Japan. Being clean and abundant (Table 1), renewable power sources bring both environmental benefits and energy security.

Among the renewables, solar energy is the most abundant and accessible candidate. The amount of solar energy our earth receives from the sun in just one hour is already more than what we consume in the whole world for one year (Perez and Perez, 2009). Solar power is the only known candidate to have the technical potential to greatly exceed the present final energy consumption of non-renewable energies (Park et al., 2014). The potential of other individual renewable resources all seem to be limited to much lower values. Being a clean energy, it can also significantly reduce the greenhouse
gas emissions. Assessments reveal that the lifecycle greenhouse gas emission for typical solar PV electricity generation is averaged to be 49.9g CO\textsubscript{2}-eq/kWh (Nugent and Sovacool, 2014) while it is about 440g CO\textsubscript{2}-eq/kWh on average for natural gas power plants in US (Middleton and Eccles, 2013). On the other hand, given current policies and regulations, worldwide energy-related carbon dioxide emissions are projected to increase 46% by 2040, reaching 45 billion metric tons in 2040 (DOE, 2013). A sustainable, low-carbon future requires such renewable energy transition.

Table 1: Comparing renewable (shown as yearly potential) and finite (shown as total recoverable reserves) planetary energy reserves (Terawatt-years), and world’s annual consumption (Terawatt-years) [Source: Perez and Perez (2009); DOE (2013)]

<table>
<thead>
<tr>
<th></th>
<th>Renewable (Twy/year)</th>
<th>Finite (Twy)</th>
<th>World Energy Consumption (Twy)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Solar</td>
<td>33,000</td>
<td>Coal 900</td>
<td>2010 17.7</td>
</tr>
<tr>
<td>Wind</td>
<td>25-70</td>
<td>Petroleum 240</td>
<td>2030 21.2</td>
</tr>
<tr>
<td>OTEC[1]</td>
<td>3 -11</td>
<td>Natural Gas 215</td>
<td>2050 27.6</td>
</tr>
<tr>
<td>Biomass</td>
<td>2-6</td>
<td>Uranium 90-300</td>
<td></td>
</tr>
<tr>
<td>Hydro</td>
<td>3-4</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Geothermal</td>
<td>0.3-2</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tides</td>
<td>0.3</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

[1] OTEC: Ocean thermal energy conversion

However, just as for most other types of renewable energies, inherent intermittency makes achieving the potential of solar energy more difficult. Solar output varies throughout the day and through the seasons, and is affected by weather conditions. The bulk of solar power is produced during summer, whereas the electricity demand is
high in winter and summer. Throughout a day, the sunlight is most intensive and productive around midday while the peak electricity demand occurs in the evening during summer, and in both morning and evening during winter (Source: Pasic Power). The cost of generating, distributing and maintaining electricity by the utility companies during peak hours is higher than during non-peak periods (Agyenim et al., 2010). Currently, most “peak” loads in US are gas-fired because they are able to quickly ramp up and down generation. As a consequence, electricity generation is becoming one of the fastest growing uses of natural gas. Accordingly, many power companies have adopted “Time-of-Day” price plans, raising electricity rates during “on-peak” hours and rewarding customers with credits for “off-peak” use to reduce the peak stress. Hence, there is a great potential for effective energy storage systems that can shift excess power produced at times of low-demand, low-generation cost or from intermittent renewable energy sources for release at times of high-demand, high-generation cost or when the intermittent power source is cut off.

Dispatchable power generation could have more advantages when applied in developing countries. Most developing countries have rich renewable energy sources and relatively labor-intensive systems that could harness them. By developing appropriate energy storage methods, those countries could reduce their dependency on fossil fuels, creating energy supply structures that are less vulnerable to price rises in fuels (Martinot et al., 2002). The same thing applies to off-grid remote regions and isolated areas as well. In the case of scattered populations, extending the grid may not be an economic option. Local power production and mini-scale grids can provide a more sustainable and cost
effective alternative (Nieuwenhout et al., 2001). The increase in the continuity and dispatchability of electricity from renewable sources calls for effective energy storage.

Appropriate energy storage methods are not only pursued by power stations to serve the purpose of regular diurnal and seasonal buffers for dispatchable power generation but are also favored by public institutions and manufacturers as backups to energy supply disruption. Without them, power outages can cause severe consequences to places like hospitals or military bases. Grid energy disruptions, such as the one faced by the Japanese economy after the earthquake and tsunami in 2011, emphasize the need for reliable, hardened energy storage systems that can support large installations for a period of days or weeks. However, conventional backup power is limited and very expensive. For example, a cost effective grid scale energy storage system with the ability to provide 1000 megawatt-hours (MW-h) of electrical generation capacity would represent a significant breakthrough in energy security for installations of large institutions. This equates to delivery of 1.34 megawatt (MW) of electricity continuously over a one-month period (enough to support a town of ~3000 people). To generate this amount of electricity from diesel backup generators would require consumption of 90,000 gallons of diesel fuels.

In this study, we propose and demonstrate a high-temperature subsurface energy grid scale storage system: the high-temperature subsurface thermal energy storage (HSTES) system. This type of system could be used as a buffer for small to medium size solar power stations to match the intermittent production with grid demand. It could also serve as a backup source, even “strategic energy reserve” for a particular building, system,
or even an entire base or installation to maintain the critical functions of facilities there in the event of grid disruption. The system could store energy from traditional high-temperature solar collectors, other renewable sources, and eliminates the need for fossil fuel supply. Take the storage of solar thermal energy for example: the hot water heated by solar collectors can be injected through an underground well into a permeable confined formation, where it is stored. When electricity is needed, the hot water is recovered from the well and flashed into steam to drive a turbine. The steam is subsequently condensed and can be reused as the solar thermal absorbent medium in the solar collector field. The main components and basic work flow are illustrated in Figure 1. This energy production from hot water is identical to conventional geothermal power production, except in our case, the heat has been harvested from the sun. Once the desired amount of heat storage in the formation is obtained, the solar thermal system can be used to directly generate electricity, with only intermittent “topping off” of the subsurface heat storage system.

Figure 1: Main components and work flow for a solar thermal electricity generation system with the high temperature subsurface thermal energy storage design
Another advantage of the HSTES system is the reuse of unproductive geothermal wells. Although geothermal has many proven technologies, only one in five deep geothermal-exploration wells historically have become commercially viable (Taylor, 2007). For example, the Twentynine Palms Marine Corps Base in California drilled an exploratory 3000-foot-deep well in 2011, in order to evaluate the geothermal energy potential. Unfortunately, the downhole temperature in this well was only about 90°C, which is too low to support geothermal production of electricity. However, these kinds of wells would likely be ideal for our proposed technology, where we would seek to increase the water temperature up to levels where electricity could be efficiently produced.
2 TECHNOLOGY DESCRIPTION

2.1 Research Objectives

By conducting detailed research, we want to:

1) Illustrate the complete process from solar energy collecting, to subsurface solar thermal energy storage, through final power generation;

2) Provide the technology options for the major components of such a system (solar thermal systems, groundwater heat wells, and electricity generation equipment);

3) Compare energy storage efficiency to conventional alternatives, such as stored diesel fuel, pumped water, batteries, or compressed air systems;

2.2 Technology Overviews

The proposed system will have three main elements: high temperature solar thermal steam generators, a groundwater heat storage well and the solar thermal electricity generation facility. All three components are mature with a great amount of practical experience. Little to no new technology will be required to enable a HSTES system.

2.2.1 Solar Thermal Steam Generators

Solar collectors are used to gather the solar energy, transform its radiation into heat, and then transfer that heat to a fluid. There are mainly four types of solar collecting systems in use. Parabolic trough technology is currently the most commercially mature large-scale solar power technology (Price et al., 2002).

1) Parabolic Trough Technology:
The parabolic trough collectors use a curved, mirrored trough to reflect the direct solar radiation onto a receiver tube containing a heat transfer fluid placed in the trough’s focal line (Figure 2a). The troughs are designed to be able to track the sun along one axis (Fernández-García et al., 2010; Price et al., 2002; Yogi Goswami, 1998).

2) Linear Fresnel technology:

Linear Fresnel reflectors (Figure 2b) make use of the Fresnel lens effect which enables the reflecting mirrors to have large apertures and short focal lengths, reducing the amount of material needed. Long, flat or slightly curved mirrors focus sunlight onto a linear absorber running across all the reflectors’ common focal points (Mills and Morrison, 2000). Working thermal fluid is thus heated in the absorber. The Linear Fresnel technology is a competitive alternative to parabolic troughs. Its advantages include simplified plant design and minimized internal energy losses. Also, its lower structural costs and the feature of low wind loads have reduced the investment and maintenance costs, respectively (Häberle et al., 2006).

3) Parabolic Dish Technology:

Within a Parabolic dish collector system, small parabolic dishes form a large overall dish-shape collector (Figure 2c). All these small dishes concentrate solar energy at a single focal point. A stirling engine coupled to a dynamo is placed at the focus to convert energy adsorbed into electricity directly (Yogi Goswami, 1998).

4) Solar Power Tower:

A significant advantage of central solar tower systems comparing with linear systems is their ability to produce high temperature fluid or steam. In such a system,
well-arranged flat heliostats (sun-tracking mirrors) reflect sunlight right on to the receiver located on the top of the tower (Figure 2d). The working fluid in the receiver is thus heated and will be used to generate electricity later (Segal and Epstein, 2001; Yogev et al., 1998; Yogi Goswami, 1998).

Figure 2: Four types of solar collecting systems in use: a. Parabolic Trough; b. Linear Fresnel; c. Parabolic Dish; d. Solar Tower [Modified from Quaschning (2003)]

Table 2 provides the characteristics and performance data for the four main types of concentrating solar power (CSP) technologies.
Table 2: Characteristics of current concentrating solar power (CSP) technologies used in power plants [Data source: Müller-Steinhagen and Trieb (2004); Trieb (2009)]

<table>
<thead>
<tr>
<th>Concentration Method</th>
<th>Line Concentrating System</th>
<th>Point Concentrating System</th>
</tr>
</thead>
<tbody>
<tr>
<td>Solar Field Type</td>
<td>Parabolic Trough</td>
<td>Linear Fresnel</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Central Receiver</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Parabolic Dish</td>
</tr>
<tr>
<td>State of the Art</td>
<td>commercial</td>
<td>pre-commercial</td>
</tr>
<tr>
<td></td>
<td>demonstrated</td>
<td>demonstrated</td>
</tr>
<tr>
<td>Typical Unite Size (MW)</td>
<td>10-200</td>
<td>10-150</td>
</tr>
<tr>
<td></td>
<td>0.01-0.4</td>
<td>800-900</td>
</tr>
<tr>
<td>Operating Temperature (°F)</td>
<td>390-550</td>
<td>550-1000</td>
</tr>
<tr>
<td></td>
<td>1000-3000</td>
<td></td>
</tr>
<tr>
<td>Concentration</td>
<td>70-80</td>
<td>25-100</td>
</tr>
<tr>
<td></td>
<td>300-1000</td>
<td>1000-3000</td>
</tr>
<tr>
<td>Heat Transfer Fluid</td>
<td>synthetic oil, water/steam</td>
<td>synthetic oil, water/steam</td>
</tr>
<tr>
<td></td>
<td>air, molten salt, water/steam</td>
<td>Air</td>
</tr>
<tr>
<td>Themodynamic Power Cycle</td>
<td>Rankine</td>
<td>Rankine</td>
</tr>
<tr>
<td></td>
<td>Brayton, Rankine</td>
<td>Stirling, Brayton</td>
</tr>
<tr>
<td>Power Unit</td>
<td>steam turbine</td>
<td>steam turbine</td>
</tr>
<tr>
<td></td>
<td>gas turbine, steam turbine</td>
<td>Sterling engine</td>
</tr>
<tr>
<td>Cost of Solar Field ($/m²)</td>
<td>275-350</td>
<td>200-275</td>
</tr>
<tr>
<td></td>
<td>350-400</td>
<td>&gt; 475</td>
</tr>
<tr>
<td>Land Use (m²·MW·h⁻¹·y⁻¹)</td>
<td>6-8</td>
<td>4-6</td>
</tr>
<tr>
<td></td>
<td>8-12</td>
<td>8-12</td>
</tr>
<tr>
<td>Capacity Factor [¹]</td>
<td>24% (d)</td>
<td>25-70% (p)</td>
</tr>
<tr>
<td></td>
<td>25-70% (p)</td>
<td>25-70% (p)</td>
</tr>
<tr>
<td></td>
<td>25% (p)</td>
<td></td>
</tr>
<tr>
<td>Peak Solar Efficiency [²]</td>
<td>21% (d)</td>
<td>20% (p)</td>
</tr>
<tr>
<td></td>
<td>20% (p)</td>
<td>20% (d)</td>
</tr>
<tr>
<td></td>
<td>35% (p)</td>
<td>29% (d)</td>
</tr>
<tr>
<td>Annual Solar Efficiency</td>
<td>10-15% (d)</td>
<td>8-10% (d)</td>
</tr>
<tr>
<td></td>
<td>8-15% (p)</td>
<td>15-25% (p)</td>
</tr>
<tr>
<td></td>
<td>16-18% (d)</td>
<td></td>
</tr>
<tr>
<td>Thermal Cycle Efficiency</td>
<td>30-40% ST</td>
<td>30-40% ST</td>
</tr>
<tr>
<td></td>
<td>30-40% ST</td>
<td>30-40% ST</td>
</tr>
<tr>
<td></td>
<td>45-55% CC</td>
<td>20-30% GT</td>
</tr>
<tr>
<td>Experience</td>
<td>high</td>
<td>low</td>
</tr>
<tr>
<td></td>
<td>moderate</td>
<td>moderate</td>
</tr>
<tr>
<td>Reliability</td>
<td>high</td>
<td>unknown</td>
</tr>
<tr>
<td></td>
<td>moderate</td>
<td>High</td>
</tr>
<tr>
<td>Integration to the Environment</td>
<td>difficult</td>
<td>simple</td>
</tr>
<tr>
<td></td>
<td>moderate</td>
<td>Moderate</td>
</tr>
<tr>
<td>Construction Requirements</td>
<td>demanding</td>
<td>demanding</td>
</tr>
<tr>
<td></td>
<td>demanding</td>
<td>Simple</td>
</tr>
<tr>
<td>Operating Requirements</td>
<td>demanding</td>
<td>demanding</td>
</tr>
<tr>
<td></td>
<td>Simple</td>
<td></td>
</tr>
</tbody>
</table>

(d) = demonstrated; (p) = projected; ST = steam turbine; GT = gas turbine; CC = combined cycle.

[¹] Capacity Factor = \( \frac{\text{solar operating hours per year}}{8760 \text{ hours per year}} \)

[²] Solar Efficiency = \( \frac{\text{net power generation}}{\text{incident beam radiation}} \)

In our system, we would use the Linear Fresnel Reflectors for relatively lower temperature (130°C-290°C) steam generation due to their significantly low cost and easy operation requirements and Parabolic Trough Reflectors for higher temperature (200°C-300°C) steam production.
There are several vendors available to provide this element. Take the Compact Linear Fresnel reflectors provided by Areva Solar for example, pressurized hot water could be generated directly from a one-pass water stream as the working fluid, or generated from heat transfer fluids and heat exchangers. The cycling water would be supplied from a groundwater supply well (resulting in no net water demand), or from waste water. The collectors can generate up to 2050 MWh of heat per acre, per year of collection (Source: Areva Solar webpage). Fluid temperatures up to 480°C are possible with this type of solar thermal system, with pressures up to 16.7 MPa (~1700 meters of water pressure).

2.2.2 Groundwater Heat Storage Well

In our thermal storage system, a groundwater well would need to be installed into a confined reservoir: an underground permeable stratum bounded by upper and lower impermeable layers. Such a deep formation under high hydrostatic pressure is like a naturally pressurized vessel which can be used to prevent the formation of steam vapor and maintain the temperature of the injected hot water. A schematic profile is provided in Figure 3 for the case of storing 250°C hot water. It is a single well system. The well is screened inside the aquifer and hot water is injected and recovered from the same well.

This element of the system is not difficult to obtain. The design requirements of such a well are very similar to those of a high-temperature geothermal well. Hence, a high-temperature geothermal well can be directly used as a groundwater heat storage well with slight modification.
A more detailed illustration of the storage mechanism and formation is provided in Section 5.

![Figure 3: Schematic Profile of the ground thermal well](image)

2.2.3 Electricity Generation Facility

Depending on the temperature, phases of water produced and chemical properties of the storage formation, there are three basic technologies available to convert the steam to electricity:

1) Flash Systems

High hydrostatic pressure keeps high-temperature water as liquid deep in the ground. However, as the hot water moves up along the wellbore during the producing
process, when the pressure drops to the vapor pressure, sudden boiling happens. Liquid water “flashes” to steam which increases the pressure until a dynamic equilibrium is achieved. Hence a mixture of liquid water and steam is produced from the well. In a Flash System, steam is separated from the mixture in a separator under a low pressure and then runs the turbine to power the generator. This is called a “Single Flash” system (DiPippo, 2012b). A “Double Flash” system includes two steam separators and turbines (DiPippo, 2012a). Steam flashes twice and turns two turbines. It is more effective than a single flash system and is used more widely today. A schematic illustration of a typical flash system is provided in Figure 4.

This type of system often applies when the source temperature is between 170°C and 260°C.

2) Binary Cycle Systems

For sources with temperatures lower than those in flash steam systems, a technology known as “Binary Cycle” (also known as “Rankine Cycle”) can make use of fluids of relatively lower temperatures (74°C-177°C) to produce electricity. These systems are now being used for low-temperature geothermal applications, such as a system in Alaska that generates 200 kW of electricity from a geothermal water stream with a temperature as low as 74°C (Taylor, 2007). A graphic illustration of a binary system is shown in Figure 5. It contains four main components: a boiler, a turbine, a cooling tower and a feed pump. Besides the geothermal fluid, it often uses an organic fluid with a much lower boiling point than water is used as the working fluid (hence, known as “organic” Rankine cycle). In such a system, the two fluids do not mix with
each other throughout the whole process. Heat transfers from the geothermal fluid (dominantly hot water, steam or the mixture of the two) to the working fluid (a hydrocarbon such as isopentane, or a refrigerant) through a heat exchanger where the working fluid flashes to vapor and drives the turbines. The cooled geothermal fluid is then injected back into the ground through another well at a different location so the cycle can begin anew. Theoretically, 100% of the geothermal fluid can be retrieved (Taylor, 2007). This closed cycle reduces the emissions to near zero and contributes to the conservation of the reservoir pressure, thereby extending project lifetime.

3) Combined Systems

To make use of a larger portion of the thermal energy, a flash/binary combined cycle is sometimes used. In such a system, geothermal fluid first flashes to generate the steam to drive the turbine. Then the low-pressure steam exiting the backpressure turbine is turbine is condensed in a binary system.

In our case, a flash system could be used if the temperature of fluid produced after storage is high and a binary system could be applied if the temperature is lower. Complex systems intergrading different processes can also be used. Once the commercial energy grid is disrupted, a self-sustaining system utilizing conventional geothermal energy technology could provide electrical power for a site (pending full system start-up, a small diesel or battery powered generator may be used to pump the hot water out of the heat storage well).
Figure 4: Single flash steam power conversion system scheme [Modified from Taylor (2007)]

Figure 5: Binary power conversion system scheme [Modified from Taylor (2007)]
3 EXISTING SOLAR THERMAL STORAGE METHODS

3.1 Main Concepts

One of the main issues impeding solar thermal technologies from fully achieving their potential is the development of efficient and cost-effective means for thermal storage. Before looking into the HSTES system we proposed, a brief review of the existing solar thermal storage methods is given in this section to introduce the concepts and techniques of solar thermal energy storage.

Current thermal energy storage (TES) methods are classified into three main categories according to different storage mechanisms: chemical heat storage, latent heat storage and sensible heat storage.

1) The chemical heat storage method makes use of the character of some chemicals that they can absorb/release a large amount of thermal energy when they break/form certain chemical bonds. It can be subdivided into chemical reactions method which stores heat in reversible reactions and thermo-chemical method which stores heat by an endothermic desorption process and release heat through an exothermic process (Pinel et al., 2011). Chemical storage has the highest storage capacity, but the problems such as the requirement of complicated reactors for specific chemical reactions, weak long-term durability (reversibility) and the uncertain stability of chemicals restrict its application (Tian and Zhao, 2013).

2) The latent heat storage (LHS) methods store energy in some kinds of materials with a high heat of fusion known as Phase Change Materials (PCM). This method takes advantage of the fact that at the fusion temperature, substances undergo a phase change
associated with a large amount of energy absorption/release without changes in temperature. The PCMs may undergo solid–solid, solid–liquid and liquid–gas phase transformations (Cárdenas and León, 2013). They are capable of storing and releasing large amounts of heat while they are melting and solidifying at a specific temperature. Research on PCM materials and storage design is increasing in interest in recent years because of its potential in improving energy storage efficiency and the fact that it can store and release thermal energy at nearly constant temperature (Aceves-Saborio et al., 1994). Since the phase-transition enthalpy of PCMs are usually much higher (100-200 times depending on the materials) than sensible heat (Tian and Zhao, 2013), latent heat storage usually has very high storage density. However, the weak heat transfer performance is a big limitation. The system usually needs enhancement in design through the application of fins, enhancing thermal conductivity, application of tube-in-shell TES technology, and application of micro-capsulation (Agyenim et al., 2009; Akgün et al., 2008).

Liu et al. (2012) provided a detailed review on storage materials and performance enhancement for high temperature PCM systems. In this review, inorganic salts and salt composites as well as metals and metal alloys used or with the potential to be used as PCMs are provided which could be referred to for more information.

3) Finally, the sensible heat storage method utilizes an increase or decrease of the storage material temperature. It stores heat as internal energy without phase change. It is usually much simpler and cheaper than other storage methods. According to Gil et al. (2010), current sensible heat storage materials have a wide range of working
temperatures (200°C-1200°C), and excellent thermal conductivities: 1.0 W/(m·K) to 7.0 W/(m·K) for sand-rock minerals, concrete and fire bricks, 37.0 W/(m·K) to 40.0 W/(m·K) for ferroalloy materials. However, they have a big disadvantage of low heat capacities, typically range from 0.56 kJ/(kg·°C) to 1.3 kJ/(kg·°C). This will result in huge storage units if they are constructed above ground.

Pinel et al. (2011) summarized the main sensible heat storage methods available today and categorize them by the different storage median they use: water, rock beds (gravel) and soil.

3.2 Sensible TES Techniques

3.2.1 Water

The simplest method is to use water itself as a heat storage medium directly. Because of its simplicity, cheap price and wide availability, there are a significant amount of published data on the design criteria for various water heat storage media (Abhat, 1980; Duffie et al., 1976; Garg et al., 1985; Wyman et al., 1980). Using heat-insulated water tanks is the most straightforward way. The water tank can either be an open system in which heat is transported along with water flowing through the tank or more commonly, a closed system in which heat is transferred between two separate (inside and outside) cycles through a heat exchanger. One such design is shown in Figure 6.
Aquifer thermal energy storage (ATES) systems make use of underground water and the substrate it occupies to store the thermal energy. They use groundwater for the heat transport into and out of an aquifer via a well doublet or a multi-well system. Aquifers hold great promise for underground energy storage. In many systems, the heat source for aquifer thermal energy storage (ATES) is solar collectors. Several large-scale projects related to low to medium temperature underground storage of waste heat from co-generation plants and incineration plants are in planning in Europe and the US (Sanner and Knoblich, 1998). As illustrated in Figure 7, its main components include surface facilities and two thermal wells. The basic working process is: during winter time, warm ground water is pumped out from a warm store region and is pumped through a heat exchanger to provide heat for residential space heating. Then the cooled water will be injected back into the specific region for cold storage in the aquifer. When hot summer comes, the stored cold water will be used to cool the space. The warmed water will be
injected to the underground warm store region in the aquifer. Hereby, a seasonal repeated cycle forms. ATES is a very promising technology today due to its high storage capacity. It is especially suitable for large scale and longtime storage and it has been successfully applied to a number of sites. Dincer and Rosen (2002) have provided a very comprehensive review to this technology. Other review of the state-of-the-art can be found in Kranz and Frick (2013); Lee (2010); Novo et al. (2010) and Paksoy et al. (2009). Some large scale ATES projects in practice are provided in the work of Desmedt et al. (2007); Paksoy et al. (2004); Vanhoudt et al. (2011) and Wigstrand (2010). However, currently proposed ATES technologies and projects in application or under construction are all relatively low temperature thermal energy storage systems and are not useful for electricity generation.

Figure 7: Principle ATES configuration [Modified from Andersson (2007)]
Surface water can also be used for thermal storage. Some natural or artificially constructed ponds (known as solar ponds) take advantage of a vertical salinity gradient to trap solar thermal energy at the bottom of the pond. As is shown in Figure 8, a solar pond is a pool of saltwater. Salt concentration is highest at the bottom and decreases upward. Such a gradient impedes heat convection in the pond and thus highly reduces heat loss to the atmosphere.

Most such water-storing methods are simple and cheap. However, they experience the problem of temperature limitations due to water’s low boiling point (100°C at the atmosphere pressure). This limits their applications in electricity generation. Except for the hot water/steam tank, water as the thermal storage medium, is mostly applied in low-to-medium temperature systems such as space heating and cooling.

![Solar pond structure](image)

Figure 8: Solar pond structure
3.2.2 Rock Beds/Gravel

Although gravel has a low specific heat, [dry gravel has a specific heat (C=0.92KJ/kg·°C) only about one fifths that of liquid water (C=4.19KJ/kg·°C)], the ability to work well at a high temperature makes it a possible option for thermal storage. In a typical rock bed storage system, high-temperature fluid circulates through a container filled with gravel (Figure 9). Heat transfers from the fluid to the rock bed during this process. The fluid medium can either be air or water. However, air is not a thermal energy storage medium thus results in more volume of rock bed required for storage, but it costs less (Dincer and Rosen, 2002). This type of system is suitable for short-time time heat storage, while for long-time storage, the space required is large and the heat loss will be significant.

![Figure 9: Cross-section of the gravel/water storage unit in Steinfurt](image-url)

Figure 9: Cross-section of the gravel/water storage unit in Steinfurt [Modified from Pfeil and Koch (2000)]
3.2.3 Ground

Ground can also be used to store thermal energy. A common means of ground source thermal energy storage is to insert tubes (vertical boreholes or horizontal pipes) in the ground and circulating hot water in the soils. Such system is also called the borehole thermal energy storage (BTES) system. In a BTES system, since heat is stored directly into the ground, the storage system does not have an exactly separated storage volume. The heat is transferred to the underground by means of conductive flow from a number of closely spaced boreholes (Pavlov and Olesen, 2011). Generally, boreholes are backfilled with high thermal conductivity materials (known as grouting materials) to provide good thermal contact with the surrounding soil and prevent contamination of the ground water.

There are two basic borehole designs: open system and closed system, as illustrated in Figure 10. In an open system, the injecting pipe has its opening near the bottom while the opening of the extraction pipe closes at the top. The two pipes do not connect to each other directly. The closed system uses u-pipes as heat exchangers. Fluid circulates in a closed loop.

The borehole can be equipped with different kinds of borehole heat exchangers, making the borehole act as a large heat exchanger between the system and the ground (Figure 11). The most common borehole heat exchanger is the U-tube. It can be further optimized to a more efficient multiple U-tube system. Heat is charged or discharged by these vertical borehole heat exchangers. At charging, the flow direction is from the center to the boundaries of the system to obtain high temperatures in the center and lower ones at the boundaries. At discharging the flow direction is reversed (Schmidt et al., 2004).
An aerial view of such a borehole thermal energy storage (BTES) system is shown in Figure 12. Heat or cold is delivered or extracted from the underground by circulating a fluid in a closed loop through the boreholes.

Figure 10: Two principle borehole thermal energy storage system designs

Figure 11: Three basic types of borehole heat exchangers

For ground thermal storage, systems of all sizes have been built, from a building scale to very large. The requirements of such a system are not restrict. The strata can be most type of soils and rocks and the depth has a wide range from 50 to 300 m. Also such
a can exist under a variety of land covers. It can serve the purpose of inter-seasonal heat transfer.

Another application of the ground in thermal energy storage is as the insulator for hot water tanks. Normally, underground hot water tanks have higher efficiency than surface tanks and require almost no surface land use.

However, although ground thermal storage method is a commercially mature technology, it is mainly applied in low-to-medium temperature water storage. Such systems are generally used to serve the purpose of space heating and cooling. To our knowledge, there is no ground thermal storage system applied in large-scale power generation so far.

Figure 12: The aerial view of a borehole thermal energy storage (BTES) system (After DLSC, available at http://www.dlsc.ca/)
3.2.4 Molten Salt

Molten salt could be used both as PCM as well as sensible TES material. At present, it is more commonly used as sensible thermal storage material in practice. Molten salt storage is a very important TES concept as well as a major storage trend in solar thermal power plants. For systems with temperature above 100°C, molten salts are attractive candidates for sensible heat storage in liquids. The major advantages of molten salts are high heat capacity, high density, high thermal stability, relatively low cost, high viscosity, nonflammability, and low vapor pressure (Bauer et al., 2013). In general, there is experience with molten nitrate salts from a number of industrial processes related to the heat treatment of metals and heat transfer fluid (HTF) usage. The use of molten salts or steam as a HTF and storage material at the same time eliminates the need for expensive heat exchangers. It allows the solar field to be operated at higher temperatures than current heat transfer fluids allow.

At present, the two-tank molten salt storage is the only commercially available technology for large thermal capacities being suitable for solar thermal power plants. There are two concepts of molten salt storage systems: direct molten salt storage system and indirect molten storage system. The direct system uses molten salt as both heat transfer fluid and heat storage medium as illustrated in Figure 13. Such a system is in use at Solar Tres, Archimede Sicily and some other solar thermal power plants. The other concept is the indirect system, which allows the separation of the storage medium and HTF via a heat exchanger. A simplified scheme of such an indirect system is illustrated in Figure 14. The two-tank active indirect molten salt storage system is widely used in
parabolic trough solar thermal plants such as Andasol, Arcosol 50, El Reboso III, and Manchasol-1. Table 3 provides more information on different thermal energy storage systems in existing and under-construction concentrated solar thermal power plants.

Figure 13: Simplified scheme of a solar power plant with direct molten salt storage system [Modified from Ortega et al. (2008)]

Figure 14: Simplified scheme of a solar power plant with indirect molten salt storage system [Modified from Pacheco et al. (2002)]
Besides the above most common sensible TES methods, there are also other methods and materials proposed, such as the direct storage of synthetic oil, storing in ionic liquids or storage in solid materials such as alumina, alloys and concrete.

Overall, although there are a great number of TES methods proposed and tested, some of them can only be used in systems of low-to-medium temperature, which are not suitable for the application in electrical power generation. Among the high temperature storage methods, oil storage can lead to dangerous fires. The major storage trend - molten salt- experiences the problem of unwanted freezing during operation as a result of their high freezing points. Other limitations might include relative high costs, corrosion, and the hygroscopic property of some salts (Bauer et al., 2013).

Cost-effective high temperature solid TES are demonstrated but have not been put in large scale power generation applications. At present, they have drawbacks of high cost, low efficiency, limited storage capacity and other problems depending on the material.
Table 3: Existing and under-construction concentrated solar thermal power plants with thermal energy storage systems [Modified from Liu et al. (2012)]

<table>
<thead>
<tr>
<th>Project and location</th>
<th>Total capacity (MWe)</th>
<th>Solar collecting technology</th>
<th>HTF in solar field</th>
<th>Storage concept</th>
<th>Storage capacity (MWh)</th>
<th>Full load storage time (h)</th>
<th>Storage material</th>
<th>Storage temp (°C)</th>
<th>Cold</th>
<th>Hot</th>
</tr>
</thead>
<tbody>
<tr>
<td>SEGS I-IX Mojave Desert, California, USA</td>
<td>354</td>
<td>Parabolic trough</td>
<td>Mineral oil (SEGS I); Synthetic oil (SEGS II-IX)</td>
<td>Two-tank active direct (SEGS I)</td>
<td>120</td>
<td>0.3</td>
<td>Mineral oil (SEGS I)</td>
<td>240</td>
<td>307</td>
<td></td>
</tr>
<tr>
<td>Andasol Andalusia, Spain</td>
<td>200 (4×50)</td>
<td>Parabolic trough</td>
<td>Synthetic oil</td>
<td>Two-tank active indirect</td>
<td>1010</td>
<td>5</td>
<td>28,500 tons molten salt</td>
<td>291</td>
<td>384</td>
<td></td>
</tr>
<tr>
<td>Extresol Torre de Miguel Sesmero, Spain</td>
<td>100 (2×50)</td>
<td>Parabolic trough</td>
<td>Synthetic oil</td>
<td>Two-tank active indirect</td>
<td>1010</td>
<td>10</td>
<td>28,500 tons molten salt</td>
<td>N.A.</td>
<td>N.A.</td>
<td></td>
</tr>
<tr>
<td>Nevada Solar One Boulder City, Nevada, USA</td>
<td>64</td>
<td>Parabolic trough</td>
<td>Synthetic oil</td>
<td>N.A.</td>
<td>32</td>
<td>0.5</td>
<td>N.A.</td>
<td>N.A.</td>
<td>N.A.</td>
<td></td>
</tr>
<tr>
<td>Arcosol 50 San José del Valle, Spain</td>
<td>50</td>
<td>Parabolic trough</td>
<td>Synthetic oil</td>
<td>Two-tank active indirect</td>
<td>1010</td>
<td>20</td>
<td>28,500 tons molten salt</td>
<td>N.A.</td>
<td>N.A.</td>
<td></td>
</tr>
<tr>
<td>La Florida Badajoz, Spain</td>
<td>50</td>
<td>Parabolic trough</td>
<td>Synthetic oil</td>
<td>Two-tank active indirect</td>
<td>1010</td>
<td>20</td>
<td>29,000 tons molten salt</td>
<td>N.A.</td>
<td>N.A.</td>
<td></td>
</tr>
<tr>
<td>El Reboso III Sevilla, Spain</td>
<td>50</td>
<td>Parabolic trough</td>
<td>Synthetic oil</td>
<td>Two-tank active indirect</td>
<td>116</td>
<td>2.3</td>
<td>Molten salt</td>
<td>N.A.</td>
<td>N.A.</td>
<td></td>
</tr>
<tr>
<td>La Dehesa La Garrovilla, Spain</td>
<td>50</td>
<td>Parabolic trough</td>
<td>Synthetic oil</td>
<td>Two-tank active indirect</td>
<td>1010</td>
<td>20</td>
<td>29,000 tons molten salt</td>
<td>N.A.</td>
<td>N.A.</td>
<td></td>
</tr>
<tr>
<td>Manchasol-1 Alcazar de San Juan, Spain</td>
<td>50</td>
<td>Parabolic trough</td>
<td>Synthetic oil</td>
<td>Two-tank active indirect</td>
<td>375</td>
<td>7.5</td>
<td>28,500 tons molten salt</td>
<td>N.A.</td>
<td>N.A.</td>
<td></td>
</tr>
<tr>
<td>Archimede Sicily, Italy</td>
<td>5</td>
<td>Parabolic trough</td>
<td>Molten salt</td>
<td>Two-tank active direct</td>
<td>100</td>
<td>20</td>
<td>1580 tons molten salt</td>
<td>N.A.</td>
<td>N.A.</td>
<td></td>
</tr>
<tr>
<td>Puerto Errado 1 Calasparra, Spain</td>
<td>1.4</td>
<td>Linear Fresnel</td>
<td>Water</td>
<td>Single-tank (thermocline)</td>
<td>N.A.</td>
<td>N.A.</td>
<td>N.A.</td>
<td>N.A.</td>
<td>N.A.</td>
<td></td>
</tr>
<tr>
<td>Puerto Errado 2 Calasparra, Spain</td>
<td>30</td>
<td>Linear Fresnel</td>
<td>Water</td>
<td>Single-tank (thermocline)</td>
<td>N.A.</td>
<td>N.A.</td>
<td>N.A.</td>
<td>N.A.</td>
<td>N.A.</td>
<td></td>
</tr>
<tr>
<td>Gemasolar (Solar Tres) Fuente de Andalucía, Spain</td>
<td>15</td>
<td>Power Tower</td>
<td>Molten salt</td>
<td>Two-tank active direct</td>
<td>600</td>
<td>40</td>
<td>6250 tons molten salt</td>
<td>290</td>
<td>565</td>
<td></td>
</tr>
<tr>
<td>Planta Solar 10 Sevilla, Spain</td>
<td>11</td>
<td>Power Tower</td>
<td>Water</td>
<td>Active direct</td>
<td>20</td>
<td>1.8</td>
<td>Pressured water</td>
<td>285°C at 50 bar</td>
<td>250-300</td>
<td></td>
</tr>
<tr>
<td>Planta Solar 20 Sevilla, Spain</td>
<td>20</td>
<td>Power Tower</td>
<td>Water</td>
<td>Active direct</td>
<td>N.A.</td>
<td>N.A.</td>
<td>Steam-ceramic</td>
<td>N.A.</td>
<td>N.A.</td>
<td></td>
</tr>
</tbody>
</table>
4 HSTES SYSTEM

4.1 Important Concepts of HSTES

4.1.1 Boiling Temperature and Hydrostatic Pressure

A high temperature subsurface thermal energy storage (HSTES) system stores liquid phase hot water in subsurface reservoir for a finite period of time to be subsequently withdrawn and utilized in electrical power generation on demand or for other potential industrial processes. The key feature of HSTES is to utilize the hydrostatic pressure which is a function of depth under the water table. Since the hydrostatic pressure increases with the depth while the boiling point of water increases with the increase in pressure, there is a corresponding relation between the boiling point of water and the depth underneath the water table: the boiling temperature increases with increasing depth, as is illustrated in Figure 15. For example, if we want to store pressurized water of 250°C in the ground, the target formation should located at least 400 meters below the water table to allow a minimum hydrostatic pressure of 40 bars above the screened portion of the well to prevent the onset of boiling. Similarly, at a depth of 1km below the water table, the hydrostatic pressure could keep 300°C water in liquid phase.

A key feature of this method is that it keeps hot water above 100°C (boiling temperature at the atmosphere pressure) in the liquid phase. The main advantage to store this thermal energy as hot liquid water rather than steam vapor is the ease of containment and small volume required for storage, which reduces energy loss in the reservoir.
4.1.2 Storage Formation

To reduce heat loss under free convection, sandwich-like formations below the required depth are selected for heat storage. This type of formation would consist of a permeable layer (e.g., a sedimentary stratum) bounded by two impermeable strata (confining layers). A groundwater well would be installed into the permeable layer with screen open to the permeable storage formation (reservoir) for hot water injection and recovery.
4.1.3 Location

The HSTES system could be constructed at a variety of sites. For the application in solar power generation, two key factors that should be considered are suitable geology and abundant solar resource.

1) Solar resource

Overall, the United States has abundant solar resources. Solar insolation in the southwestern US is excellent, equivalent to that of Africa (Bugaje, 2006) and Australia (Hutchinson et al., 1984), which contain the best solar resources in the world. Among the three countries with most industrialized solar power generation in the world at present (US, Germany and Spain), the majority of the States has better solar resource than Spain which is considered the best in Europe, and is much higher than Germany (Price, 2010). According to the solar technologies market report of DOE (Price, 2010), the solar insolation levels in US range from about 1,250-2,500 kWh/m²/year. The variation of solar resource only has a factor of 2, which is relatively homogeneous compared to other renewable resources. Overall, a large portion of the United States has abundant solar resources and could meet the first requirement of the solar-hybrid HSTES system. California, Nevada, Texas, Utah, Colorado and Florida are most favorable for the system’s development. Currently, most US solar thermal power plants are concentrated in the southwest (Table 4).
Table 4: Solar thermal plants in the United States [Modified from Tian and Zhao (2013)]

<table>
<thead>
<tr>
<th>Capacity (MW)</th>
<th>Name</th>
<th>Location</th>
<th>Solar collecting technology</th>
<th>Heat transfer fluid</th>
<th>Thermal storage</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>400</td>
<td>Ivanpah solar power facility</td>
<td>San Bernardino County, CA</td>
<td>Solar power tower</td>
<td>Water (249°C–566°C)</td>
<td>No storage, using natural gas as backup</td>
<td>3 units: Ivanpah 1, 2 and 3. Ivanpah 1 and 2: 100 MW each. Ivanpah 3: 200 MW; completed in 2013</td>
</tr>
<tr>
<td>354</td>
<td>SEGS I-IX</td>
<td>Mojave Desert, CA</td>
<td>Parabolic trough</td>
<td>Mineral oil (SEGS I)</td>
<td>Two-tank active direct storage (SEGS I)</td>
<td>9 units, completed in 1984</td>
</tr>
<tr>
<td>280</td>
<td>Solana generating station</td>
<td>West of Gila Bend, AZ</td>
<td>Parabolic trough</td>
<td>Material: N.A. up to 371°C</td>
<td>6 h heat storage molten salts</td>
<td>Completed in 2013</td>
</tr>
<tr>
<td>250</td>
<td>Genesis solar</td>
<td>Blythe, CA</td>
<td>Parabolic trough</td>
<td>Therminol VP-1; up to 393°C</td>
<td>No storage, using natural gas as backup</td>
<td>2 units: 125 MW each, under construction</td>
</tr>
<tr>
<td>75</td>
<td>Martin next generation solar energy center</td>
<td>Florida</td>
<td>Parabolic trough, ISCC</td>
<td>Thermal oil</td>
<td>N.A.</td>
<td>Integrated Solar Combined Cycle, completed in 2010</td>
</tr>
<tr>
<td>64</td>
<td>Nevada solar one</td>
<td>Boulder City, NV</td>
<td>Parabolic trough</td>
<td>Synthetic oil</td>
<td>0.5 h of heat storage; storage type: N.A.</td>
<td>Completed in 2007</td>
</tr>
<tr>
<td>5</td>
<td>Kimberlina solar thermal energy plant</td>
<td>Bakersfield, CA</td>
<td>Fresnel reflector</td>
<td>Water</td>
<td>No storage</td>
<td>Completed in 2008</td>
</tr>
<tr>
<td>5</td>
<td>Sierra sun tower</td>
<td>Lancaster, CA</td>
<td>Solar power tower</td>
<td>Water (218°C–440°C)</td>
<td>No storage</td>
<td>Completed in 2009</td>
</tr>
<tr>
<td>2</td>
<td>Keahole solar power</td>
<td>Keahole Point, HI</td>
<td>Parabolic trough</td>
<td>Xceltherm-600 (93°C–176°C)</td>
<td>2 h of heat storage; storage type: N.A.</td>
<td>Completed in 2009</td>
</tr>
<tr>
<td>1.5</td>
<td>Maricopa solar</td>
<td>Peoria, AZ</td>
<td>Parabolic dish stirling</td>
<td>N.A.</td>
<td>No storage</td>
<td>Completed in 2010</td>
</tr>
<tr>
<td>1</td>
<td>Saguaro solar power</td>
<td>Red Rock, AZ</td>
<td>Parabolic trough</td>
<td>Xceltherm-600 and n-pentane (120°C–300°C)</td>
<td>No storage, using natural gas as backup</td>
<td>Completed in 2006</td>
</tr>
</tbody>
</table>
2) Geology

The basic geologic requirement for the storage system is a confined permeable stratum at a depth where the hydrostatic pressure is enough to prevent boiling of the stored hot water. Just like geological CO₂ sequestration, sedimentary basins are very attractive candidates. Sedimentary basins are regions of long-term subsidence creating accommodation space for infilling by sediments (Allen and Allen, 2009). They are of tectonic origin and are gradually filled with deposition such as sandstones, mudrocks, limestone, etc., and compaction of sediments eroded from surrounding mountains. They range in size from as small as hundreds of meters to large parts of ocean basins.

Typically, sedimentary basins consist of alternating layers of coarse or porous and fine-textured sediments (Benson and Orr, 2008). Permeable and impermeable layers are interbedded with each other. Highly porous sediments such as sandstone, limestone and dolomite are highly permeable and thus have great storage potential for the injected hot water. Some fine sediments with very low permeability such as clay and shale are suitable for sealing the storage formation to prevent rapid vertical flow of the injected hot water.

There are a number of sedimentary basins in the United States. Coleman and Cahan (2012) listed 142 main basins in their USGS report *Preliminary catalog of the sedimentary basins of the United States*. Those basins provide plenty of potential capacities to develop HSTES systems over the country. Being a basin does not ensure the suitability for the development of the storage system. Further study of geological requirements and influential factors that may affect the system performance is provided
in Section 7. However, in practical operation, there are still far more factors than what are discussed in this thesis that need to be taken into consideration, according to the real site conditions.

4.1.4 Energy Conversion

The thermal energy stored in a HSTES system will finally be converted to electrical energy on demand via a heat engine. In thermodynamics, the Second Law of Thermodynamics limits the energy conversion from heat into work.

The most efficient work-producing engine theoretically possible is the reversible heat engine, or namely, the Carnot engine. The highest conversion efficiency possible is thus the Carnot efficiency. In the efficiency calculation of thermal power plants, either flash or binary, Carnot efficiency is usually taken as a rough estimation of the upper limit of efficiency (Mendrinos et al., 2012). In 1824, Nicolas Léonard Sadi Carnot introduced an ideal engine which operates on a cycle in a reversible way and described the principle (later known as Carnot’s theorem) that specifies the limits on the maximum efficiency that any heat engine can obtain, which thus solely depends on the difference between the hot and cold temperature reservoirs.

Carnot's theorem states (Sonntag et al., 1998):

1) All ideal engines operating between a pair of heat reservoirs (thermostats) of temperatures $T_{\text{sink}}$ and $T_{\text{source}}$, with $T_{\text{sink}} < T_{\text{source}}$, is equally efficient, regardless of the working substance employed or the operation details.

This efficiency (Carnot efficiency) can be expressed as:
\[ \eta_C = 1 - \frac{T_{\text{sink}}}{T_{\text{source}}} \]  \hspace{1cm} (1)

where \( T_{\text{source}} \) is the absolute temperature of the heat source, and \( T_{\text{sink}} \) is the absolute temperature of the heat sink.

2) Any other engine has an efficiency \( \eta \) such that there is always: \( \eta < \eta_{\text{Carnot}} \).

The efficiency of a reversible Carnot cycle is the upper bound of thermal efficiency for any heat engine working between the same temperature limits. However, such a "perfect" efficiency is only a theoretical value and is invariably far above the efficiency that real heat engines can achieve. Hence it has limited practical value and its limitation is inevitable when applied to any natural system.

A great amount of research has been done after Carnot's work in order to obtain a more accurate efficiency of heat engines in practice. Breakthrough was made by the present of the Finite Time Thermodynamics (FTT) theory. In 1975, Curzon and Ahlborn (1975) obtained the efficiency of the Carnot engine at maximum power output by considering the influence of finite rate heat transfer between the external heat reservoirs and the working fluid on the performance of a Carnot heat engine (Chen et al., 1999). The heat engine (known as Curzon-Ahlborn engine or CA engine) is modeled as endoreversible (internally reversible). All the irreversibilities are incorporated into the engine heat exchange with its reservoirs. The equation of this efficiency is expressed as:

\[ \eta_{\text{CA}} = 1 - \sqrt[\frac{T_{\text{sink}}}{T_{\text{source}}}} \]  \hspace{1cm} (2)
It is not difficult to see by comparing Eqs. (1) and (2) that the CA efficiency is always lower than the Carnot efficiency under the same condition. For example, assume a 25°C heat sink (cooling tower, etc.), engine efficiencies under different heat source temperatures calculated from two processes respectively, are plotted in Figure 16. As is shown in the figure, the CA efficiency is much lower than the Carnot efficiency with the same source and sink temperature. Curzon and Ahlborn (1975) emphasized that Eq. (2) could serve as quite an accurate guide to the best observed performance of real heat engines. In study of this theory, Bejan (1988) obtained practical thermal efficiency data from ten fossil fueled and nuclear power plants, plotted them with the theoretical values of CA efficiency and Carnot efficiency. Very good agreement between the CA results and experimental data was found. Further research work in non-equilibrium thermodynamics of practical systems confirmed the importance of the CA process for evaluating the bounds on the production or consumption of the mechanical energy from thermal energy in a finite time (Sieniutycz, 2009). Overall, research proved that the CA process provides a far more realistic bound than the Carnot process for the efficiency estimation of heat engines operating at maximum power. Hence in this paper, the CA process is adopted to estimate the efficiency of electrical power generation from thermal energy.

From Figure 16, it is not difficult to see the heat engine efficiency is a nonlinear function of the temperature. Both plots show the general trend that the higher the heat source temperature, the more efficient the energy conversion will be. At low source temperatures, the maximum efficiency is low yet increases rapidly with increasing
temperature, while as source temperature increases higher, the increasing trend flattens. It can also be obtained that when use hot water directly from the solar collectors at 250°C, the heat engine efficiency is about 25%.

![Heat engine efficiency under different temperatures](image)

Figure 16: Heat engine efficiency as a function of fluid temperature, showing the theoretic maximum engine conversion efficiency (Carnot efficiency and CA efficiency, respectively) under different working fluid temperatures (assume T_{sink} = 25°C)

### 4.2 Learning from ATES and Geological CO₂ Sequestration

There are some parallels between HSTES and geological CO₂ sequestration and aquifer thermal energy storage (ATES).

#### 4.2.1 CO₂ sequestration

For subsurface CO₂ storage and hot water storage, the principal requirements of the geological storage formation are the same: a large permeable storage stratum and an impermeable sealing formation to prevent the escape of stored fluid. Moreover, the densities and viscosities of the injected supercritical CO₂ and superheated water are all
significantly less than the original formation water. Both being buoyant and having a low viscosity, there is expected to be some similarity in the behavior of the two liquids in the reservoir. A great amount of research work on sites selection, reservoir characterization, reservoir maintenance, and operational practices developed for CO₂ storage could provide theoretical and practical references for storing hot water. One similar system is the CO₂ interim storage system (Farhat and Benson, 2013; Farhat et al., 2011). Overall, the HSTES systems could be developed in typical geological CO₂ storage formations such as depleted oil and gas reservoirs, deep saline aquifers (Holloway, 1997; Metz et al., 2005) and other sites such as abandoned low temperature geothermal fields which are unable to support geothermal production of electricity. However, it is noteworthy the storage of supercritical CO₂ is more complex than that of hot water since the first is a multiphase case and involves not only structural or hydrodynamic trapping (Bachu et al., 1994; Farhat and Benson, 2013; Gasda et al., 2013; Lu et al., 2013) but also capillary trapping (Matthew et al., 2004; Spiteri and Juanes, 2006), solubility trapping and mineral trapping (Bachu et al., 1994; Gunter et al., 1993; Kühn et al., 2013; Rani et al., 2013). The CO₂ storage systems also require deeper storage formations than most HSTES systems.

4.2.2 ATES

As illustrated in the previous section, ATES are also underground thermal energy storage systems which use groundwater for the heat transport into and out of an aquifer and as the main storage medium. However, ATES systems presented in literature or in operation so far can only work with low to medium temperature water (T<100 °C) while the proposed HSTES system is able to store high temperature water (T>200 °C).
Generally, ATES is used in space heating and cooling and has not been used in thermal energy storage for power generation. Another difference between the two storage systems is that most ATES systems are composed of a well doublet or a multi-well system. It has a warm zone and a separate cold zone under the ground: the hot water and the cold water do not mix. Despite these differences, the storage medium, storage mechanism and even the operation of these two underground thermal energy storage systems are almost the same. In that regard, the extensive research on ATES could offer quite a number of references to the development and assessment of the proposed HSTES system. This will be further discussed in Section 7.
5 BASE CASE MODEL

5.1 Overview

Assessing the technical feasibility and predicting the performance of the technology is the first and foremost task before developing the HSTES system in reality. Hence, there is the need to develop a base case model for the demonstration of the design and the evaluation of the system performance. Due to the complexity of the problem, and lack of experimental study and field data from similar cases, numerical modeling is used to simulate the behavior of the storage system in this study.

In this section, sections 5.2 and 5.3 will provide a detailed illustration on the development of a conceptual base case model of the HSTES system and the basic operating process used in this model. Section 5.4-5.5 will focus on the development of a numerical model based on the conceptual model using the TOUGH2 multiphase flow simulator (Pruess et al., 1999) and the quantitative analysis based on the numerical simulation results.

With the conceptual model and the simulation tools, we will be able to conduct an assessment of the system. In this study, the technology assessment will be composed of three key components:

1) Computing the recovery rate of the injected thermal energy to evaluate the energy efficiency of the storage system;

2) Assessing the pressure reaction during injection and production;
3) Simulating the spatial and temporal distributions of the thermal plume; analyzing the evolution of injected hot water in the aquifer, explaining the observed phenomenon and further predicting the long term performance of the system;

5.2 Conceptual Model

5.2.1 Geographical Setting

In this section, a base case model will be constructed to assess the performance of the proposed HSTES system.

As described in Section 4, HSTES systems would be developed at locations with both abundant solar resource and deep (h>400 m in this case) confined aquifers. In the base case model, we consider applying it in California, where 11 out of 18 announced solar thermal power plants in the United States are located. California has five major aquifer systems, four of which consist primarily of basin-fill deposits occupying tectonic depressions (Planert and Williams, 1995): the Basin and Range basins, the Central Valley, the Coastal Basins, and the northern California basin-fill aquifers. The *Ground Water Atlas of the United States* (Harris and Baker, 2012) has provided detailed illustration of these aquifers.

1) Central Valley

Central Valley comprises a huge aquifer filled with a large amount of sediments. The overall thickness of the filling sediments ranges from approximately 32,000 feet in the Tulare Basin to about 50,000 feet in the Sacramento Valley (Planert and Williams, 1995). The single large aquifer there (Central Valley Aquifer) is primarily sand and gravel with significant amounts of silt and clay eroded from mountains at the
boundaries of the valley. Depending on the location, deposits of such fine-grained materials-mostly clay and silt-make up as much as about 50% of the whole thickness of the valley-fill sediments. These fine materials form a large number of lenses and some part of the aquifer beds with minimal permeability.

2) Basin and Range basins

The Basin and Range basins comprise an assemblage of multiple sedimentary basin systems. The set of basins comprise a large portion of Nevada and the southern California desert. In this large region, aquifers are not regional or continuous because of the complex faulting. There are three principal aquifer types collectively referred to as the "Basin and Range aquifers". They are volcanic-rock aquifers which are primarily tuff, rhyolite, or basalt; carbonate-rock aquifers which are primarily limestones and dolomites; and basin-fill aquifers which are primarily unconsolidated sand and gravel (Planert and Williams, 1995). The main water-yielding materials in this area are unconsolidated alluvial-fan deposits. From the margins towards the centers, ground water generally turns from unconfined to confined condition as the unconsolidated deposits become finer grained. There are also other rock types within this physiographic province of low permeability and act as boundaries and insulating layers.

3) Coastal Basins

The Coastal Basins are a sequence of basins in the coastal areas. They very similar structures. All of them are filled with marine and alluvial sediments. In this region, two or more vertically sequential aquifers can be present in a basin, separated by confining units but hydraulically connected.
The basins are partly filled with unconsolidated and semi-consolidated marine sediments from the encroachment of the sea and with unconsolidated continental deposits consist of weathered igneous and sedimentary rock material transported there by mountain streams (Planert and Williams, 1995). Almost all continental deposits contain sand and gravel. The overall marine and continental deposits are tens of thousands of feet thick in some regions. Freshwater is primarily contained in aquifers consist of sand and gravel interbedded with confining units of fine-grained material, such as silt and clay.

4) Basin-fill aquifer

The valleys in the interior northern California are in structural troughs or depressions resulted from the folding and faulting of crystalline rocks (Planert and Williams, 1995). Permeable sediments eroded from the mountains, alluvial fan sediments and lake deposits fill a large part of the depressions. Ground water in the valleys is contained mostly in those unconsolidated sediments. The thickness of the unconsolidated deposits in the valleys ranges from about 300 to 1,700 feet (Planert and Williams, 1995). There is also ground water stored in fractures and joints of volcanic rocks. The appearance of confining layers depends upon locations.

From the geological perspective, all four regions in California described above would possibly have potential suitable sites with highly permeable storage aquifer of large storage capacity and also confined by thick consolidated impermeable layers. From the solar resource aspect, California, especially northern California, is one of the regions with the most abundant solar resource. The average daily solar irradiation in northern California is 7~8 kWh/(m²·day). Meanwhile, most solar thermal power plants in the US
are built within California (Tian and Zhao, 2013). All these conditions are very favorable for the construction of HSTES systems in California.

5.2.2 Conceptual Model

The conceptual model constructed is composed of a sandwich-like storage formation and a groundwater well. The piezometric surface of the storage formation is initially at the ground surface. The reservoir is a 50-meter-thick confined aquifer located at a depth of 1000 m below the surface. The aquifer is assumed homogeneous with a horizontal permeability \( (k_h) \) of \( 1.0 \times 10^{-12} \text{ m}^2 \) and a vertical permeability \( (k_v) \) of \( 1.0 \times 10^{-13} \text{ m}^2 \) (within the range of sandstone, limestone and dolomite). The upper and lower confining layers are also assumed homogeneous with much lower permeability \( (k_h=1.0 \times 10^{-19} \text{ m}^2, k_v=1.0 \times 10^{-20} \text{ m}^2, \text{within the range of shale and clay}) \). Since the confining layers are thick and impermeable, there is no fluid flow between the sandwich-like storage formation and the other geological formations above or below, however there is still heat transfer by thermal conduction. The well casing is also impermeable such that there is no mass transfer and limited heat transfer between the wellbore and the surrounding formations by conduction. The thermal properties of different strata are simplified to be the same while the hydraulic properties are different. Overall, the modeled system is composed of three layers in total: a 1000 m impermeable cap rock, a 50 m permeable storage aquifer and a 50 m lower confining layer. All three layers are homogeneous and assumed infinite horizontal areas.

Another important element of the proposed HSTES system is a groundwater well for hot water injection and recovery. In the base case model, the well is 1025 m in length,
6 inch (~0.15 m) in radius. It has an impermeable casing with the bottom 25 m screened. The well is installed into the ground with its bottom placed at a depth of 1,025 m (middle of the storage aquifer) and the top of the well leveled with the land surface and connected to the surface facility. The well screen is open to only the upper half of the storage formation to enhance thermal recovery from the thermal plume characterized by gravity override. In the storage system, injected hot water has a temperature much higher than that of the reservoir water. The wellbore water is ~250 °C while the residual water in the formation is only ~50 °C. As is shown in Figure 17, water density is a non-linear function of temperature. The density decreases with the increase in temperature. Accordingly, the hot injected water is much lighter than the cold formation residual water, results in a strong buoyancy flow. In the porous media around the wellbore, warmer water flows upward driven by buoyancy, and migrates laterally beneath the impermeable cap rock. Thus, warmer water accumulates at the top while cooler water flows downward and accumulates at the bottom of the formation. This results in a non-uniform temperature distribution. Hence, the well is screened only down to the middle of the storage formation in order to reduce the amount of colder water coming in from the lower part during the recovery period.

A schematic illustration of the conceptual model is provided in Figure 18.
Figure 17: Density of saturated liquid water is a function of temperature

Figure 18: Schematic base case conceptual model
5.3 Operating Procedure

A complete working cycle consists of a maximum of three processes: an injection process (denoted by “I”), a storage process without any operation (denoted by “S”) and a production process (denoted by “P”). Sometimes, there is no storage process as the situation dictates.

One main purpose of developing the HSTES system is to solve the time mismatch between the solar energy supply and the actual electricity demand. In the base case model, we consider a simple scenario of shifting surplus solar thermal energy (stored in hot water) produced at times of low-demand to high-demand.

In this base case model, we assume a facility base runs on a step function electricity demand as is shown in Figure 19. It is powered by a small solar thermal field with an inlet working fluid (water) temperature of 25 °C and an outlet fluid temperature of 250 °C. To match the demand and supply, a sequence of periodic two-month injection-production (I-P) working cycles is run on an HSTES system: during a low-demand month, the surplus hot water generated from the solar field is injected into the storage formation continuously, at a rate of 10 kg/s (12.5L/s). When the following high-demand month comes, hot water is recovered from storage at the same rate. Here we simplify the simulation by use a constant injection rate over a month. As a matter of fact, solar irradiation changes with time such that the amount of hot water generated from the solar field varies from hour to hour as is shown in Figure 20. The peak output occurs around the noon while there is zero output during night. Hence the flow from the field is not constant or continuous. So actually, we are using a flow rate that is the result of the
total amount of hot water injected into the ground within an injection month by the total time (30 days). In this process, the total mass and energy are conserved. Meanwhile, it allows us to run a continuous injection simulation throughout the whole month.

Figure 19: Solar thermal power generation and energy demand of the facility base in the base case scenario

Figure 20: Typical power generation from a solar field within a day
In this work, the thermal energy density of liquid water at 273.15 K (0°C) where its standard enthalpy of formation equals to zero is taken as the reference point of zero. Thus thermal energy density of liquid water at a temperature of 250°C is 1085.3 kJ/kg. In the base case, hot water at a temperature of 250°C is injected through the well at a rate of 10 kg/s during each injection month. The total thermal energy injected for storage is 7,812 MWh in each cycle. The corresponding thermal power is up to 10.85 MW. Use a daily solar insolation (averaged over the year) of 7 kWh/(m²·day) and a typical solar collector efficiency of 40% (Jedensjö, 2005; Kalogirou, 2004; Müller-Steinhagen and Trieb, 2004) and assume an inlet water (to the solar field) temperature of 25 °C, to heat that amount of water to 250 °C requires a total solar collector surface of 84,000 m² (~21 acre). If use the commercial Compact Linear Fresnel Reflectors (CLFR) field provided by Areva Solar with an annual heat generation efficiency of 2050 MWh/(acre·yr), it requires a field area of 41 acre.

In the base case model, a two-month preheating process is also included to heat up the storing environment and minimize the heat loss due to convection and conduction between injected hot water and the surrounding. During this process, hot water with the same temperature is injected at the same rate of 10 kg/s into the storage formation to create a large hot zone. A total thermal energy of 14,112 MWh is consumed throughout this preheating process. Figure 21 illustrates the complete operation procedure of the base case model.
5.4 Numerical Model Set-up

Based on the conceptual model, a numerical model is set up using the TOUGH2-EOS1 multiphase flow simulator (Pruess et al., 1999) with the PetraSim graphic user interface (Alcott et al., 2006; Yamamoto, 2008) for further quantitative study on the base case. Equation of State 1 module (EOS1: Water, non-isothermal) (Pruess et al., 1999) is a basic module for geothermal applications and can deal with water, water with tracer and heat. It also allows phase change between aqueous and gas phase, with boiling and heat transfer. Like other members of the TOUGH/MULKOM family of codes, TOUGH2 uses the “integral finite difference” (IFDM) method to calculate the numerical solutions of certain problems (Pruess et al., 1999). Space discretization in IFDM is made directly from the integral form of the basic conservation equations, without converting them into partial differential equations (Edwards, 1972). Time is discretized as a first-order
backward finite difference, which is fully implicitly, together with the 100% upstream weighting of flux terms at interfaces. It offers the benefits of avoiding impractical time step limitations in flow problems involving phase appearance/disappearance and achieving unconditional stability (Peaceman, 1977). For systems of regular grid blocks referred to a global coordinate system, the IFDM is completely equivalent to conventional FDM.

In the setting of the numerical model, a radially symmetric grid is used to model the wellbore and surrounding formations (Figure 22). The radial cross-section of the model is 10,000 meters in radius and 1,100 meters in height (Table 5). The outmost radius is set to be sufficiently large to avoid possible errors caused by boundary effects. In the vertical direction, the model is composed of three parallel formations top-down as illustrated in the conceptual model. The corresponding material properties are listed in Table 6.
Within the model, grids are refined in and around the well and the storage aquifer to provide more accuracy. The top two layers are also refined to ensure more realistic pressure values and wellhead conditions (Table 7). A similar process is done to the radial discretization: The innermost column of cells represents the wellbore and is assigned a radius of 0.15 m. Then the grid spacing gradually increases outward from 1.85 m to 200 m along the radius. The outmost column of cells is assigned a radius of 20 m and is given a “fixed state” condition to further minimize the boundary effects. It means that cells at the outmost boundary will maintain the initial (T, P) conditions throughout the simulation.
Table 5: Base case model dimensions and general parameters

<table>
<thead>
<tr>
<th>Model Dimensions</th>
<th>Radial Dimension</th>
<th>Radius is set to be large enough to eliminate the numerical boundary effects. A fixed boundary condition applied on the outmost boundary.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Radial Dimension</td>
<td>R=10,000 m</td>
<td>Radius is set to be large enough to eliminate the numerical boundary effects. A fixed boundary condition applied on the outmost boundary.</td>
</tr>
<tr>
<td>Vertical Dimension</td>
<td>Z=1,100 m</td>
<td>The top of the model is set to be the ground surface and the base is 1,100 m below the surface. A 1,000m-thick upper impermeable layer and a 50m-thick lower impermeable layer are separated by a 50m-thick storage formation.</td>
</tr>
<tr>
<td>Well Dimension</td>
<td>R=0.15m, Z=1,025m</td>
<td>The base of the screen is 1,025m below the land surface while the wellhead is right at the ground surface.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Initial Conditions</th>
<th>Pressure</th>
<th>Atmosphere pressure + hydrostatics pressure An atmosphere pressure of 1.01\times10^5 Pa is assumed to be the surface pressure of the model. From hydrostatic equilibrium, a pressure gradient of 9.8\times10^3 Pa/m is used to represent the groundwater.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pressure</td>
<td>Atmosphere</td>
<td>Atmosphere pressure + hydrostatics pressure An atmosphere pressure of 1.01\times10^5 Pa is assumed to be the surface pressure of the model. From hydrostatic equilibrium, a pressure gradient of 9.8\times10^3 Pa/m is used to represent the groundwater.</td>
</tr>
<tr>
<td>Temperature</td>
<td>Geothermal</td>
<td>Geothermal gradient =30°C/km A geothermal gradient of 30°C/km (typical value in the North American(Blackwell et al., 1991)) is used. With a surface temperature of 25°C, the bottom temperature of the model is around 58°C.</td>
</tr>
<tr>
<td>Temperature</td>
<td>Geothermal</td>
<td>Geothermal gradient =30°C/km A geothermal gradient of 30°C/km (typical value in the North American(Blackwell et al., 1991)) is used. With a surface temperature of 25°C, the bottom temperature of the model is around 58°C.</td>
</tr>
</tbody>
</table>
**Table 6: Material properties for the base case numerical model**

<table>
<thead>
<tr>
<th>Entire Model</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Thermal Conductivity (W/m·°C)</td>
<td>2.51</td>
</tr>
<tr>
<td>Rock Grain Specific Heat (J/Kg·°C)</td>
<td>920</td>
</tr>
<tr>
<td>Rock Density (Kg/m³)</td>
<td>2600</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Impermeable Layer</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Horizontal Permeability (m²)</td>
<td>1.0×10⁻¹⁹</td>
</tr>
<tr>
<td>Vertical Permeability (m²)</td>
<td>1.0×10⁻²⁰</td>
</tr>
<tr>
<td>Porosity</td>
<td>0.004</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Storage Formation</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Horizontal Permeability (m²)</td>
<td>1.0×10⁻¹²</td>
</tr>
<tr>
<td>Vertical Permeability (m²)</td>
<td>1.0×10⁻¹³</td>
</tr>
<tr>
<td>Porosity</td>
<td>0.25</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Wellbore</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Permeability (m²)</td>
<td>1.0×10⁻⁷</td>
</tr>
<tr>
<td>Porosity</td>
<td>0.98</td>
</tr>
</tbody>
</table>

**Table 7: Vertical discretization of the base case numerical model**

<table>
<thead>
<tr>
<th>Number of Layers</th>
<th>Thickness (m)</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>10</td>
<td>Surface layers.</td>
</tr>
<tr>
<td>46</td>
<td>20</td>
<td></td>
</tr>
<tr>
<td>10</td>
<td>5.5</td>
<td>Refined near the storage formation (upper).</td>
</tr>
<tr>
<td>10</td>
<td>5</td>
<td>Storage formation.</td>
</tr>
<tr>
<td>8</td>
<td>6.25</td>
<td>Refined near the storage formation (lower).</td>
</tr>
</tbody>
</table>
The wellbore is modeled by assigning very high permeability ($1.0 \times 10^{-7} \text{ m}^2$) to the corresponding cells (leftmost column in the radial cross-section). The well starts from the land surface and reaches down to the middle of the storage formation (25 m below the upper confining cap rock) with the bottom 25-meter portion fully screened. Since the cap rock is highly impermeable, the model does not include another impermeable layer as the well casing.

For the entire model, a set of initial conditions are imposed. A geothermal gradient of 30°C/km is used which is a typical geothermal gradient of North America (Blackwell et al., 1991). A pressure gradient of $9.8 \times 10^3 \text{ Pa/m}$ is used to introduce the initial hydrostatic pressure. The model is then run for 1000 years to achieve the equilibrium pressure. The surface temperature is set to be 25°C. These global conditions will be the same for all following models.

5.5 Simulation and Analyses

For the sake of simplicity, one month is assumed to comprise 30 days in all the simulations in this thesis. To clarify the expression, we count months from the start of the real working cycles and denote the first month of the first working cycle the 1st month. The preheating two months are referred to as the 1st and 2nd preheating months.

5.5.1 Water Production Driving Force

As illustrated, the density of liquid water is a function of temperature. Reservoir water with a temperature around 50°C has a density of 988 kg/m$^3$, while the density of the injected water (250°C) is only 799 kg/m$^3$. The density difference of 189 kg/m$^3$, results in a pressure difference up to $1.85 \times 10^6 \text{ Pa}$ (~18 atm) between the wellbore fluid
and the reservoir water at a depth of 1000m. It is possible for the hot water to flow up spontaneously along the wellbore under its own pressure gradient without using down-hole pumps.

In order to study the possibility of hot water flowing up the surface without artificial lifting, the fluid production ability from the well is studied using a well deliverability model with different productivity indices (PI). Study on the well deliverability models could be found at Coats (1977); Durlofsky (2000); Kiryukhin and Miroshnik (2012) and Porras et al. (2007). The concept of productivity index was introduced based on the theory that production wells operate on deliverability against a prescribed flowing well pressure \( P_{wb} \) with a productivity index (PI) (Muskat and Wyckoff, 1946). More specifically, in a bounded reservoir depleted by a well, the ratio of the flow rate to the pressure drawdown (the pressure drop between reservoir and wellbore) will stabilize to a constant value such that the flow rate can be calculated from:

\[
\dot{q} = PI(P_{wb} - P_a)
\]  

where \( \dot{q} \) denotes the rate of fluid flow from the well, \( P_{wb} \) is the bottom-hole pressure, and \( P_a \) represents the average pressure of the fluid in the reservoir.

The TOUGH2 codes provide a “Well on Delivery” (DELV) package to simulate such well deliverability model (Pruess et al., 1999). In TOUGH2, the mass production rate of phase \( \beta \) from a grid block with phase pressure \( P_\beta > P_{wb} \) is calculated from:

\[
\dot{m}_\beta = \frac{k_{\beta \beta}}{\mu_\beta} \rho_\beta \cdot PI \cdot (P_\beta - P_{wb})
\]
Here, $q_\beta$ denotes the flow rate from the well, $k_{r\beta}$ is the relative permeability of phase $\beta$, $\mu_\beta$ is the viscosity of phase $\beta$, $\rho_\beta$ is the density of phase $\beta$, $P_{wh}$ denotes the bottom-hole pressure, and $P_\beta$ represents the average pressure of phase $\beta$ in the reservoir.

In the TOUGH2 codes, the DELV condition is usually applied to the wellbore when the well is a single unite.

In our model, the wellbore is modeled as a column of grids as is shown in Figure 23. Known from hydrodynamics, flow rate between the adjacent grids is a linear function of the pressure difference between the two (upper and lower) grids. At the wellhead, if simplify the resistance effect from the surface facility (e.g., piping loss) to an overall resistance term, then the flow rate out of the well ($q_w$) could be expressed as:

$$q_w = k \cdot (P_{wh} - P_{out})$$  \hspace{1cm} (5)

Where $k$ is a resistance coefficient, representing the above ground resistance including viscous resistance loss. The higher the resistance, the lower the $k$ value would be. $P_{wh}$ is the wellhead pressure and $P_{out}$ denotes the outlet environment pressure at the surface.

With Eqs.(3) and (5) being of the same form, flow out of the top of the well could be modeled by assigning a specified “well” at the top of the wellbore (Figure 23) in the base model, against a prescribed outlet pressure ($P_{out}$) with a prescribed resistance at the ground surface. Different surface loss can be modeled by adjusting the PI value in the model.
In the simulation, a PI value of $5 \times 10^{-12}$ m$^2$ is used, which is similar to values used in modeling geothermal well flows (Alcott et al., 2012; Battistelli et al., 1997; Bhat et al., 2005). The model is then run for two months: one month injection at a rate of 10 kg/s followed by another month of production with the DELV condition assigned to the wellhead grid and an outlet pressure ($P_{out}$) of $1.01 \times 10^5$ Pa (1 atm). According to the simulation (Figure 24 and Figure 25), recovery flow could happen spontaneously without artificial lifting. Hot water flows out from the wellhead at a decreasing rate (from ~18 kg/s at the very beginning to ~6 kg/s at the end of the production month) with the decreasing pressure difference within the system. It indicates that it is applicable for the HSTES system to produce hot water without complex lifting facilities.
With a certain pipe resistance, the recovery flow rate could be adjusted by adjusting the outlet pressure. Simulations are conducted to study the recovery flow rates under different outlet pressures in two cases with different surface resistance. As is shown in Figures 24 and 25, recovery rates increase with the decrease in surface resistance or outlet pressure. In reality, recovery of the stored hot water is mostly operated with constant production rates. Facilities will be installed at the ground surface to adjust the resistance force and outlet pressure to keep a stable outflow rate with assistant flow meters.

![Recovery flow rate under different outlet pressure](image)

**Figure 24: Recovery flow rate under different outlet pressures with PI=2×10^{-12} m^3**
5.5.2 Simulation and Results

5.5.3.1 Subsurface Storage

1) Qualitative Analysis

Within a working cycle, 250°C water is injected into the storage formation at a constant flow rate of 10 kg/s for a month (30 days). Then the injection stops and the production starts. Hot water is recovered from storage at the same flow rate of 10 kg/s. An equal injection and production rate is set to provide a net zero mass loss. This helps sustain the geological situation of the storage system and maintain the reservoir pressure.

Figure 25: Recovery flow rate under different outlet pressures with PI=5×10^{-12} m^3
An example of such cycles for the first year was illustrated in Figure 21 in the previous texts. In the figure, positive a flow rate refers to injection while negative means production.

Figure 26 shows the simulated spatial distribution and temporal evolution of the injected hot water in the reservoir. As expected, a heat plume characterized by gravity override forms around the well screen. The lighter hot water overrides the denser cold water and remains in the upper portion of the aquifer underneath the sealing cap rock. Also since the viscosity of hot water is lower than that of cold water, the flow velocity of hot water is larger than that of the cold groundwater. Hence, the portion of the heat plume that near the cap rock (which is hottest) migrates faster than other portions, creating a peak in the flow pattern under the cap rock. Also it can be viewed that the temperature of the plume is highest around the well screen, as depicted by red, and then gradually decreases away from the injection well, as depicted by yellow and blue.
Figure 26: Truncated radial cross-sections showing evolution of the hot zone around the well: Left column shows the temperature distribution after the injection period and right column after the recovery period within the same cycle. Pictures in the same column compare hot zone profiles at the same stage of different cycles.

In this study, the heat-concentrated region (red zone in the cross-sectional profile) is denoted as “heat core” and the surrounding medium temperature region (yellow to blue zone) is denoted as “heat fringe”. Comparing the heat plume profiles throughout the 10 years’ operation (Figure 26), within the same working cycle, the heat core is always refilled during the injection period and depleted in the production period. The volume and
shape of the heat core at the same stage of different cycles do not change much from cycle to cycle (except for the first few cycles as a result of preheating). The depletion does not affect the heat fringe much and there is no obvious change in the overall plume shape within a cycle. The heat fringe gradually expands with time due to thermal conduction, resulting in an overall expansion of the heat plume. This gradual heat loss prevents the working fluid from having direct contact with the cold formation during a cycle. It also buffers changes within the heat core or the surrounding formation from affecting each other, so it helps keep the stability of the storage environment.

Throughout the subsurface process, heat loss happens not only by convection within the reservoir, but also by heat conduction between the well and the surrounding formation. Figure 27 shows the change of formation temperature along the well from cycle to cycle at different radii from the wellbore. The formation around the wellbore is gradually heated due to heat conduction from the line source (thermal well).

The temperature distribution is relatively uniform along the wellbore except the portion near the storage formation. The heat loss from the wellbore is a nonnegligible factor when evaluating the efficiency of the storage system and thus will be studied later in the thesis.
Figure 27: Formation temperature distribution and evolution around the wellbore for the base case model. (Rescaled with a horizontal exaggeration factor of 25)

2) Quantitative Analysis

To quantify the effectiveness of energy recovery, we define several efficiencies to count for energy loss during different processes. The Thermal Storage Efficiency ($\eta_s$) is defined as the ratio of the total amount of thermal energy recovered from the well to the
total amount of thermal energy injected into the well over a certain period. It counts in
the heat loss from both the wellbore and the reservoir storage. Then for a single injection-
storage-production (I-S-P) process, namely, a working cycle, \( \eta_s \) can be calculated from:

\[
\eta_s = \frac{M_{prod}}{M_{inj}}
\]  

(6)

where \( M_{prod} \) is the total thermal energy produced from the well in a cycle, and
\( M_{inj} \) is the total thermal energy injected into the well in a cycle.

From the simulation output, \( M_{prod} \) and \( M_{inj} \) can be calculated from flow rates and
the corresponding enthalpies:

\[
M_{inj} = \int_{t_1}^{t_2} (\dot{q}_{inj} \cdot h_t)dt
\]  

(7)

where \( t_1 \) and \( t_2 \) are the starting and ending time of the injection period in a cycle
respectively, \( \dot{q}_{inj} \) is the injection mass flow rate which is 10 kg/s in the base case model,
and \( h_t \) represents the specific enthalpy of the injected fluid. Define the enthalpy of liquid
water equals to zero at the temperature of 0 °C as the reference condition, thus the \( h_t \) in
the base case mode (i.e., the enthalpy of liquid water at a temperature of 250°C) is
1.085\( \times 10^6 \) J/kg.

Similarly, for heat recovery, there is:

\[
M_{prod} = \int_{h_1}^{h_2} (\dot{q}_{prod} \cdot h_t)dt
\]  

(8)
To count in the preheating period, we define a *Cumulative Thermal Storage Efficiency* ($\eta_{CS}$) as the ratio of cumulative thermal energy produced up to a specific time over the cumulative thermal energy injected up to that time.

5.5.3.2 Surface Process

After storage, the fluid recovered from the well can be hot liquid, a mixture of liquid and steam vapor, or purely steam vapor, depending on the pressure. In the surface treatment stage, the produced hot fluid goes into a flash system if the temperature is moderate to high or a binary system if the temperature is relatively low. Then either the vaporized steam separated from the liquid (in a flash system) or another working fluid with lower boiling point vaporized by the hot water (in a binary system) is used to run a turbine. The steam turbine extracts thermal energy from the hot vapor and drive the electricity generator on a rotating output shaft.

Since a solar thermal plant operates on the same thermodynamic principals and goes through the same energy conversion process from thermal energy to electrical power, it does not matter where the hot water (thermal energy carrier) comes from. The hot water used to generate electricity can either be obtained directly from solar collectors, or recovered from a constructed geological reservoir. In either case, the same equipment can take the hot water, and convert it into electrical energy, using standard steam turbines or binary Rankine cycle generators.

In the HSTES system, there is always a temperature drop after storage. According to Carnot’s theorem, lower temperature results in lower thermal-to-electrical energy conversion efficiency, which results in further efficiency differences between the two
cases (before and after storage). Hence, energy conversion efficiency should be taken into consideration when evaluating the performance of the proposed storage system.

To compare efficiency of electrical power generation potential before and after the storage, we define a *Relative Electricity Generation Efficiency* ($\eta_{re}$) as the ratio of the maximum amount of electrical energy that can be produced theoretically by the hot water recovered after storage to which could be produced by the hot water directly from the solar collectors. It can be calculated from the *Thermal Storage Efficiency* ($\eta_s$) and the *Relative CA efficiency* ($\eta_{CA}$) using:

$$\eta_{re} = \eta_s \cdot \eta_{CA}$$  \hspace{1cm} (9)

$\eta_{CA}$ is a normalized efficiency which is the ratio of the two theoretical CA efficiencies using hot water before and after storage

$$\eta_{CA} = \left[1 - \frac{T_s}{(T_o)_{prod}}\right] \div \left[1 - \frac{T_s}{(T_o)_{inj}}\right]$$  \hspace{1cm} (10)

where $T_s$ is the heat sink temperature and $T_o$ is the temperature of the hot water entering the electricity generation system. Both are absolute temperatures in units of Kelvin.

Figure 28 shows a 10-year plot of three efficiencies ($\eta_s, \eta_{re}$ and $\eta_{CA}$) averaged over each cycle respectively in the base case model. On the whole, the thermal storage efficiency plot and the relative electricity generation efficiency plot change synchronously. They decrease at the beginning until the 6th cycle (after about one year operation), and then start going up continuously in the following cycles. However, the
increment between the efficiencies for adjacent two months gets smaller and smaller. All three efficiency plots level off with time. The averaged thermal energy storage efficiencies for each cycle is all above 80%. It is 87.2% for the first cycle and then quickly decreases to a lowest value of 80.4% at the end of the first year, followed by a smooth and continuous increase afterwards. The $\eta_s$ value finally reaches 82.7% by the end of the simulation period of 10 years (60 cycles). The relative electricity generation efficiency is lower than the thermal storage efficiency. The $\eta_{re}$ is high (80.6%) for the first cycle and it decreases to a low value of 69.7% after 1 year (6 cycles) and afterwards, gradually increases to 73.3% after 10 years operation. The increments drop below 0.1% after 2 years for thermal storage efficiency and after 5 years for relative electricity generation efficiency. The cumulative thermal storage efficiency plot experiences a constant increasing trend with a decreasing rate of change throughout the simulation. The $\eta_{cs}$ plot finally levels out with time. It will approach the thermal storage efficiency plot given enough time.
Figure 28: Averaged efficiencies for each cycle over 60 cycles (10 years) with a preheating time of 2 months

5.5.3 Wellbore Heat Loss

During storage, there is an inevitable portion of thermal energy lost into the surrounding formations via heat conduction. Considering that the operation well in the HSTES system is long (typically >500m), the heat lost into the surrounding through the wellbore might be significant.

In geothermal engineering, there is a great amount of research conducted on wellbore-fluid temperature distribution and wellbore heat loss analysis since the pioneering work of Ramey (1962). In Ramey’s work, he provided a fundamental analytical model to address the problem of a single-phase flow through a single conduit.
within a line-source well. Subsequently, Alves et al. (1992), Hasan and Kabir (1994), Sagar et al. (1991) and Hasan et al. (2003) further generalized these models by allowing two-phase flow, changes in well deviation, variable thermal properties, kinetic energy and Joule-Thompson effects, etc.

While great advances have occurred in analytical solutions towards wellbore-fluid temperature modeling, there is also significant development in numerical wellbore heat modeling. Early in the 1970s, Raymond (1969) offered a numerical solution for fluid temperature in the well. Later, a number of other fully-coupled numerical models were also presented to simulate more complex scenarios or to serve the general purpose of reservoir simulation, such as those of Arnold (1990), Stone et al. (1989), Kabir et al. (1996), and Pourafshary et al. (2009).

In our study, heat loss through the wellbore is estimated by modeling another parallel scenario with hot water directly injected into the reservoir through the screen without the wellbore above the reservoir. The simulated thermal energy storage efficiency of this case is provided in Figure 29 together with the plot from the base case model with the complete well. From the plot, it can be noted that this is only a small portion of the injected thermal energy lost into the formation through the wellbore. When injecting hot water into the screen directly, ~87% of the injected heat could be recovered in a cycle after the stability of the system, while injecting from the wellhead, ~83% of the thermal energy input could be recovered. Energy lost from the wellbore is only ~4% in this case. This is because the temperature difference between the injected and the recovered water is small, hence the wellbore temperature is relatively stable.
without much cool-down during production. The thermal gradient between the fluid in the wellbore and the surrounding impermeable formation decreases with time as that zone heats up, which further slows down the heat transfer.

The relative electricity generation efficiency plots, to some degree, amplify the difference with/without the wellbore. While there is ~4% extra thermal energy loss from the wellbore, there is ~6% overall potential electrical energy loss (through the whole process from injecting hot water into the reservoir until the final electricity generation) due to the wellbore heat loss. The further efficiency drop is a result of the lower conversion rate from thermal energy to mechanical energy as a result of the temperature drop.

As is shown in the simulation results, the heat loss from the wellbore is about ~30% that from the reservoir. Meanwhile, since the wellbore does not affect the storage aquifer characterization and the study of the effect of geological and operational factors on the system performance, following simulations will get rid of the wellbore above the storage aquifer. Simulation time is greatly reduced accordingly. The model with a complete wellbore requires several days to a week to run the 10 years case while without wellbore, it only needs about a day to simulate. The focus will be on the reservoir and the operation. Correspondingly, this simplified base case model without the complete wellbore simulated above will be used as the new base case model in following studies to ensure a single-factor-variable comparison. Note that this simplification will cause a slight increase in the simulated efficiencies.
5.5.4 Comparing HSTES to Other Existing Energy Storage Methods

Currently, electrical energy can only be stored after the conversion into other forms of energy (Simbolotti and Kempener, 2012). Table 8 listed some key factors of electricity storage methods that are currently available. Conventional commercial storage methods such as pumped hydro power storage and compressed air energy storage. Electrical batteries can achieve high efficiency. However, they are expensive and have the problem of short life time when applied in long-term storage system. Other novel
energy storage methods include flywheels, supercapacitor and superconducting magnetic storage, etc., most of them are still in the pre-commercial stage. Furthermore, some of them have the problem of limited output capacity or being economically unattractive. There is still requirement for further R&D work before their full commercialization.

Table 8: Comparison of current electricity storage methods [Data source: Simbolotti and Kempener (2012)]

<table>
<thead>
<tr>
<th>Storage methods</th>
<th>Status</th>
<th>Typical power output, MWe</th>
<th>Typical storage capacity</th>
<th>Energy storage efficiency, %</th>
<th>Life time, yr (cycles)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pumped Hydro</td>
<td>commercial</td>
<td>250-1000</td>
<td>50-150 MWh</td>
<td>70-80</td>
<td>&gt;30</td>
</tr>
<tr>
<td>CAES</td>
<td>commercial</td>
<td>100-300</td>
<td>0-150 MWh</td>
<td>45-60</td>
<td>30</td>
</tr>
<tr>
<td>Fly Wheels</td>
<td>pre-commercial</td>
<td>0.01-10</td>
<td>N.A.</td>
<td>&gt;85</td>
<td>20</td>
</tr>
<tr>
<td>Supercapacitors</td>
<td>R&amp;D; pre-commercial</td>
<td>0.1-10</td>
<td>N.A.</td>
<td>90</td>
<td>5×10⁴ cycles</td>
</tr>
<tr>
<td>Li-ion battery</td>
<td>pre-commercial</td>
<td>0.1-5 (&lt;10)</td>
<td>250-500</td>
<td>90 DC</td>
<td>8-15</td>
</tr>
<tr>
<td>Lead battery</td>
<td>pre-commercial</td>
<td>3-20</td>
<td>N.A.</td>
<td>75/80 DC; 79/75 AC</td>
<td>4-8</td>
</tr>
<tr>
<td>NaS battery</td>
<td>pre-commercial</td>
<td>30-35</td>
<td>50-150 MWh</td>
<td>80/85 DC; 60/70 AC</td>
<td>15</td>
</tr>
<tr>
<td>VRB</td>
<td>pre-commercial</td>
<td>0.01-10</td>
<td>250-300 MWh</td>
<td>75/80 DC; 60/70 AC</td>
<td>5-15</td>
</tr>
<tr>
<td>SMES</td>
<td>R&amp;D; demo</td>
<td>0.1-10+</td>
<td>N.A.</td>
<td>&gt;90</td>
<td>&gt; 5×10¹⁰ cycles</td>
</tr>
<tr>
<td>TES</td>
<td>STES</td>
<td>25</td>
<td>10-50 kWh/t</td>
<td>50-90</td>
<td>10-30+ (depending on storage cycles, temperature and AC)</td>
</tr>
<tr>
<td></td>
<td>PCM</td>
<td>0.5</td>
<td>50-150 kWh/t</td>
<td>75-90</td>
<td>75-100</td>
</tr>
<tr>
<td></td>
<td>TCS</td>
<td>100</td>
<td>120-250 kWh/t</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

[1] Pumped hydro power storage method converts surplus electricity to gravitational potential energy by pumping water from a lower reservoir to an upper reservoir. The stored energy will be used to produce hydropower on demand.

[2] Compressed air energy storage (CAES) systems store energy by compressing air. The compressed air is stored in large, low-cost natural buffers (e.g. caverns) and then used in gas-fired turbines to generate electricity.

[3] Flywheels store electricity as mechanical energy and then convert mechanical energy back to electricity on demand.

[4] Supercapacitor, also named ultracapacitor, is the generic term for a family of electrochemical capacitors. It stores electricity as electrostatic energy and is often combined with batteries.
Electrical batteries and vanadium redox flow cells/batteries (VRB) store electricity as chemical energy. Novel battery concepts (e.g. NaS batteries) and vanadium redox flow cells have already been used in small-to-mid size renewable power systems.

Superconducting magnetic storage (SMES) uses superconducting technology to store electricity.

Thermal energy storage (TES) method stores potential electrical energy as thermal energy. It has already been demonstrated in concentrating solar power (CSP) plants where excess daily solar heat is stored and then used to generate electricity at sunset.

Sensible thermal energy storage (STES) is a type of TES, it stores heat as internal energy in the storage medium without phase change.

Phase change material (PCM) stores thermal energy as latent heat.

Thermo-chemical storage (TCS) uses chemical reactions to store and release thermal energy.

In the base case model, the thermal energy storage efficiency of the proposed HSTES system is estimated to be >73% in the long run. With possible optimization and more suitable geological storage formation, the energy efficiency could be further improved. Also since the system occupies little surface space, it has a wide range storage capacity from thousands of kWh to tens of thousands of MWh of electrical energy equivalent, wider than most storage methods in the table would have. As a type of thermal energy storage (TES) methods for electricity energy storage, HSTES demonstrates great performance, higher than average efficiency, and possibly longer life time than most other methods.
6 SYSTEM CHARACTERIZATION

6.1 System Performance under Different Injection Temperatures

A major feature that distinguishes the proposed HSTES system from other existing aquifer or ground source thermal storage systems is its ability for storing hot water at a temperature higher than the standard boiling point of water. Storing high temperature water has its advantage in the energy conversion process because the efficiency of a heat engine increases with an increasing source temperature. However, the relationship between the source temperature and the thermal storage efficiency of the proposed system is still unknown. In this section, the performance of the HSTES system is studied under different injection temperatures. We keep all the other settings in the base case model constant, change the temperature of injected water to 200 °C and 300 °C respectively and simulate two new cases. Results from simulation are presented in Figures 30 and 31 by means of three different efficiency plots.

Within the simulation range, an increase in the temperature of injected hot water results in a decrease in the storage efficiency of thermal energy (Figure 30). After about 5 years, \( \eta_s \) is 90% for the case with an injection temperature of 200 °C, 86% for the base case with an injection temperature of 250 °C and 80% for the last case with an injection temperature of 300 °C. On the other hand, the situation of heat engine efficiency is just the opposite (Figure 31): the CA efficiency is highest for the 300 °C case and is lowest for the 200 °C case, coincides with Carnot’s theorem. The relative electricity generation efficiency represents heat losses from both storing and energy conversion. Its relationship with the temperature of injected hot water depends on specific situation. In the cases
simulated, the relative electricity generation is still higher for models with lower injection temperatures. However, this is not a law.

It is not difficult to see from the figures that the HSTES system performs well under different temperatures. The system is able to work with a relatively wide range of temperature and performs well if the depth allows. However, the ability to store hot water at a higher temperature is at a cost of a drop in storage efficiency.

![Storage efficiency of hot water at different temperatures](image)

Figure 30: Thermal energy storage efficiency of cases with different injection temperature
Figure 31: Engine efficiency and relative electricity generation efficiency of the storage system under different injection temperatures

### 6.2 System Performance in Short-term and Long-term Storages

Offering scalable energy storage and satisfying flexible energy utilization rate are two main purposes of proposing the HSTES system. In this section, the model is tested with daily and seasonal storage cases to assess its performance in both short-term and long-term heat storage.

In a typical daily storage scenario, a HSTES system could be used to shift surplus thermal energy generated during peak hours (typically around noon) to high demand
hours at evening without solar insolation. In the simulation of such a short-term storage, a daily (24 hours) working cycle composes a four hours (10 am - 2 pm) injection process, a four hours (2 pm - 6 pm) storage period, another four hours (6 pm - 10 pm) recovery process, and finally twelve hours (6 pm - 10 am next day) without any processing. The four processes form a complete I-S-P-S working cycle. Both injection and production rates are 10 kg/s and the water temperature is 250 °C, the same as that in the base case. There is no preheating in this simulation.

The model has been simulated for 80 days, which is equivalent to 80 cycles. According to the simulated results (Figure 32), the daily I-S-P-S cyclic case yields a thermal energy storage efficiency of ~78% and a relative electricity generation efficiency of ~66% at the end of the simulation. Both two efficiency values have been stabilized. Since this model only simulates the major heat loss - the unrecovered thermal energy lost in the reservoir - the actually system efficiency will be a little lower if the wellbore heat loss is considered.
In the seasonal storage case, the HSTES system is used to alleviate the uneven seasonal distribution of solar energy. The surplus hot water generated in summer will be injected into the subsurface reservoir for storage. When winter comes and there is not enough solar energy to sustain the power generation to meet the demand, the stored hot water will be recovered to supplement the power generation. During fall and spring, the solar radiant power is about right to meet the demand. Hence, there is no heat injection or recovery in these two seasons. Accordingly, in the simulation of the seasonal storage, a complete cycle is composed of 3 months injection ($T_{inj}=250$ °C, $\dot{q}_{inj}=10$ kg/s) which corresponds to the summer, followed by 3 months storage (corresponding to the storage through autumn) followed by 3 months’ production at the same rate (corresponding to the heat recovery during winter) and finally, another 3 months without operation.

Figure 32: Energy efficiency of the daily I-S-P-S cyclic case
(corresponding to the spring). The model is run for 10 years with a preheating time of 2 months. Figure 33 shows the system performance as a function of time. The thermal energy storage efficiency plot shows a similar pattern as that of the base case model. It experiences a short period decrease followed by a continuous slow increase. Comparing with the base case, the energy efficiency is lower. With the recovery water temperature being lower, energy loss through the heat engine is higher. The end-time thermal energy storage efficiency is ~69% and the relative electricity generation efficiency is only 53% in this seasonal storage scenario, not including the wellbore heat losses. These two efficiencies are lower than those of in previous cases. For one reason, it is because that unlike the base case, there are two storage periods in each working cycle in this seasonal storage case during which more heat is lost into the reservoir and the confining formations. For another reason, cases with longer working cycles require a longer time to stabilize. The underground storage condition may still have not been stabilized after 10 years’ operation in this case. The energy efficiency will continue to increase with further simulation for at least several cycles.

However, a thermal energy storage efficiency of ~70% is still high for such a long-term storage. This storage requires almost no more maintenance and cost compared with the short-term storage while for most other storage methods, long-term storage usually requires a large amount of extra cost.

The cross-sectional profiles of the heat plume at different stages in a typical cycle (Cycle 5 in this case) are provided in Figure 34. We can clearly see the evolution of the plume within a year: during summer, the injected hot water refills the heat core and
slightly expands the heat plume; in the autumn, both injection and production are shut down and the hot water is sealed in the reservoir under the cap rock. Through the storage period, heat gradually conducts into the adjacent formations. However, because of the buffering zone, the diffusion process is slow. This results in a slight drop of the heat core temperature, which is shown on the profile as a shrinking of the red (core) region. However, the main heat plume does not change much after storage; the majority of the heat loss happens between the heat core and the heat plume. During the winter time, the stored thermal energy is recovered from the reservoir. The depletion of the heat core can be clearly viewed comparing the cross sectional reservoir profiles at the end of autumn and winter, respectively. In the spring that follows the winter, the reservoir is at rest. It can be seen from the profiles that the formation condition is quite stable throughout the last three months. After the depletion in winter, thermal gradient is much smaller in the reservoir. This further reduces heat loss from the hot zone.
Figure 33: Thermal energy storage efficiency plot as a function of time for the seasonal storage case with a ten-year time span.

Figure 34: Cross-sectional profiles showing the evolution of the heat plume within the 5th year.
7 STUDY OF INFLUENTIAL FACTORS

From the existing experience, the efficiency of geological storage systems depends on the geological and hydraulic properties of the reservoir and the operating process (Bridger and Allen, 2005; Lee, 2010; Paksoy, 2007). To further study the effects of different parameters on the storage performance, in this section, seven sets of scenarios will be simulated, each set with variable parameters. The study uses a single-variable method. Section 7.1 to 7.3 will focus on studying three operational factors [screen location, working cycle length (including the I/S/P proportion), and preheating period]. Section 7.4 to 7.7 will study geological factors with regard to reservoir characteristics (storage formation thickness, anisotropy, stratification and stratum shape and inclination). A summary of the model settings used in Section 7 is provided in Table 9. In all these scenarios, it is assumed that the aquifer is of constant thickness and porosity, and perfectly confined.
Table 9: Model settings for different cases in 7 scenarios

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Base case</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
<th>7</th>
</tr>
</thead>
<tbody>
<tr>
<td>Case</td>
<td>Base settings</td>
<td>1</td>
<td>2</td>
<td>3</td>
<td>4</td>
<td>5</td>
<td>6</td>
<td>7</td>
</tr>
<tr>
<td>Influential factor</td>
<td>Screen location</td>
<td>Cycle length &amp; I/S/P proportion</td>
<td>Preheating</td>
<td>Formation thickness</td>
<td>Permeability anisotropy</td>
<td>Formation shape</td>
<td>Stratification</td>
<td></td>
</tr>
<tr>
<td>$k_h^{[1]}$ (m$^2$)</td>
<td>$1 \times 10^{-12}$</td>
<td>$1 \times 10^{-12}$</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$k_v^{[2]}$ (m$^2$)</td>
<td>$1 \times 10^{-13}$</td>
<td>$1 \times 10^{-13}$</td>
<td>$1 \times 10^{-12}$</td>
<td>$1 \times 10^{-14}$</td>
<td>$1 \times 10^{-13}$</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$b^{[3]}$ (m)</td>
<td>50</td>
<td>50</td>
<td>25</td>
<td>100</td>
<td>50</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Impermeable lenses</td>
<td>None</td>
<td>None</td>
<td></td>
<td></td>
<td></td>
<td>1</td>
<td>2</td>
<td>3</td>
</tr>
<tr>
<td>Shape</td>
<td>Flat</td>
<td>Flat</td>
<td>Basin</td>
<td>Dome</td>
<td>Flat</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Screen</td>
<td>Half screened</td>
<td>Fully screened</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cycle length</td>
<td>2mon</td>
<td>2mon</td>
<td>2d</td>
<td>3mon</td>
<td>3d</td>
<td>3d</td>
<td>1:1</td>
<td>1:1:1</td>
</tr>
<tr>
<td>Preheating</td>
<td>2mon</td>
<td>2mon</td>
<td>2d</td>
<td>2mon</td>
<td>2d</td>
<td>None</td>
<td>2mon</td>
<td></td>
</tr>
</tbody>
</table>
7.1 Scenario 1: Effect of Screen Location

In previous sections, we have discussed the buoyant heat plume formed in the reservoir during operation and our intention not to install the well down to the bottom of the aquifer because of the gravity override effect of the plume. To verify if this can actually reduce the cold water intrusion into the well and thus enhance the efficiency of heat recovery, a fully screened model will be simulated in this section and compared with the half screened base case model. The effect of screen length and location will also be studied.

Figure 35 provides a graphic illustration of the half screened model (the base case) and the fully screened model (Case 1). The only difference is that in the base case model, the well screen only reaches the middle of the reservoir while in Case 1, the well screen reaches the bottom of the reservoir. All other settings and operations are the same as those in the base case model. Two months preheating and ten years cyclic I-P processes are simulated for both models.
The changes in thermal energy storage efficiency are plotted as a function of time in Figure 36 for these two cases. Results from simulation confirmed our assumption. By injecting and producing from the upper half of the reservoir, the storage system can recover 10% more thermal energy than operating throughout the whole aquifer thickness. Figure 37 provides the reservoirs’ cross-sectional profiles in the two models during the 60th working cycle (at the end of the 5th year). It is not difficult to see that there is more residual heat after production in the aquifer in Case 1.

In the fully screened model, hot water moves upward under the buoyancy force, so there is much less hot water in the lower part of the aquifer than in the upper part. During production, hot water in the lower portion is soon depleted. As a result, cold reservoir water starts to flow into the wellbore, which consequently lowers the storage efficiency.
Figure 36: Thermal energy storage efficiency plots for Scenario 1: comparing system performance between the half screened and the fully screened case.

Figure 37: Reservoir cross-sectional profiles at the end of the injection and production processes of the 60th cycle showing the difference in two cases.
7.2 Scenario 2: Effect of Cycle Length and I/S/P Proportion

Each working cycle in the base case model is two months in length which contains one month injection followed by another month production. The time proportion of the injection, storage and production processes (referred to as “I/S/P proportion” or “I:S:P”) of the base case model is 1:0:1. In this section, three new models are built, together with the base case model, to study the effect of both working cycle length and the I/S/P proportion within a cycle on the system performance. The settings of all four simulations are listed in Table 10. Models in the same group have the same I/S/P proportion. Besides, in simulation, each model is assigned with a preheating period twice the length of its own injection process within a single cycle.

Table 10: Operation settings for Cases 2, 3, 4 and the base case

<table>
<thead>
<tr>
<th>Group #</th>
<th>Base case</th>
<th>Case 2</th>
<th>Case 3</th>
<th>Case 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Working cycle length</td>
<td>2 months</td>
<td>2 days</td>
<td>3 months</td>
<td>3 days</td>
</tr>
<tr>
<td>I:S:P proportion</td>
<td>1:0:1</td>
<td>1:0:1</td>
<td>1:1:1</td>
<td>1:1:1</td>
</tr>
<tr>
<td>Preheating time</td>
<td>2 months</td>
<td>2 days</td>
<td>2 months</td>
<td>2 days</td>
</tr>
</tbody>
</table>

The thermal energy storage efficiencies for all four cases are plotted as a function of cycle numbers in Figure 38. Despite the large difference in cycle lengths (up to a factor of 30), models with the same I/S/P proportion value have similar system performance and yield very close energy efficiencies.

The thermal energy storage efficiency (\( \eta_s \)) plots of models in Group 1 (I:S:P=1:0:1) converge to 87% and in Group 2 (I:S:P=1:1:1) converge to 82%. The difference is no more than 1% between models in the same group.
These simulations indicate that the I/S/P proportion is more important than the exact time spans in influencing the efficiency of heat recovery. Cases with the same I/S/P proportion have almost the same thermal storage efficiency after the stabilization of system performance, despite the big difference in the exact cycle length or the time span of each individual process within a cycle.

1). Base Case

Two-month cyclic case (I:S:P=1:0:1)

2). Case 2

Two-day cyclic case (I:S:P=1:0:1)

3). Case 3

Three-month cyclic case (I:S:P=1:1:1)

4). Case 4

Three-day cyclic case (I:S:P=1:1:1)

Figure 38: Thermal energy storage efficiency for cases with different cycle lengths and I/S/P proportions
7.3 **Scenario 3: Effect of Preheating**

The preheating process is conducted to heat the reservoir before real working cycles start. From previous simulations, it is not difficult to see that the preheating process helps increase the thermal storage efficiency at least for the first few cycles. However, it decreases the cumulative thermal energy storage efficiency as a trade-off.

In this section, the effect, especially the long term effect of preheating on the system performance will be studied. The model in Case 5 has the same settings as the base case model except it does not have a preheating process. Figure 39 shows both the thermal energy storage efficiency and the cumulative thermal energy storage efficiency as a function of time for both Case 5 and the base case. Figure 40 provides a graphic comparison of the heat plumes in two cases. Without preheating, the $\eta_s$ is low at the very beginning. The first cycle $\eta_s$ is only 76.5% in Case 5 while it is 93.3% in the base case. However, the difference in $\eta_s$ between two cases gets smaller and smaller. The difference is only 2% after 1 year. About two and a half years later, the difference drops below 1%. Unlike the thermal energy storage efficiency, the cumulative storage efficiency ($\eta_{cs}$) of the base case model is much lower than that of Case 5 at the beginning of simulation, but it increases sharply. The $\eta_{cs}$ plots of two cases also converge quickly. According to these results, the effect of preheating on system performance does not last long.
Figure 39: Thermal energy storage efficiency plots and cumulative thermal energy storage efficiency plots comparing system performance with and without preheating.

Figure 40: Cross-sectional profiles showing the evolution of the heat plume in the reservoir in cases with and without preheating.
To conclude, the simulation indicates a tendency of convergence between cases with and without preheating. After a certain period of time (~2.5 years), there is not much difference in performance between two cases. In other words, the preheating process does not make a big difference in the long run.

### 7.4 Scenario 4: Effect of Storage Formation Thickness

In this section, two cases with different storage formation thicknesses are simulated. With all other geological and operational settings being the same, the aquifer thickness is 25 m in Case 6 and 100 m in Case 7. These two thicknesses are ½ and twice that of the base case model, respectively.

Throughout the 10 years operation, differences in system performance are presented among them (Figure 41): within the range we studied, the thermal energy storage efficiency of the system increases with the decrease in storage formation thickness. After 60 cycles, the $\eta_s$ is 90.0% in Case 6 (h=25 m), 86.7% in the base case (h=50 m), and 77.0% in Case 7 (h=100 m). Overall, the thicker the reservoir is, the lower the storage efficiency will be. This phenomenon is very similar to what obtained from studies of the storage and recovery of freshwater in deep saline aquifer: a smaller formation thickness leads to more favorable recoveries (Kumar and Kimbler, 1970).

Figure 42 provides a further look into the efficiency differences with regard to the reservoir thickness. With hot water injected into the upper half of the reservoir, the cold reservoir water around the well is displaced by hot water in Case 6 (h=25 m). The heat core develops and covers the full thickness of the reservoir in this case. However, in the
base case model, the heat core formed around the well has a vertical extension only about 2/3 the aquifer thickness. Finally in Case 7, only a limited region in the upper half aquifer has been heated by the injected hot water. As a consequence, the buoyancy effect on the plume is most significant in Case 7 (h=100 m).

One explanation of the observed phenomenon is that when the injected hot water comes out of the screen (especially from the bottom of the screen), it has a downward vertical velocity component initially. On the other hand, there is the upward buoyancy force which resists the downward flow and will possibly reverse the flow direction finally. In the 25 m-thick reservoir, the downward hot water flow is able to reach the bottom of the reservoir and displace the cold reservoir water around the well along the whole aquifer thickness. The vertical temperature gradient in the aquifer near the injection position is relatively small. In the 100 m-thick reservoir, the injected hot water only flows down half the aquifer thickness. The lower half of the reservoir is still cold. This results in a relatively large vertical temperature gradient and correspondingly, a large density gradient. Therefore, the buoyancy effect is much stronger in Case 6 than that in Case 7. This explains the fact that both the heat core and the overall heat plume are more compact around the well in Case 6 while in Case 7, the gravity override effect is stronger and the plume is sparser. It is much easier to recover thermal energy from a compact heat core, such that the storage system is more efficient in this scenario. This can be confirmed by comparing the residual heat in the reservoir after production in three cases from Figure 42.
Figure 41: Thermal energy storage efficiency as a function of time for cases with different storage formation thickness.

Figure 42: Cross-sectional profiles showing different temperature distribution and evolution in reservoirs of different thicknesses.
7.5 **Scenario 5: Effect of Permeability Anisotropy**

Geologic formations are generally anisotropic. The linear convective flow in an anisotropic porous medium was first studied by Castinel and Combarnous (1977) with anisotropy in permeability only. Later, Epherre (1977) proposed his study on cases with permeability and thermal conductivity both being anisotropic. Degan et al. (1995) expended the previous research work and provided both analytical and numerical solutions to convective heat transfer in a hydrodynamically and thermally anisotropic porous layer. Years later, Straughan and Walker (1996) studied the convection in an anisotropic porous medium with oblique principal axis. Further study under specific conditions is conducted by other researchers using advanced computer technologies. A common point of these researches is they all reveal that in a variety of scenarios, the horizontal-to-vertical (or the inverse) permeability ratio is an important parameter in determining the convective heat transfer in an anisotropic porous media.

In this section, we define a normalized number – the horizontal anisotropy factor \( \alpha_h \) as the ratio of horizontal permeability over vertical permeability – to express the hydrodynamic anisotropy of the aquifer medium. By changing the vertical permeability of the reservoir material in the base case, two new cases could be simulated with different \( \alpha_h \)'s. The horizontal anisotropy factors used in three models are 1.0 in Case 8, 10 in the base case and 100 in Case 9.

The thermal energy storage efficiency calculated from the simulation results is plotted as a function of time under different horizontal anisotropy factors in Figure 43. From the efficiency plots, Case 9 with the highest \( \alpha_h \) yields the highest efficiency. Its
final cycle storage efficiency is 90.2%, while Case 8 which has the lowest $\alpha_h$ only has a final cycle $\eta_s$ of 80.8%.

Simulations confirm that the anisotropy factor affects the flow pattern in porous medium and further affects the hot water distribution. A smaller horizontal anisotropy factor favors by vertical buoyant flow, which will decrease the heat recovery efficiency. This can be confirmed by the cross-sectional profiles in Figure 44: in reservoirs with higher horizontal anisotropy factors, heat plumes are more compact horizontally. The vertical redistribution of injected hot water from the buoyancy is much weaker in those cases.

![System performance with different horizontal anisotropy factors](image)

Figure 43: System thermal energy storage efficiency as a function of time under different horizontal anisotropy
7.6 Scenario 6: Effect of Storage Formation Shape

In previous sections, the storage strata are all flat layers. However, in reality, few rock strata are really flat. They can be tilted, folded (multi-folded) and faulted, resulting in complex geological structures. The structures of the reservoir and adjacent strata can significantly affect the trapping of the injected fluid, as well as the evolution or migration of the stored fluid. Natural underground reservoirs (e.g., oil and gas reservoirs) typically exist in predictable places - such as at the tops of anticlines, next to faults, beneath unconformities or in the updip pinchouts of sandstone beds.

A great amount of research work has been done on such topics. Bories and Combarnous (1973) proposed their experimental and theoretical study early in the 70’s,
on the natural convection in a sloping porous layer bounded by two parallel impermeable planes. Later, Vasseur et al. (1987) studied the natural convection in a thin, inclined, porous layer exposed to a constant heat flux and proposed an analytical prediction and a numerical solution with a good agreement. Bjørlykke et al. (1988) did the modeling of thermal convection in sedimentary basins using a porous three-layer model to simulate pore-water flow in a sedimentary basin with layers of different permeabilities. More recently, Mbaye et al. (1993) studied the heat transfer in an inclined porous layer bounded by a finite-thickness wall; Laouadi and Atif (2001) developed the model of convective heat transfer within multi-layer domes; Simms and Garven (2004) investigated the thermal convection in faulted extensional sedimentary basins.

In this work, three reservoir shapes, simple but typical in natural, will be modeled. They are flat layers (base case model), basins (Case 10) and underground domes (Case 11).
Figure 45: Schemes of three formation shapes: Vertical and radial cross-sections illustrate the construction of these formation shapes in the models.

Figure 45 provides a schematic illustration of three reservoir models. The basin and the dome are modeled as a cone and an inverted cone respectively, both with a radius of 98 m and an apex angle of 126°. All three cases are half screened. The total operation period is 10 years with two months preheating. The corresponding thermal energy storage efficiencies are plotted as a function of time in Figure 46. According to the results from modeling, storing hot water in the dome yields the highest thermal energy storage efficiency while storing in the basin yields the lowest. However, although the dome-shape reservoir and basin-shape reservoir in our models have the same apex angle, the efficiency gap between the base case and the dome case is larger than that between the
base case and the basin case. There is more than 5% difference between the first pair while there is only ~2% between the second pair. Storing hot water in a dome reservoir can improve the storage efficiency to ~92%. This is because the dome can limit the lateral migration of hot water away from the well and helps trap the heat around the well screen. On the contrary, in a basin reservoir, it is convenience for the injected hot water to migrate away from the well and lost into the sounding while it is very hard for the hot water to flow back to the well against buoyancy during production. Therefore, as is shown in Figure 47, the heat plume is the dome is the most compact among three while the plume in the basin reservoir is the sparsest.

![Effects of storage formation shape](image)

Figure 46: Thermal energy storage efficiency as a function of time for cases with different storage formation shape
7.7 Scenario 7: Effect of Stratification

In this scenario, it is assumed that the aquifer is perfectly stratified in the vicinity of the test wells.

7.7.1 Stratification in a Half Screened System

By adding one to three equally spaced 5-meter-thick impermeable layers to the aquifers in three cases separately, stratification is introduced into the models. The well screens in these cases also only reach the mid-point of the storage formation and they penetrate all impermeable layers along its length. Three models are also run with a
preheating process for two months and a sequence of two-month working cycles for ten years.

The thermal energy storage efficiencies from simulation are plotted as a function of time for three stratified cases as well as the base case in Figure 48. The heat plume evolution within the 30th cycle is taken as a representative evolution process and is presented in Figure 49 for all four cases.

The efficiency plots show an irregular relationship between the storage efficiency and the stratification. Looking into the heat plume evolution profiles, in Case 12 (with one impermeable layer) and Case 14 (with three impermeable layers), there is almost no gravity override effect presented. On the contrary, there is a “tail” of the heat plume trapped under lower impermeable layers in these two cases. After the production stage, these plume tails still could not be depleted. Correspondingly, the systems in Cases 12 and 13 are less efficient than that in the base case. However, Case 13 with two impermeable layers has higher efficiency than the base case. The heat plume and the heat core in this case are also the most compact among all four cases.
Figure 48: Thermal energy storage efficiency as a function of time for cases with different stratification under scenario of half screen

One explanation of the above phenomenon is due to the relative position of the well screen and the impermeable layers. Stratification divides the whole highly permeable aquifer into thin permeable layers (sub storing layers) interbedded with impermeable layers (lenses). In the half screened scenario, since the bottom of the well is not sealed and does not reach the bottom of the aquifer, water can flow out freely from the well bottom at a large rate. If there is a thin and confined (by the impermeable lenses in the stratified aquifer) permeable layer located around the well bottom, it might cause a large amount of hot water flow into this thin layer (shown as the long plume “tails” in Cases 11 and 13). In a thin permeable layer, it is difficult for heat in such a long tail to be
recovered during production. Hence, the storage efficiency is relatively low in such a case.

From these models, in a half-screened scenario, the relative position of stratification and the well screen is an important factor when considering the effect of stratification on the storage system performance.

Figure 49: Cross-sectional profiles showing different temperature distribution at the end of the injection and production period of the 30th cycle for cases with different stratification under the half-screened scenario. The little vertical purple lines indicate the well screen positions.
7.7.2  Stratification in a Fully Screened System

To further study the effect of reservoir stratification and exclude the influence from the well screen position, another set of fully screened cases (Cases 15~18) are studied. In these cases, the well screen has the same length as the aquifer thickness. The bottom of the well reaches the bottom of the aquifer.

![Thermal energy storage efficiency with different formation stratification (fully screened)](image)

Figure 50: Thermal energy storage efficiency as a function of time for cases with different stratification under the scenario of full screen

In such a fully screened scenario, there is a clear relationship between the system thermal energy storage efficiency and the stratification pattern of the reservoir: aquifer stratification will enhance the system performance. Within the simulation range, \( \eta_s \) increases with the increase in system stratification (Figure 50). Without any stratification (Case 15), the \( \eta_s \) is only 77.7% but with three 5-meter-thick impermeable layers, the \( \eta_s \)
increases to 87.7%. Figure 51 provides the cross-sectional profiles of the heat plume in different stages within the final working cycle. It can be clearly viewed that the impermeable layers within the storage formation act as the barriers for vertical flow. Stratification reduces the influence of buoyancy and helps improve thermal recovery.

Based on the results from Sections 7.7.1 and 7.7.2, it can be concluded that generally, appropriate stratification of the storage formation can reduce the effect of buoyancy on the thermal distribution and the heat plume evolution. However, the effect of stratification on storage efficiency depends on the position of the well screen in the stratified reservoir.
Figure 51: Cross-sectional profiles showing different temperature distribution at the end of the injection and production period of the 30th cycle for the fully screened cases with different stratification.
8 SUMMARY

This work proposes a new concept of storing high temperature water in a deep confined aquifer under high hydrostatic pressure as an alternative for conventional thermal or electrical energy storage methods.

Major results and conclusions from numerical simulations are summarized as following:

1) In a scenario of running cyclic injection-production alternating processes for 10 years with a cycle length of two months, an equal I/P rate of 10 kg/s, and a constant heat source temperature of 250°C, 83% of the injected thermal energy could be recovered and the relative electricity generation efficiency ($\eta_{re}$) can reach $\sim$73%. The reservoir heat loss is about 3.25 times the wellbore heat loss.

2) The thermal energy storage efficiency ($\eta_t$) of a HSTES system is inversely correlated with the injection temperature while the heat engine efficiency (CA efficiency) is positive correlated with the source temperature. The relationship between the temperature of hot water injected for storage and the relative electricity generation efficiency which reflects heat losses from both storage and the heat engine depends on the specific situation.

3) In a typical daily storage scenario with the purpose of shifting the surplus hot water produced at peak-production hours (10 am - 2 pm) to peak-demand hours without sunshine (6 pm -10 pm), the HSTES system has good performance with a thermal energy
storage efficiency ($\eta_s$) of 78% and a relative electricity generation efficiency ($\eta_{re}$) of 66%.

4) In a typical seasonal scenario with the purpose of shifting thermal energy from summer to winter with expand storage in fall, the $\eta_s$ of the storage system is ~69% and the $\eta_{re}$ reaches ~53% by the end of the simulation period of 10 years.

5) Injecting and producing hot water from the upper half of the reservoir can recover 10% more thermal energy than operating throughout the whole aquifer thickness for the case studied.

6) Cases simulated with the same I/S/P proportion have almost the same efficiency performance, despite the big difference in the exact time spans of injection, storage or production processes.

7) Simulations indicate that a few months of preheating does not make much of a contribution to system performance in the long run though it could increase the storage efficiency for the first few cycles.

8) A HSTES system with a thinner reservoir has better performance than that with a thicker reservoir. The simulated thermal energy storage efficiency is 90% for the 25-meter-thick aquifer case, 87% for the 50-meter-thick aquifer case and 77% for the 100-meter-thick aquifer case. The inverse correlation between reservoir thickness and efficiency is a result of the fact that the buoyancy effect on the heat distribution is weaker in a thinner confined aquifer than that in a thicker confined aquifer.

9) Permeability anisotropy is an important influential factor. With a fixed horizontal permeability, an increase in horizontal anisotropy factor will result in a
decrease in vertical flow, and thus, result in a weaker gravity override effect, thus enhancing the heat recovery.

10) The storage formation shape affects the heat distribution within the reservoir. In a dome-shape reservoir, the injected hot water forms a relatively compact heat plume around the well screen while in a basin-shape reservoir, hot water flows away from the well easily, which increases the difficulty in recovery.

11) The effect of aquifer stratification on the storage system is complex. Generally, impermeable lenses around the well screen reduce the local buoyancy effect, which is favored by heat recovery. However, it is also possible for these impermeable lenses to act as obstacles to hot water recovery by trapping the hot water underneath them when they happen to appear at some specific locations.
To conclude, according to this work, the proposed HSTES system has following advantages:

1) Extremely reliable, robust and safe

Due to the depth of the energy repository (at least 400 m below ground surface), the reliability and safety of the subsurface storage system is much higher than fossil fuel energy storage systems such as large diesel tanks or compressed natural gas bullets located on or near the surface.

2) Scalable energy storage capacity

The energy storage system can likely handle a wide range of energy storage amounts from a several thousand kWh to tens of thousands of MWh of electrical energy equivalent.

3) Application in isolated areas

The system could be used to support off-grid power generation in remote areas or severe environments such as deserts.

4) Potential to store extremely large amounts of energy for long period of time

Solar power plants are badly in need of high-capacity and cost-effective seasonal energy storage systems. Such systems can significantly increase the annual electricity production efficiency and ensure the full operation of solar power plants throughout the year without depending on fossil fuels. Generally, efficiency increases and the specific construction cost decreases with size. Sillman (1981) evaluated the performance of solar
energy systems with long-term storage capacity and announced that it increased linearly as the storage size increased up to the point of unconstrained operation.

Using the concepts and technologies proposed in this work, very large storage systems comprised of multiple wells, solar systems, and electrical generation systems, are possible. For example, a 100,000 MWh system (capable of sustaining 300,000 people for a month) only takes a core storage volume of about 100 m thick and 172 m in diameter. This is equivalent to the energy from about 9 million gallons of diesel. Also, since the storage is deep underground, it has little or no impact on the surface buildings and facilities, and the influence of landscape on location selection should not be a problem.

5) Flexible Energy Utilization Rate

This system can produce a large quantity of electricity quickly (over a span of several hours, days, or weeks), or a smaller amount of electricity over a longer period of time (over a span of several months) depending on the needs and anticipated grid outage.

6) Renewable Energy Generation

Thermal energy storage technology is a method of great potential for compensating for the inherent intermittency of renewable resources in power generation and solving the time mismatch between the renewable energy supply and electricity demand.

7) Large Cycle Life

The system is easily refilled once the heat is removed from the system.

8) High Electrical Energy Storage Efficiency

The ability to store high temperature water contributes to improving the engine efficiency during energy conversion. The energy storage efficiency of our proposed
system is competitive with that of high-performance electrical batteries, and may exceed the typical efficiencies of pumped water and cavern compressed air storage.


Jedensjö, T., 2005. A technical evaluation of the thermal solar collector systems at Bo01 in Malmö.


Matthew, F., Randal, G. and Ian, T., 2004. The function of gas-water relative permeability hysteresis in the sequestration of carbon dioxide in saline formations, SPE Asia Pacific Oil and Gas Conference and Exhibition.


Simbolotti, G. and Kempener, R., 2012. Electricity storage: technology brief. IEA-ETSAP and IRENA.


