eUtah
A Renewable Energy Roadmap

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A study by Arjun Makhijani, Ph.D
Commissioned by HEAL Utah

www.eUtahProject.org

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December 2010

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President, Institute for Energy and Environmental Research

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eUtah: A Renewable Energy Roadmap

Arjun Makhijani/prepared for HEAL Utah, Salt Lake City, Utah

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Acknowledgements

HEAL Utah is an organization with vision and guts married to practicality, and, most important for me, respect for the integrity of scientific and technical work. HEAL's current executive director, Vanessa Pierce, has embodied these leadership qualities in the course of this work. She seized the idea that we should show a positive alternative to nuclear energy and its creation of waste and plutonium with every megawatt-hour, and made it her own. When I suggested an Advisory Board that would lend experience and wisdom to help situate the study in the realities of the Utah electricity sector, she led the way in putting it together. So this study represents her vision as much as mine. I have been honored to work with her and the entire HEAL Utah staff during the long process of creating this study.

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I am especially grateful and thankful for the excellent work that HEAL Utah's Arthur Morris did in compiling the renewable energy data and entering it in an orderly way into spreadsheets and beginning the process of integrating the data into a model for Utah. He has been an insightful debate partner for ideas, and has checked a good bit of the work. It has been a special pleasure to work with him. His research and insights have been invaluable.

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Of course, when all is said and done, the responsibility for the findings and recommendations and for any errors and omissions that remain despite the best efforts of those who helped, including specifically the members of the Advisory Board, is mine alone. Specifically, the expertise of the Advisory Board

members has helped make this a much better report, but I alone am responsible for the contents, conclusions, and recommendations in this report.

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Arjun Makhijani
December 2010

I. Executive Summary

The energy sector has been in turmoil since the Organization of Petroleum Exporting Countries dramatically and suddenly increased oil prices in October 1973 and its Arab government members imposed an oil embargo on the West. New issues, most notably the prospect of a price or tax on carbon dioxide (CO_2) emissions, have emerged, though there is considerable uncertainty about the size of carbon-related cost. For many, nuclear power seemed to be an answer to the CO_2 emissions problem. But it is proving too risky for investors; the oft-proclaimed "nuclear renaissance" has not materialized at any meaningful level. As for federal policy, the prospect of sweeping legislation curbing carbon dioxide emissions has receded. The EPA proposes to limit them, but its continued authority to do so is under considerable political pressure. Some states are adopting caps nonetheless. Uncertainty reigns.

At the same time, the scale and pace of development in renewable electricity generation has been breathtaking. The United States has an installed capacity of wind energy approaching about 40,000 megawatts. Solar installations have increasingly become large-scale, with photovoltaics and concentrating solar power plants that are tens or hundreds of megawatts per installation, rather than finding solar installations of a few kilowatts on residential properties (which also continue). In the best wind areas such as the Dakotas and Wyoming, with capacity factors on the order of 40 percent, the costs of wind-generated electricity are comparable to new coal or natural gas combined cycle power plants even without subsidies and a price on carbon. Wind-generated electricity is now less expensive than nuclear[1] and remains lower than nuclear even when storage costs are added.[2]

Renewable energy resources are plentiful across the United States, and particularly in the region of the Western Interconnection grid, which includes Utah. State-level investment and policy has been and will remain critical to the development of the electricity sector. This study examines how options might be opened up in a perilous investment landscape that would make best use of Utah's resources and reduce the financial and environmental risks in an area that is vital to economic health.

We examine the Utah electricity sector by analyzing the supply and demand of PacifiCorp, which is the state's largest electricity provider, with about four-fifths of the total demand in the state. Our overall goal is to examine whether and how renewable energy sources, complemented by efficiency, can open up options for reducing risks in electricity sector investments while maintaining the present reliability of the system. Since one of the largest risks in electricity sector investments is related to the future of carbon prices, this study examines options to greatly reduce or nearly eliminate CO_2 emissions from the electricity sector. We examine reductions of 70 to 95 percent, compared to 2010, by the year 2050.

We developed five scenarios that are designed to yield insights into different approaches to reducing carbon emissions and managing investment risks. They are not designed as generation portfolios in a traditional Integrated Resource Plan (IRP), though they have some features of such plans, like a sensitivity analysis of different levels of fuel prices. Additionally, while this study analyzes the service territory of PacifiCorp in Utah, it does not purport to develop alternative investment approaches for the

[1] All cost estimates in this study are market-based estimates to the extent possible. Specifically, subsidies such as investment tax credits, production tax credits, federal loan guarantees, and interest-free financing by ratepayers are not included in any of the cost estimates.

[2] Compressed air energy storage costs, as estimated in this study work out to roughly $30 per MWh.

company. For instance, the scenario that is called "business-as-usual" is designed to represent a continuation of reliance on coal, which is at present Utah's primary electricity generation fuel. In contrast, PacifiCorp, while heavily reliant on coal at present in Utah, is investing mainly in natural gas-fired power plants and wind-generated electricity, a direction also recommended here, though with other elements added. The other four scenarios are also designed to yield insights into the consequences of different approaches to central station power plants for comparative purposes, rather than as prescriptions for future investment. Two scenarios analyze reductions of 70 to 80 percent in CO_2 emissions relative to 2010; while two analyze reductions of more than 90 percent. That way, the costs of different approaches as well as different levels of CO_2 emissions reductions can be compared. The result is an analysis that yields insights into carbon-related costs and risks as well as financial risks. This method allows us to compare how much strategies for reducing CO_2 emissions would cost. While this analysis is focused on Utah, at least some of it can be generalized to other parts of the country.

The five electricity supply scenarios developed in this study are:[3]

1. **Business-as-Usual (BAU)**: This is a reference scenario that assumes the continued dominance of coal in the supply system. Coal-fired power plants are generally replaced by coal-fired power plants. Existing plants are retired at 60 years.[4] No new efficiency or Demand-Side-Management (DSM) measures are assumed. A coal-to-coal scenario is useful as a reference because it allows us to compare the cost of the various low-carbon approaches to a continued high-carbon emissions electricity sector. In effect, this scenario assumes a zero carbon emissions cost. By allowing carbon emissions to rise in one scenario and be curbed in others, we can estimate what it will cost to reduce carbon emissions and infer a risk of a continued reliance on coal should there be a non-zero cost of CO_2 emissions in a coal-centered investment strategy.
2. **A low-CO_2 scenario with nuclear and coal with carbon capture and storage (Nuclear/CCS)**: This scenario provides an example of a conventional approach to CO_2 emissions reductions and assumes that the structure of the present electricity sector, which is dominated by thermal plants, will continue, but with carbon reductions as an added goal. Nuclear power and coal with carbon capture and storage are the main generation technologies in this scenario. Natural gas plays a supporting role, as it does at present in Utah. This scenario results in approximately 70 percent reductions in CO_2 emissions relative to emissions in 2010 and 80 percent relative to the emissions in 2050 in the BAU scenario. A medium level of efficiency improvements, typical of conventional utility planning, is assumed in this scenario.
3. **Renewables with natural gas (Renewables/Natural Gas)**: In this scenario, slightly greater reductions in CO_2 emissions than in the Nuclear/CCS scenario are achieved by using solar, wind, and geothermal generation, supplemented by a significant number of natural gas combined cycle power plants. A higher level of efficiency than the Nuclear/CCS scenario is used here. Since more than half the power is supplied by solar and wind, large-scale energy storage is needed. The reference technology for large-scale storage used in this study is compressed air energy storage (CAES).
4. **Renewables with natural gas and carbon capture and storage (Renewables/Natural Gas/CCS)**: This is the same as the Renewables/Natural Gas scenario, except that carbon capture and storage has been added to natural gas combined cycle power plants in order to achieve CO_2

[3] Attachment B specifies the assumptions and parameters used in these scenarios, including the sensitivity analysis.

[4] The retirement schedules used in this analysis are not PacifiCorp schedules, but constructed specifically for the scenarios in this study.

emissions reductions of 93 percent relative to 2010. It is comparable in CO_2 reductions to the eUtah scenario.

5. **eUtah scenario**: This scenario relies almost totally on renewable energy sources by 2050: wind, solar, and geothermal. The only non-renewable resource use is natural gas, which is used to reheat compressed air when it is withdrawn from the storage cavern. This scenario has CO_2 reductions of 97 percent relative to BAU in 2050 and about 95 percent relative to 2010.

At a time when Congress has not passed legislation mandating even modest reduction in U.S. greenhouse gas emissions, it is natural to raise the question of why this study includes scenarios that examine near complete elimination of CO_2 emissions from the Utah electricity sector.

There is broad, though not universal, agreement that reducing global greenhouse gas emissions by 80 percent by the year 2050 is needed in order to prevent widespread global economic, health, and environmental harm. A global reduction of greenhouse gas emissions by 85 percent, with allowances allocated on a per person basis, would mean a 96 percent reduction by 2050 in the United States. In this context, countries and even cities are developing plans that call for complete or near-total elimination of CO_2 emissions from the electricity sector, because it is anticipated that reducing emissions there will be lower cost than in some other sectors and because the electricity emissions represents are large fraction of greenhouse gas emissions (see Chapter II for more details).

This study examines only central station generation options, even for renewable energy sources. That is because it is very difficult at this stage to foresee the shape and cost of an intelligent electricity grid in which large numbers of distributed generation sources, storage types, and smart appliances would be managed as an integral part of grid operation. Designing an appropriate protocol for such a system not only requires detailed data for most major present electricity uses but also data from pilot programs that incorporate wide levels of demand dispatch, high efficiency buildings, and local generation and storage. Neither the data nor the system integration modeling capabilities exist today at a level of detail needed for a reliable technical analysis, much less a cost analysis. Yet the need for such a design tool emerges very clearly, since a centralized approach to large-scale use of renewable energy is shown to be financially inefficient due to a large amount of spilled, or wasted, energy. Spilled energy is solar and wind electricity that could have been utilized, but was not because there is a surplus of renewable electricity available relative to demand in periods when the storage capacity is also full. In effect, this surplus is wasted.

There is merit in criticizing the centralized-generation-only approach used to develop the scenarios here as a throwback to the era of punch-cards and mainframe computers in an age of distributed computing (as indeed the Chairman of the Federal Energy Regulatory Commission, Jon Wellinghof, has done[5]). But it turns out that in the context of scenarios designed to yield insights about directions, our approach yields important insights, including for next steps to a 21st century electricity systems.

The notion that solar and wind energy cannot be the mainstay of an electricity generation system because they are intermittent is incorrect. This study shows that they can be dispatched reliably when there is storage—and a commercial storage technology is available. We have maintained the usual reliability criterion—12 percent reserve margin over demand—in all scenarios for every hour of the year. Moreover, it turns out that choosing a direction of a Renewables/Natural Gas scenario for the coming

[5] Straub and Behr 2009

years is the lowest cost and risk among the low carbon scenarios. It is also compatible with a fully renewable distributed and intelligent electricity system in the longer term (beyond 2025).

Pioneering a renewable grid: dealing with the "relational system peak"

A principal insight that emerges from the analysis in this study is that the conventional notion of "peak load" needs to be abandoned in designing an electricity system with a high proportion of solar and wind energy. At present the system peak is determined entirely by consumers—it is the time of highest simultaneous load on the system. In a renewable energy system with storage, there may be plentiful energy available at such times, particularly in states like Utah with ample solar energy resources. The crunch time may be during periods of low solar energy supply—the winter[6]—when the wind energy supply stays low for long enough for stored energy to be depleted. We have called this phenomenon the "**relational system peak**." The electricity system of the future, if it is to have a large fraction of renewable energy, will need to optimize investments on the demand side as well as the generation side to minimize the cost of dealing with the relational peak, including investments to reduce it. Instead of the peak load that drives marginal investments in generation (and to a small extent in demand side management), dealing with the relational system peak will require comprehensive consideration of investments throughout the system (though not necessarily by utilities in all cases).

In reviewing the costs discussed below, it should be remembered that the electricity product being delivered is much different than the one delivered today even though the electrons coursing through the grid are the same. An analogy with cars is appropriate. They got people from one place to another in the 1960s, as do cars today. But present-day cars are much less polluting and much safer—to the point that we have many more of them with much less pollution and far fewer injuries. Similarly, in the electricity sector, the core product delivered—electrons speeding through the wires of the grid providing lighting and cooling and energy to drive industries—is the same, but the social, health, and safety consequences are far different. One part of the reason to pursue renewable-energy-centered approaches to carbon reductions is that they represent the lowest financial risk, another for pursuing them is that they deliver a far better product to society. People will literally breathe easier, water use will be far lower, by 15 to 20 billion gallons per year, and the risks related to CO_2 emissions will be nearly eliminated from the electricity sector. We have not covered the net jobs impact quantitatively in this study, but note here that there are ample renewable resources in the areas now dependent on coal mining to create renewable energy related jobs (also see Chapter VI).

A. Main Findings

- **A renewable electricity sector is technically feasible**: A transition to an essentially fully renewable and reliable electricity system in Utah is technically feasible with available and proven technologies. However, a centralized approach incurs significant added cost due to spilled energy. It may be possible to reduce it with the use of distributed technologies.
- **There are ample renewable resources in Utah**: Utah has sufficient solar, wind, and geothermal renewable energy resources to accomplish a transition to an essentially fully renewable

[6] The efficiency of solar generation is higher in the winter, but the availability of the resource is far smaller.

electricity system.[7] All the needed technologies are commercially available, though concentrating solar power and solar photovoltaics are at early stages of commercialization.

- **Several approaches to greatly reducing CO_2 emissions are possible**: There are several ways in which CO_2 emissions could be greatly reduced. Solar and wind energy with storage, and geothermal energy are among them, as are nuclear power and coal with carbon capture and storage (CCS). Natural gas combined cycle power plants with carbon capture and storage is also a possible method to reduce CO_2 emissions. The caveat with the CCS approaches is that carbon storage technology needs to be demonstrated on a scale that can support fossil fuel electricity generation.
- **An 80 percent reduction in CO_2 emissions relative to 2010 can be achieved at modest cost:**[8] The lowest cost carbon reduction scenario in this study is the Renewables/Natural Gas scenario, which achieves 80 percent CO_2 reductions by 2050. Specifically, it is more economical than the Nuclear/CCS case (70 percent CO_2 reduction relative to 2010). Residential electricity bills would increase by about $185 per person per year in 2050 relative to 2010, in the context of a per person gross domestic product increase from $37,000 at present to over $75,000 in 2050. The cost of spilled energy in the Renewables/Natural Gas scenario amounts to about $150 per person in 2050, with just under a third of that being reflected in the residential generation cost increase. Figure I-1 shows the residential generation costs per person in the five scenarios in 2050, with 2010 cost of $106 per person shown as a reference, as well as the increase in costs relative to 2010. Figure I-2 shows the residential generation cost per household in 2050. Per household generation costs for the residential sector would go up about three times (between 2.75 and 3.35 times) in the low CO_2 scenarios relative to 2010. The BAU scenario which has relatively low cost has a high carbon emissions cost risk (see below).

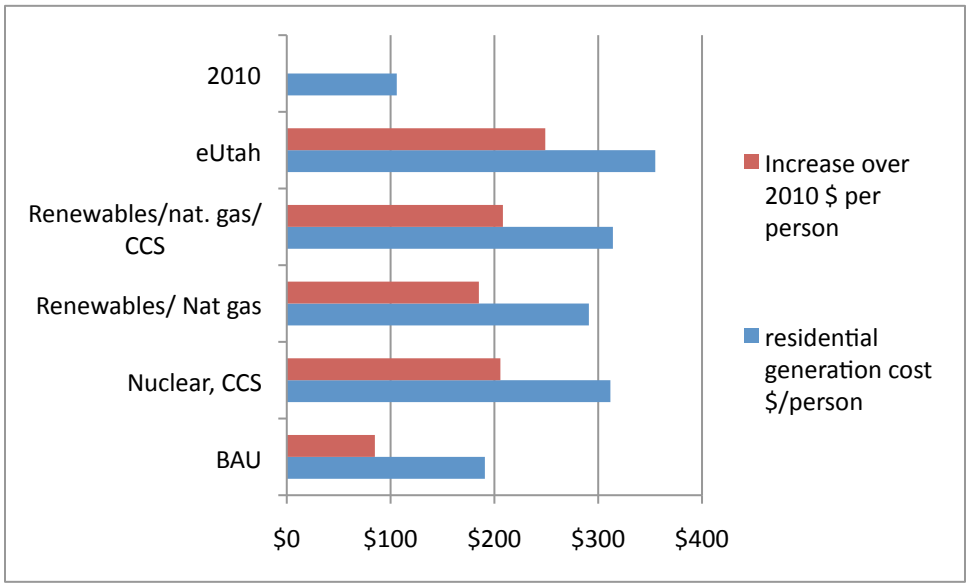

Figure I-1: Residential sector generation cost per person per year in 2050 and increase relative to 2010.

[7] The use of a small amount of natural gas for compressed air energy storage is assumed in the model developed in this report. This can be reduced by optimizing the renewable energy system in various ways. It can be eliminated should other storage methods, such as battery storage, become economical in the next ten to 15 years.

[8] All costs in this report are unsubsidized generation costs only (including storage costs, where applicable). Specifically, transmission and distribution costs are not included. Figures for the year 2010 are estimated.

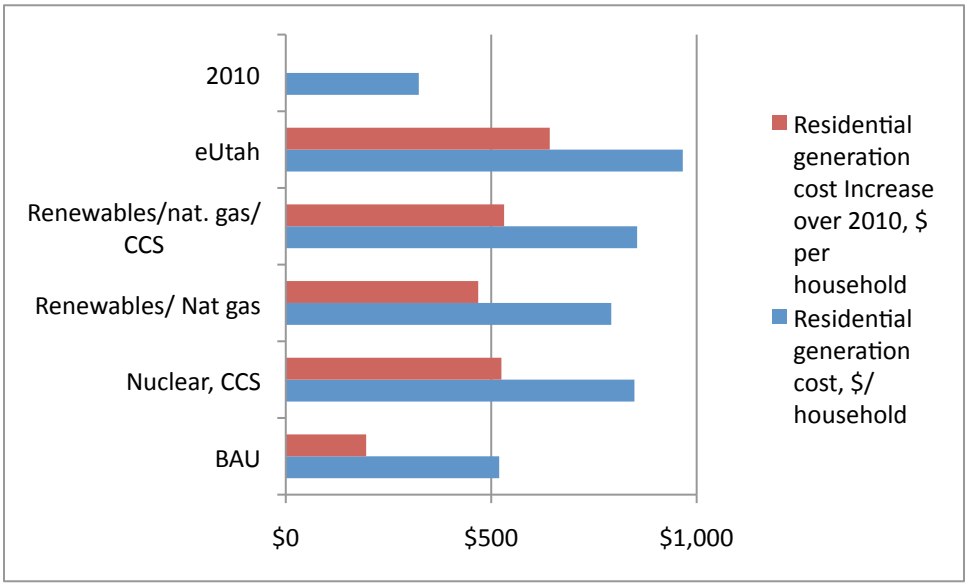

Figure I-2: Residential sector electricity generation costs per household per year, 2050 and cost increase relative to 2010.

- **The cost increase for reducing CO_2 emissions as a fraction of GDP is modest.** Figure I-3 shows the costs of generation costs in 2050 as a fraction of the GDP in that year. The costs are for Utah electricity generation for all consuming sectors. The 2010 value is shown for reference. The fraction of GDP devoted to generation is less than 2 percent of GDP in all cases. The BAU scenario cost declines as a fraction of GDP relative to 2010, but its carbon emission risk is high (see Figure I-5 and I-6 below).

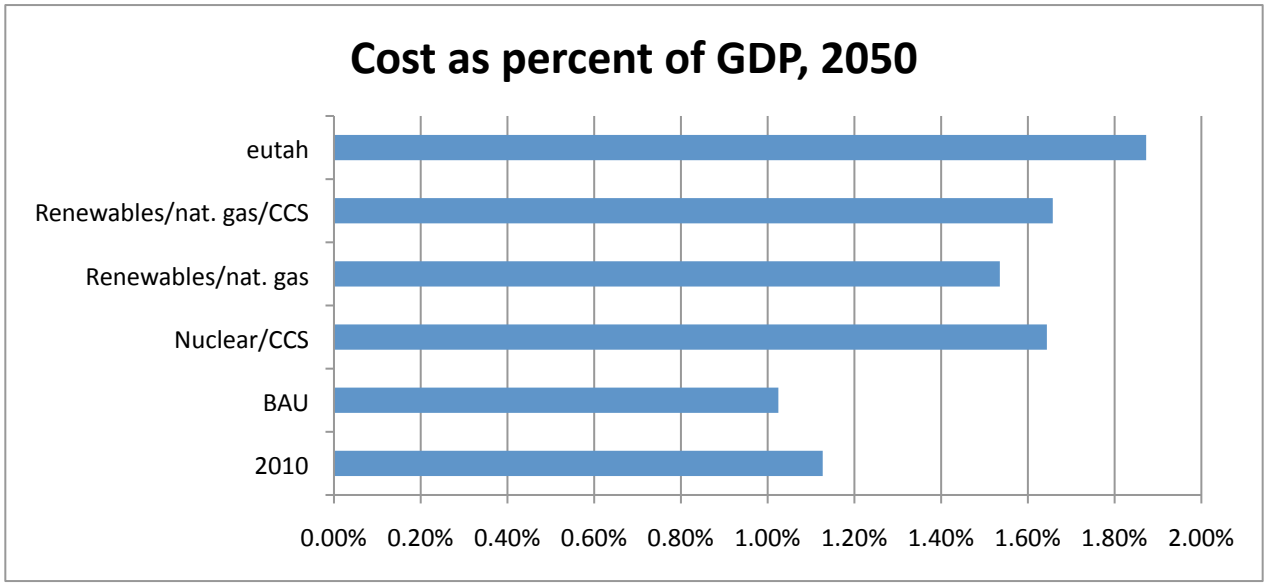

Figure I-3: Electricity generation costs in 2050 as a fraction of Utah GDP in that year, with the 2010 value shown for reference.

- **Spilled energy greatly increases the cost of reducing carbon emissions in the renewable scenarios:** There is a significant spilled energy cost embedded in all three renewable energy

scenarios. The highest spilled energy cost is in the eUtah scenario: about $1.4 billion in 2050.[9] The spilled energy cost in the Renewables/Natural Gas scenario is about $900 million in 2050. This provides an order of magnitude of the room for economic improvement of renewable energy supply compared to the centralized approach modeled in this study. Of course, one must take into account the investments needed to eliminate spilled energy.

- **Cost of carbon emissions reductions is estimated at $63 to $94 per metric ton, including spilled energy cost, with base case cost parameters:** There are two pairs of comparable scenarios in Figure I-4. The Nuclear/CCS is comparable to Renewables/Natural Gas (70 to 80 percent CO_2 reductions relative to 2010). The former achieves 70 percent reduction at a cost of about $81 per metric ton and the Renewables/Natural Gas scenario achieves 80 percent reduction at a cost of $63 per metric ton. The Renewables/Natural Gas/CCS and eUtah scenarios reduce CO_2 by over 90 percent. The former achieves reductions in CO_2 emissions at a cost of $71 per metric ton, which is less than the cost in the Nuclear/CCS scenario. In fact, the Renewables/Natural Gas/CCS scenario reduces CO_2 emissions by 93 percent for about the same total cost as the 70 percent reduction in the Nuclear/CCS scenario. The eUtah cost of almost completely eliminating CO_2 emissions is $94 per metric ton. All renewable scenarios have embedded the costs of about 15 to 20 percent spilled energy.

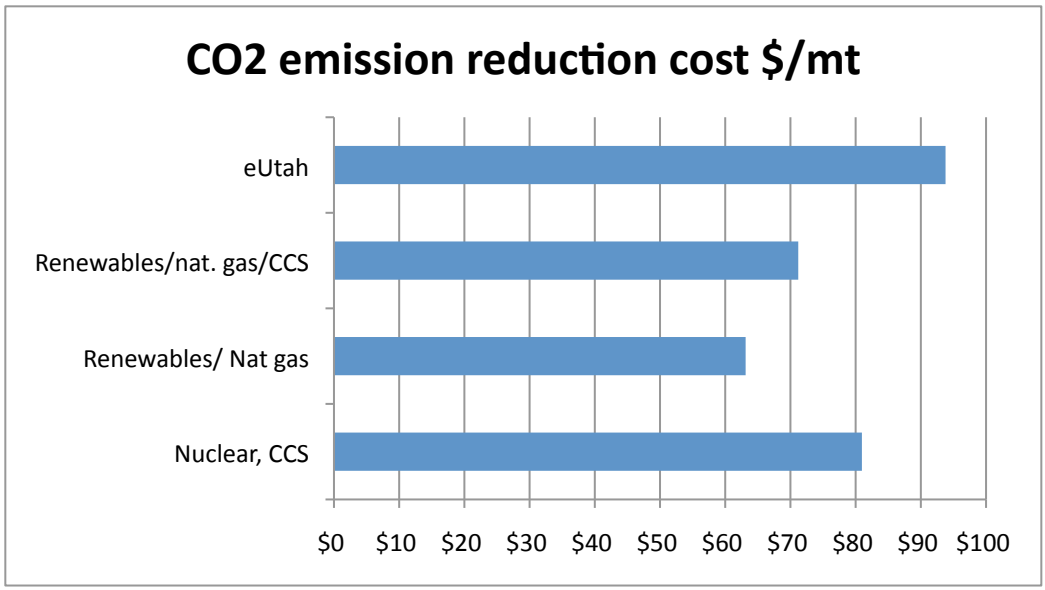

Figure I-4. CO_2 emissions reduction costs, in dollars per metric ton in 2050, with base case cost parameters. The BAU scenario is not shown since CO_2 emissions increase rather than decrease in it.

- **Carbon-emissions-related risks are high**: Continued use of coal without CO_2 emissions controls (BAU) appears much lower in cost if one assumes there is zero cost for carbon emissions. But the risk of carbon-related costs is high. The costs of reducing CO_2 emissions are estimated to be in the $40 to $137 per metric ton range in this study (including the entire range of parameters varied in the sensitivity analysis). For carbon emissions costs of $45 per metric ton, which is toward the low end of this range (and the lowest non-zero value used by PacifiCorp in its IRP), the present value of carbon emissions costs in the 2020 to 2050 period in the BAU scenario would be $10 billion. Figure I-5 shows the present value (in 2010 dollars) of carbon emissions

[9] The cost of spilled energy is estimated at the average cost of solar and wind generation per MWh multiplied by the amount of spilled energy.

costs in the BAU scenario at various levels of carbon prices (or taxes). Of course, this is a heuristic calculation, like the others in this study, designed for insights for investment planning and not forecasts of actual results. These results indicate that a policy of continued reliance on coal with no provision for carbon storage carries a high risk. This risk is reflected in current investment practices among many utilities (including PacifiCorp) which, for the most part, are focusing on natural gas combined cycle plants and wind energy rather than on coal.

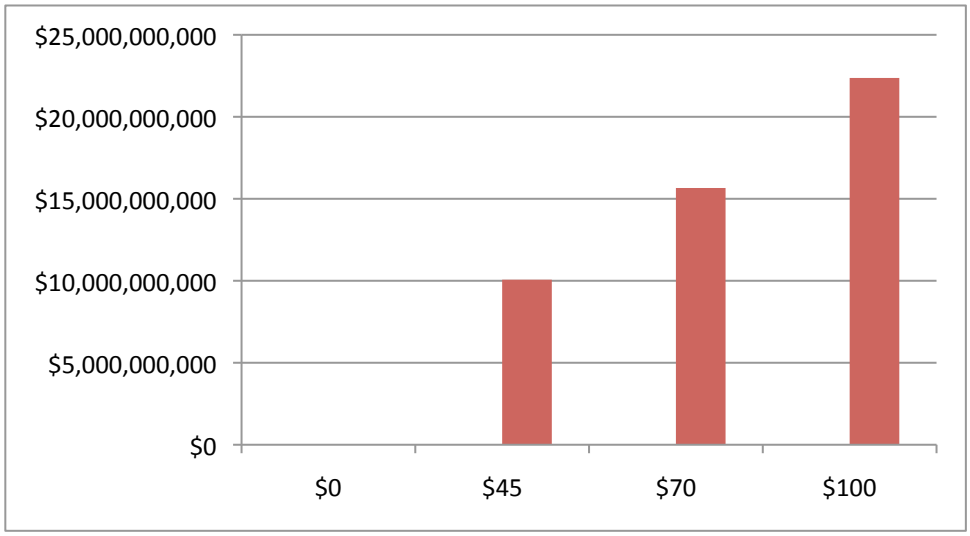

Figure I-5: Present value in 2010 of carbon emissions costs in the 2020 to 2050 period at four prices (or tax levels) CO_2 emissions

When the cost of carbon emissions is added to the BAU scenario, the cost difference between the five scenarios becomes small—well within the variability of the parameters such as fuel cost and capital cost of power plants. Adding $50 per metric ton to emissions in each scenario, the difference in generation cost per person between the BAU scenario and the Renewables/Natural Gas scenario is only $67 in the year 2050. See Figure I-6. This is well within the variability of the fuel and capital cost parameters, as will be seen in Chapter VI.

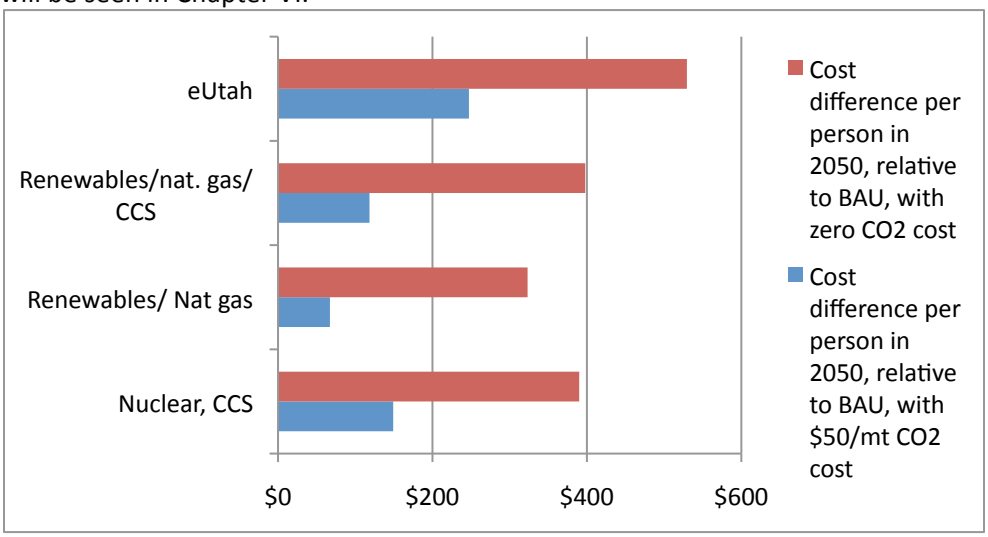

Figure I-6: Cost differences per person in 2050 between BAU and the other scenarios with and without a price on carbon

- **Nuclear power is a high risk approach to reducing CO_2 emissions**: Nuclear power plant unit sizes are large and lead times are long compared to other types of generation. Even if one largely ignores the large unit size (as has been done in this study), the peak amount of capital committed to ongoing nuclear projects would be about twice as large as in the Renewables/Natural Gas scenario, assuming that the baseload generation in the Nuclear/CCS scenario is met only by nuclear plants. Further, this higher capital outlay risk does not reflect additional potential problems such as the cost of delays, which have been rife in nuclear power history in the United States. The high risk of nuclear reactors is reflected in the unwillingness of Wall Street to finance them. Figure I-7 shows the total cost of the projects under construction at any time in a nuclear version of the Nuclear/CCS scenario and the Renewables/Natural Gas scenario (see Chapter VII for details).

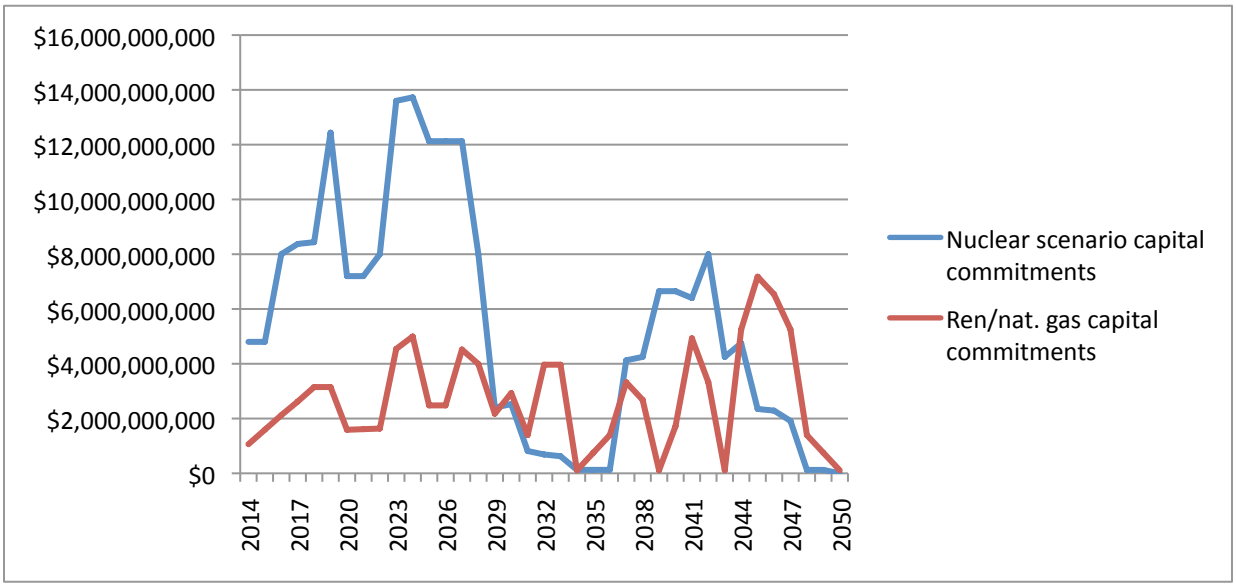

Figure I-7: Capital commitment in any year in the 2014 to 2050 period in the Nuclear/CCS and Renewables/Natural Gas scenarios. All costs are in constant 2010 dollars.

- **Energy efficiency lowers the effective cost of electricity and electricity bills:** There are ample opportunities for reducing electricity use while maintaining the benefits provided, for instance, by having more efficient refrigerators, air conditioners, or television sets. Appliances and building standards supplemented by utility promotion programs are an effective way to have high penetration of efficiency measures and achieve close to the estimated cost savings.
- **Water use is greatest in the Nuclear/CCS scenario and least in the eUtah scenario**: The renewable scenarios would use 15 to 20 billion gallons less water per year than the BAU scenario in the year 2050. The Nuclear/CCS scenario uses more water than BAU due to the high water requirements of carbon capture and storage. This is illustrated in Figure I-8. While the cost of water currently prevailing in large transactions does not indicate a significant cost reduction for the renewable energy scenarios, the opportunity cost of water could be very high. Utah population is growing more rapidly than the rest of the country and the pressure on water resources is already considerable. Moreover, water-intensive technologies carry a greater risk of not being able to meet generation expectations in times of prolonged drought. Wet cooling for geothermal plants is the main water use in the renewable scenarios. Wet (rather than dry)

cooling is assumed because without cooling water, geothermal plants must be operated at much below rated capacity in hot weather..

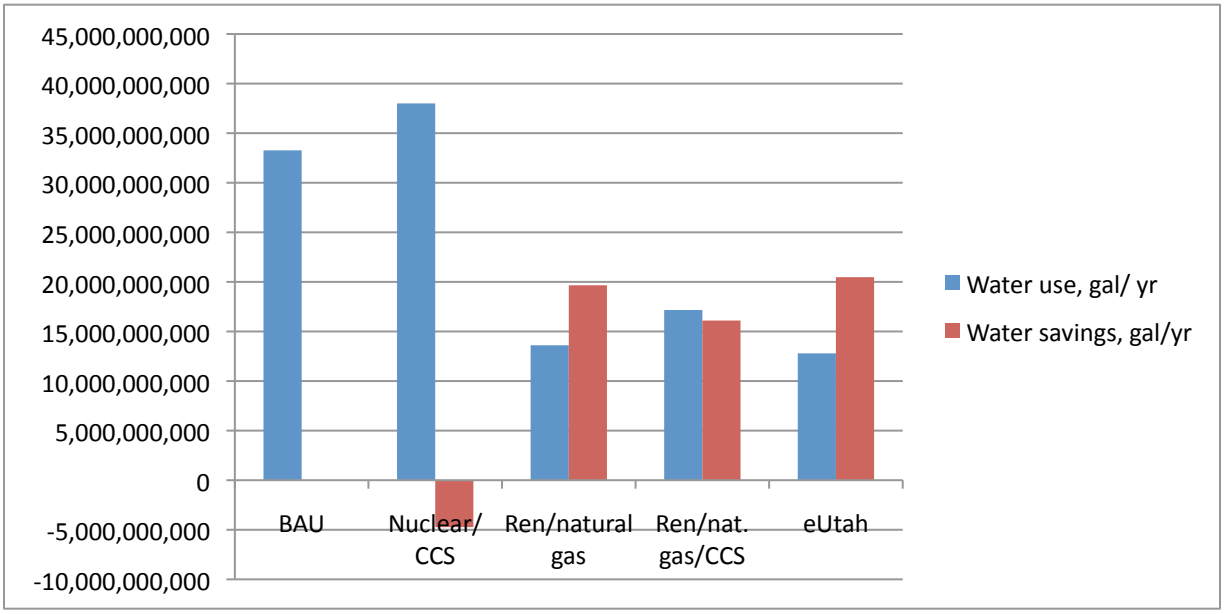

Figure I-8: Water use in 2050 in the various scenarios. Negative numbers mean increases in water use relative to BAU.

A few technical notes are needed to put the study in perspective:

- **Compressed air energy storage** (CAES) has been used commercially for decades on a large scale with coal-fired power plants in two locations: Germany and Alabama. Compressed natural gas storage in caverns and aquifers is also a standard technology. CAES is the only commercial storage technology at present that could be used in Utah on a large scale. Many potential sites are available; one is currently being developed (by Magnum Gas Storage). The basic approach is as follows: when electricity generation is greater than demand, the surplus is used to compress air which is stored in an underground cavern. When generation is less than demand, pressurized air is withdrawn from storage, heated with natural gas, and used to drive a turbine. Figures I-9 and I-10 show the electricity demand during a winter and a summer week in 2003[10] and the electricity supply, had generation been provided by the same mix as the eUtah scenario.

[10] 2003 demand data and renewable energy data from around that year were used to design the renewable energy and storage mix.

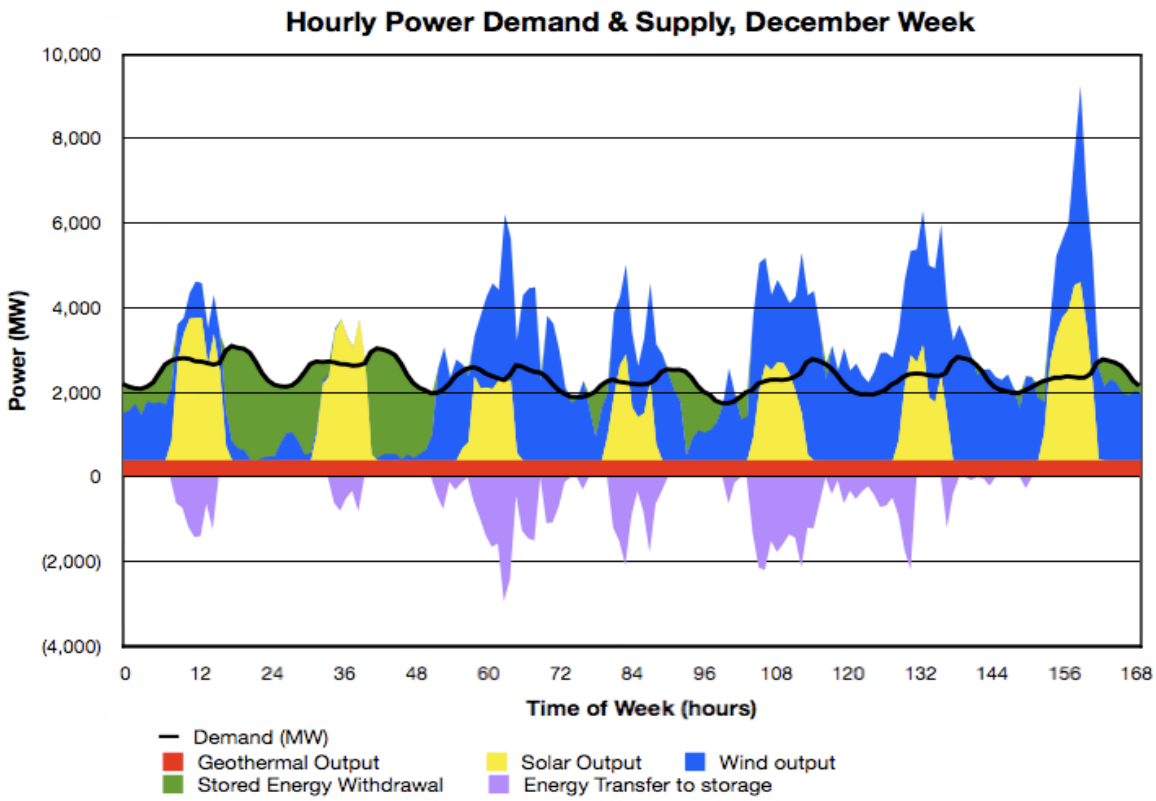

Figure I-9: A week in December 2003 with the eUtah supply and storage configuration. The storage system is assumed to be 75 percent efficient.

Note that there is some amount of spilled energy in the December week. In almost the whole week surpluses of generation over demand are used to compress air into storage, seen below the X-axis in Figure I-9. However, wind and solar energy increase at the end of the week, resulting in spilled energy. There is much more spilled energy in the summer week. This can be seen in Figure I-10, from the many hours in which there are substantial surpluses over demand but no corresponding additions to storage below the X-axis.

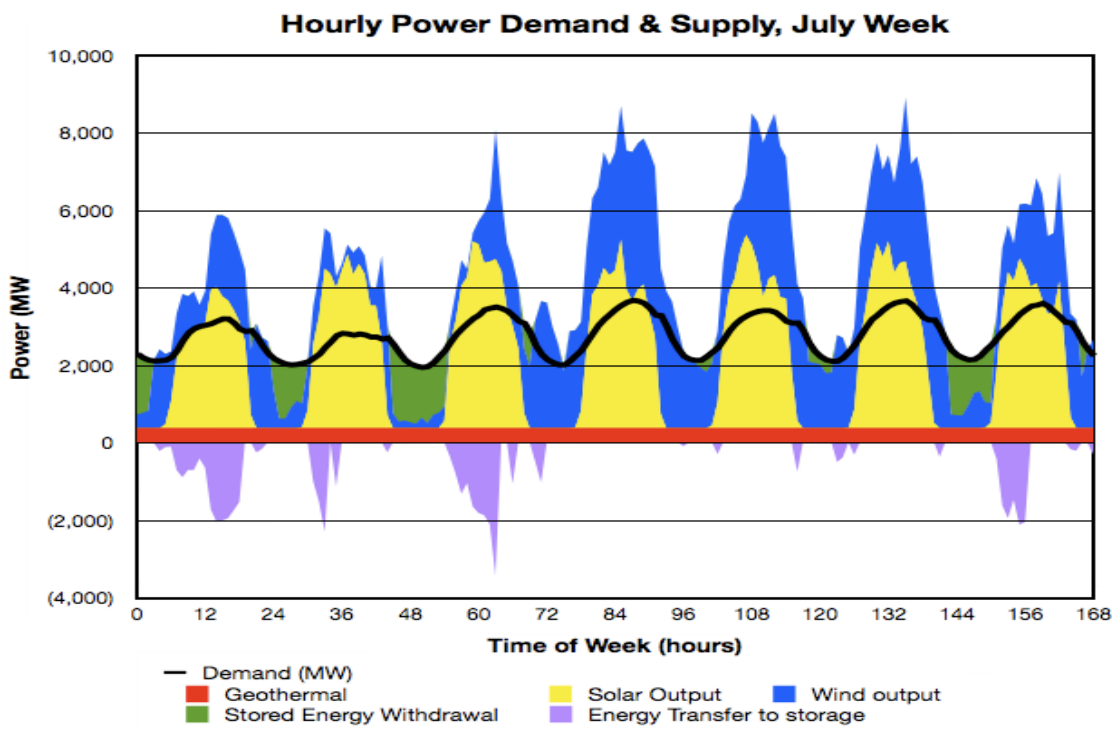

Figure I-10: A week in July 2003 with eUtah supply and storage configuration

- **The risk of coal with CCS** cannot be easily evaluated at this time. It will depend on the scale of storage reservoirs and associated CO_2 pipeline infrastructure as well as the lead time required. We assume, based on available literature, that coal with CCS and nuclear costs are comparable.
- **Optimizing investments between the generation and demand sides of the system** is important, for instance, by building up demand dispatch capability. This could reduce relational system peaks and hence also spilled energy in an electricity system with a high proportion of solar and wind. Integrating highly efficient structures, such as passive buildings, could also do the same, if the overall system is properly designed. But if it is not, there could be higher costs and complications. For instance, zero net energy buildings would normally have a low energy footprint and have solar photovoltaic generation. This would reduce demand on centralized generation in the summer. Yet, the relational system peak problem in a system with high renewables may not occur at that time. Least cost investment approaches will require much more integration of investments in the demand, generation, and storage elements at all levels from small to centralized than is typical at present. Finally, using centralized storage without demand dispatch, local storage elements, etc., creates a need for very large centralized CAES storage system and, potentially, siting problems.

B. Recommendations

The study indicates three critical areas of action in the near future that will set the direction for a flexible, cost-effective, reliable, clean, and low-risk electricity system for Utah, and one that will strategically use its ample renewable resources:

1. **Put in place stringent building and appliance standards that reflect the potential for efficiency to reduce electricity bills**. This is part of the foundation for moving towards a future electricity sector that will be reliable, economical, and low risk both financially and environmentally. The University of Utah is already pointing the way with its standards for new buildings. Those could be a starting point for the commercial sector, with gradual further strengthening between now and 2030. We have not evaluated in detail the goal of the American Institute of Architects which has endorsed achievement of zero net energy buildings (residential and commercial) by 2030. A careful, Utah-specific study of its feasibility for new buildings is highly desirable, especially if done in combination with the design of a 21st century electricity system (see recommendation 3).
2. **Encourage a direction that is compatible with the Renewables/Natural Gas scenario for centralized generation components.** The short term direction for centralized generation indicated by this study is about the same as that being adopted by many utilities, including PacifiCorp: a focus on wind and combined cycle natural gas plants. It is a reasonable way to approach the electricity sector at a low level of risk and is compatible with the Renewables/Natural Gas scenario. But it is not sufficient to continue to focus mainly on new centralized generation. PacifiCorp's additions to wind capacity in the 2009 to 2020 period are planned to total more than 1,000 MW in its East sector, which includes Utah and Wyoming. Yet it appears to have no active plans to develop compressed air energy storage. Such storage could convert its intermittent wind capacity into a dispatchable resource of several hundred megawatts.
   Since compressed air energy storage is the most economical large-scale storage in the Utah context, it is very important to identify sites, estimate their cost and environmental impact, and conduct economic reviews of their location relative to other future elements in the electricity system, including transmission lines, and solar and wind generating facilities. Some development is already occurring (for instance, the Magnum Gas Storage development near Delta, Utah), but much more needs to be done. An effort similar to the Utah Renewable Energy Zones (UREZ) studies that identified and evaluated renewable energy resources in Utah is warranted. Besides being the lowest cost low CO_2 scenario, the Renewables/Natural Gas scenario has the least financial risk. Moreover, it is compatible with a variety of levels of CO_2 reduction, including more than 90 percent, either via the addition of CCS to combined cycle plants and/or incorporating a larger proportion of renewables instead of natural gas combined cycle plants in the long-term.
3. **Lay the foundation for a low-risk, clean, reliable, 21st century renewable electricity system:** Utah has ample renewable energy resources—greater than its own foreseeable electricity needs. Developing them would be a great boost to the state's economy, especially since the coal reserves in existing mines are rather limited (about 12 years' supply at current rates of consumption). This has been recognized in the draft of the Governor's Utah Energy Initiative: "Given the current situation with coal as a primary fuel for base-load electric generation, Utah needs to develop every viable renewable energy project it can identify."[11] Among the potential renewable resources identified in the draft are 7,800 megawatts of roof-top solar photovoltaics, about half of which are commercial rooftops.[12] This distributed solar capacity is nearly 40 percent larger than the solar generation capacity in the year 2050 in the Renewables/Natural Gas scenario. Integrating any significant fraction of this distributed generation into the grid in

[11] Utah Energy Initiative Draft 2010 p. 9
[12] Utah Energy Initiative Draft 2010 p. 9 and Navigant 2004 p. 82

an economical manner (assuming the costs of solar PV decline as widely anticipated) will require new concepts of the grid to be tested, modeled, and implemented, including: (i) pilot projects that will provide field data for models, such as local battery storage and highly instrumented passive buildings that also have local generation, (ii) pilot projects for demand dispatch that can reduce the costs of relational system peak, and (iii) development of models that integrate a variety of elements such as existing buildings, passive buildings, smart appliances, demand dispatch, and generation and storage at all levels from local to centralized. Another way to state the need for this is to note the huge costs of spilled energy in the scenarios with renewable energy (15 to 20 percent of the total generation cost by 2050). Despite this, the Renewables/natural gas is lowest in cost and risk among those reducing CO_2 emissions. If the elimination of spilled energy could be accomplished at modest cost, the cost increase in of a residential bill 100 percent renewable energy could be on the order of $100 per person per year by 2050—in an economy that would have grown from a per person gross domestic production of about $37,000 in 2010 to over $76,000 in 2050. The economy that achieves this goal will not only have a clean, distributed and efficient electricity system, but will also be have the technological leadership in the electricity sector.

Two complementary efforts could accomplish this goal and extend Utah's leadership in technology and energy in a broad and exciting direction:

i. **Create a demonstration city for a renewable, efficient, intelligent electricity system**. A medium-sized Utah city that is already pioneering new ideas in renewable energy would probably be ideal. For instance, St. George is located in an excellent area for local solar energy generation. The City of St. George, together with Dixie Escalante Electric, the local electric cooperative, have pioneered a solar PV program in which individual homeowners can purchase a piece of a larger solar PV system built by the City and the Dixie Escalante.[13] This provides economies of scale to individuals because purchases can be as low as half-a-kilowatt (peak) but the installation is hundreds of kilowatts. It also provides portability of the PV if the owner moves. The City and its utility have done extensive work in setting up this program. St. George could, should it agree, be a laboratory for developing a renewable, efficient, intelligent electricity system (in all or part of the city). In any case, a demonstration city (or a part of a city that is large enough to test the concepts and provide reliable data but small enough for the cost to be manageable) is needed to avoid the kinds of pitfalls that have affected some initial efforts at developing a "smart grid," notably around the installation of "smart" meters.

ii. **Create a Twenty-First Century Electricity Center**. The University of Utah is among the leading public universities in the United States and a leader in energy research. As noted in this report, it also has a sustainability program, which includes highly efficient new buildings. A Twenty-First Century Electricity Center at the University could provide the leadership and intellectual heft that will be needed to develop pilot projects, to make sense of the data, and to develop and refine the models that will guide the way to

[13] See the Dixie Escalante website at http://www.dixiepower.com/services-programs/SunSmart-Solar-Farm and the SunSmart website at http://www.sgsunsmart.com/index.htm.

a cost-efficient renewable electricity system that has distributed as well as centralized elements, and that is founded in an efficient consuming sector that communicates with production and storage centers. Direction could come from an advisory board comprised of representatives from state, utility, industrial, construction, and architectural experts as well as members from other Utah academic institutions and from non-governmental organizations. Sponsorship of such a Center by USTAR, a state agency that is already in the thick of bringing advanced technology leadership to Utah, might help bring together the diversity of expertise areas needed in such a Center.

Other recommendations include:

- Development of at least 200 megawatts of Utah's large geothermal capacity should be considered by PacifiCorp and/or other utilities and companies in the state. Geothermal energy is an important component of reducing the cost of low CO_2 approaches and increasing the fraction of renewable electricity in Utah.
- Carbon capture and storage (CCS) with natural gas combined cycle plants has not historically been considered a priority. It should be. Utah is already a leader in CCS technology research and development with coal—and it makes sense to add CCS with new and existing natural gas combined cycle power plants to this portfolio. Conversion of existing natural gas combined cycle power plants may be more economical than converting existing coal-fired power plants. This study indicates that within the framework of a central station generation approach, a combination of renewable energy sources and natural gas with CCS would be the most economical approach to an electricity sector with very low CO_2 emissions. Natural gas with CCS is a relatively neglected topic relative to CCS with coal; adding it as a major focus of Utah's CCS program could catapult Utah into the forefront of CCS development. This recommendation is germane in the present context because utilities are now investing in combined cycle plants in preference to coal and nuclear. A pilot project to retrofit an existing combined cycle plant should be considered as part of the Utah CCS R&D program.
- Since nuclear power is the most risky element in options for the supply side, and since Utah stands no realistic chance of getting loan guarantees in the foreseeable future, there is no particular reason to maintain it as part of integrated resource planning except perhaps to follow convention.[14]
- A more detailed analysis of several issues connected to a transition from the present coal-dependent electricity sector to a renewable sector is needed, including health benefits, more detailed analysis of water use related benefits, and job creation and training, especially in coal mining areas of Utah.
- Utah could consider exporting solar energy to Wyoming and importing wind energy from there. In any case, most of the area is in the service territory of PacifiCorp, which already relies on Wyoming wind preferentially due to lower cost. The overall cost reduction by swapping Utah

[14] Proponents of small modular reactors claim that the high risks of long lead time, large unit size and high per unit capital cost, the combination of which causes nuclear to be the highest risk technology, could change with their approach. While there is merit in some of their arguments, the downsides which have not been much discussed, are significant; the fulfillment of the cost and risk promises will be difficult, if it is all possible. It will be some time before the claims can be tested; nuclear can always be reconsidered if the claims are proven. See Makhijani and Boyd 2010.

wind resources for Wyoming wind resources would be about $530 million dollars per year in the eUtah scenario in 2050, or almost $90 per person per year.

- Since solar energy is better matched to demand than wind energy, storage costs and requirements are reduced when wind and solar are combined. Further, the storage requirements and spilled energy may also be reduced by the higher capacity factor of wind energy in Wyoming. A study looking at the long term planning with wind largely from Wyoming and solar mainly from Utah for both states would be beneficial. A very substantial reduction in costs (possibly on the order of 10 to 20 percent) would likely be accomplished for all renewable energy scenarios modeled in this study using such an approach.

II. Purpose of the Study

A. Introduction

The energy sector has been in turmoil since the Organization of Petroleum Exporting Countries dramatically and suddenly increased oil prices in October 1973 and its Arab government members imposed an oil embargo on the West (in the context of the Arab-Israeli war taking place in that month). Uncertainty has been the one constant and that seems set to continue, with continued high investment risk as its companion. This study about the future of the electricity sector in Utah examines how options might be opened up in a perilous landscape that would allow for lowering the uncertainty and investment risk in an area that is vital to economic health.

It is useful to briefly survey the risk landscape since 1973, though much of it is well known. In addition to providing a historical basis and context for this report, such a review allows us to discern whether there are any reliable guides that can aid planning to prevent this study from becoming a series of scenarios from which one must pick one according to the passions that may seize the fuel and financial markets at any particular time.

Fossil fuel prices have increased greatly since 1973 only to fall back close to historic lows (in constant dollar terms). Uranium prices have sometimes mimicked the rise and fall of oil prices. Natural gas prices have been almost as volatile. More than 100 nuclear power plants were cancelled in the 1970s and 1980s, leading *Forbes* to do a 1985 cover story that concluded "[t]he failure of the U.S. nuclear power program ranks as the largest managerial disaster in business history, a disaster on a monumental scale."[15] Underlying this problem was the fact that the relationship of energy growth to economic growth, including electricity growth, changed suddenly in the 1973-1974 period, yet it was not properly reflected in construction plans of many utilities for a numbers of years. That change has endured and continued more gradually (see Chapter IV).

All of the risks associated with investment in the energy sector continue today. Just within the last ten years oil and gas prices have gone from very low to very high to somewhere in between (with natural gas prices being less unsteady and on the lower side). Some of the risks, such as war and political turmoil in the Middle East, have intensified.

New ones have been added. The prices of commodities, like copper, as well as of heavy construction, such as that of power plants, have increased rapidly in recent years, in part due to the unprecedented sustained economic growth in China, the world's most populous country, at rates of around 10 percent per year—with industrial growth at even higher rates. What will be the global impact on energy supply if China continues to double the size of its economy every seven or eight years?

Carbon constraints add another element of risk. Will there be significant constraints arising from expectations of climate change? What kinds of costs will they imply for the electricity system? The

[15] Forbes 1985, cover

extent and nature of those constraints is highly uncertain at least in the United States. The country went from the 2009 House of Representatives' passage of a bill requiring an 83 percent reduction in greenhouse gases, relative to 2005 by 2050, to a collapse in the Senate of any agreement to restrain emissions by any magnitude in 2010. In the meantime, the Environmental Protection Agency (EPA) is preparing plans to regulate large sources of CO_2 emissions using its authority under the Clean Air Act, but there is a question of how broad that authority will be in the future and even whether it will remain. There is considerable political sentiment in Congress to take it away. The overall carbon-related financial risk could be potentially much greater than, say, fluctuations in natural gas prices.

Costs attached to carbon dioxide emissions in the next couple of decades could be anywhere from near-zero to $100 or more per metric ton; there is no reliable way to make a forecast. The latter figure would mean a cost of roughly $2 billion per year for carbon emissions of the Utah portion of PacifiCorp at the present annual emissions rate; this is about double the total cost of generation in 2010 (not including transmission and distribution). Up to now, the most stable aspect of the U.S. electricity sector has been the price of coal (see Figure II-1)—the fluctuation of the average annual coal price about the mean since about 1990 has been only about $5 per short ton, or about twenty five cents per million Btu compared to a few dollars per million Btu for natural gas. Coal is by far the largest domestically produced source of fuel for U.S. electricity generation (about half of the total). But it is now subject to the largest uncertainties and potentially also the largest financial risks and volatility. Even in the absence of a national carbon price, the uncertainty has resulted in the cancellation of dozens of coal-fired power plants in the United States.

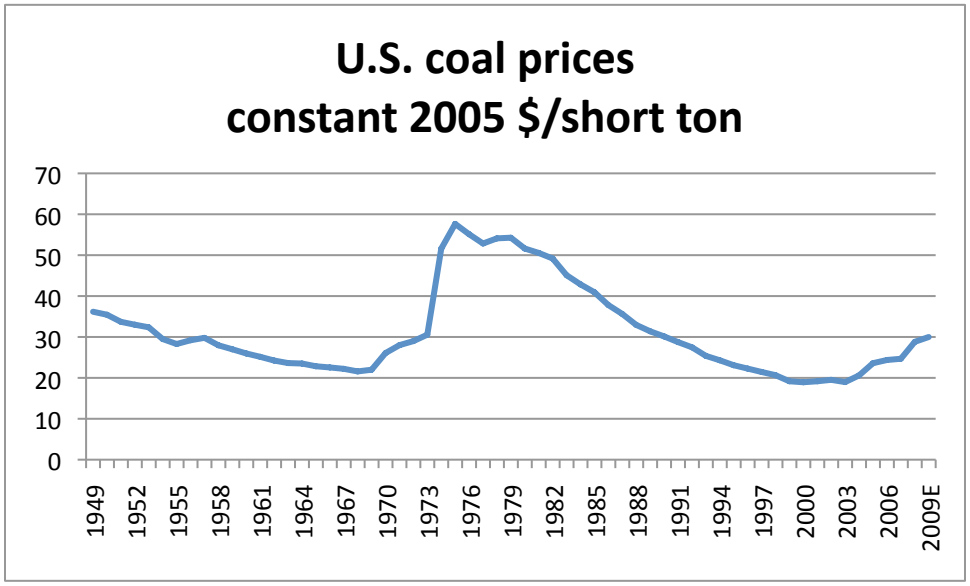

Figure II-1: U.S. coal prices, 1949 to 2009, averaged over all types of coal, in constant 2005 dollars. Source: Energy Information Administration. See the historical coal price spreadsheet at http://www.eia.doe.gov/aer/coal.html.

A few years ago, a nuclear renaissance was widely forecast, in part because it was seen as a viable way to contribute to displacing coal and reducing carbon dioxide (CO_2) emissions from the electricity sector. Yet, it is now literally impossible to finance nuclear power plants in the private sector without very large ratepayer and/or taxpayer subsidies and guarantees. This may be in part due to lack of a firm public

policy regarding sufficient restraints on CO_2 emissions; ironically, it is the other side of the same uncertainty that has resulted in the cancellation of dozens of coal projects. With the defeat of the Proposition 23 to drastically modify California's climate law, the prospects for coal are even more uncertain, at least in much of the Western United States.[16]

Yet, all is not as grim as it might appear. California is pursuing a Renewable Portfolio Standard of 33 percent by 2020. This has created a large number of orders for new renewable electricity generation, including central station solar photovoltaic and concentrating solar power plants. In the past two decades, wind turbines have become a large commercial industry in the United States and around the world, with about 10,000 megawatts installed in the United States alone in 2009.[17] Wind-generated electricity is now less expensive than nuclear, when all costs are taken into account.[18] Further, while the costs of most generating technologies have risen in the past half-decade, the costs of solar-generating electricity have been coming down rapidly, though still high in comparison with wind and coal. From Google to the Department of Energy there is not only a widespread anticipation that costs of solar PV can be brought down, but that they will achieve cost parity with conventional (essentially, fossil fuel) sources of electricity.[19] A similar potential appears to be in store for concentrating solar power, from central station power plants that are now being ordered in the thousands of megawatts to local ten-kilowatt Stirling engine electric generators for commercial buildings, given suitable policies to develop and deploy them in the next ten years. It is possible that California's goal of 33 percent renewable electricity by 2030 may constitute the core of such a policy.

Then there is the old standby: efficiency. The energy problems of the United States would be a lot worse and possibly intractable had not the rate of energy growth per unit of economic growth declined sharply over the past four decades. Had energy growth continued its relationship to economic growth prior to 1973 in the period after that, U.S. energy consumption would have been about two-thirds higher than it was in 2007. Even greater gains are possible with today's technology, but a variety of factors have so far prevented their realization.

In addition, there are new technologies and methods emerging, such as design of passive buildings that reduce their energy footprint by as much as 70 percent. While the practice of building such structures is still in its infancy in the United States, 25,000 such buildings, constructed to strict verifiable standards, including single family homes, apartment buildings, schools, and office buildings have been built in Europe.[20]

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[16] California has more than half the population in the U.S. portion of the Western Interconnection. Calculated from Statistical Abstract 2010 Population.

[17] AWEA 2010

[18] All cost estimates in this study are market-based estimates to the extent possible. Estimated costs do not include production tax credits, loan guarantees, investment tax credits, or other subsidies. Indirect subsidies, notably the limitation of liability for nuclear power plant operators under the Price-Anderson Act is not taken into account. We have also not included external costs, such as health-related damages caused by air pollution, etc. These issues are discussed further in Chapter VI.

[19] The Department of Energy's R&D goal is grid parity by 2015. (DOE 2010a) The search engine company Google has a large program that aims to help develop "utility scale renewable energy cheaper than coal (RE<C) and accelerating the commercialization of plug-in vehicles…." See Google 2010. The "C" in "RE<C" stands for coal.

[20] Zeller 2010. According to this *New York Times* article, only 13 such passive homes, certified as such by design and measurements, existed in the United States in mid-2010.

We should note that some aspects of technological change can reduce uncertainty, but some may add to it. The ensemble of new possibilities could make the overall electricity sector more reliable while keeping it affordable or it could complicate matters considerably, especially if coherent policies and investments are not forthcoming. For instance, electric cars could add considerably to electricity demand, even at peak times; yet electric vehicles could also provide an avenue to rapid demand dispatch at times of peak demand that is more efficient and faster than peaking gas turbines.[21] Passive buildings with local generation systems would change the energy and electricity demand landscape (over 70 percent of U.S. electricity is used in buildings); yet, they could also complicate it in the absence of a coherent approach to electricity system design, since millions of local generating stations (combined heat and power, solar photovoltaics on rooftops and parking lots and even over road surfaces, absorption solar heating and cooling systems, etc.) would require a very different level and type of grid management than at present. For instance, in the absence of a coordinated approach to the overall electricity system, large numbers of zero energy buildings could stress the distribution system and also create surpluses of electricity well above the need, but fail to address deficits in low solar and wind periods. An efficient grid will require larger investments on the consumer side of the grid, including in smart appliances, in the distribution system (such as, battery storage on the consumer side of substations), and in creating demand dispatch capability. There would be correspondingly lower investments on the central station and transmission side of the system—if done right, considerable economies could be achieved. At least that should be the goal. In turn, an efficient distributed system could reduce the risk of large financial risk, since many of the investments will be modular.

B. Goals of the study

This study examines the Utah electricity sector by analyzing the portion of it supplied by PacifiCorp (which is about four-fifths of the total). The overall goal is to examine whether and how renewable energy sources, complemented by efficiency, can open up options for reducing risks in electricity sector investments while maintaining the present reliability of the system. Since one of the largest risks is related to future carbon prices, this study examines several scenarios to greatly reduce or nearly eliminate CO_2 emissions from the electricity sector. The scenarios and related sensitivity analysis also illustrate the potential impacts of other uncertainties, such as those in natural gas prices or capital costs or nuclear and renewable electricity systems. We do not assume a carbon price to try to determine a generation portfolio. Rather, we use five different generation portfolios to determine the implications for costs of reducing carbon. These scenarios are rather different from each other in their financial and technological risks. Our approach can therefore be used to examine which approaches to electricity system design might provide the significant flexibility at a modest cost in order to reduce overall investment and carbon price risks that confront the electricity sector.

The more detailed goals of this study are to:

1. Examine the feasiblity of large scale replacement of fossil fuels by renewable resources in Utah's electricity sector, including one scenario that essentially completely eliminates fossil fuels by 2050.

[21] Brooks et al. 2010. Demand dispatch means aggregating many consuming devices that can be cut off by prior agreement with the consumers at times of peak demand (or relational system peak in a renewable system) and restored. In some cases this can be done more quickly and efficiently than starting up peaking turbines. Demand dispatch is much like present-day air-conditioner cycling programs, but could be organized by independent companies for offer on the spot market in competition with other peak generation resources.

2. Estimate the cost of making the transition to renewable energy sources.
3. Compare this cost to other approaches, including an approach that would rely on conventional sources—nuclear, gas turbine combined cycle plants fueled by natural gas (GTCC), coal with carbon capture and storage (CCS) and single stage gas turbines.
4. Do sensitivity calculations indicating the uncertainties related to capital and fuel costs associated with new power plants.
5. Compare all of these in terms of cost and carbon dioxide emissions with a business-as-usual approach based on the assumption of no restraints on carbon dioxide emissions.
6. Compare the amount and fraction of household income that would be devoted directly and indirectly to electricity generation in Utah under the various scenarios.
7. Briefly discuss the investment risks associated with various approaches to reducing CO_2 to examine whether one or more approaches can greatly reduce these risks by increasing flexibility of investment response at any given time.
8. Examine how approaches to electricity that are primarily oriented to renewable energy may fare in terms of risk.
9. Compare water use for different approaches to electricity generation systems.
10. Examine the lessons of the above exercise for state-level policy on electricity.

This is a study that examines options. As such it is not a prescription for investments. Rather the scenarios have been structured so as to allow clear comparisons between overall approaches to electricity sector investments (including varying levels of efficiency). For instance, the scenario that is called "business-as-usual" does not purport to be an integrated resource plan that PacifiCorp or any other Utah electricity supplier might devise. It is a scenario that assumes that retired coal-fired power plants will be replaced by new ones. This scenario allows assessment of the risks of a coal-oriented investment strategy as well as the costs of eliminating CO_2 per metric ton and per year in the low-CO_2-emissions scenarios.

All scenarios, including renewable-energy-oriented scenarios, are based on central station generation and centralized storage. A single storage technology, compressed air energy storage (CAES), which is commercial today, is used to develop the renewable energy scenarios. Decentralized generation, distributed generation, intelligent (or smart) grid technology are not included in the quantitative analysis. An intelligent grid would allow many loads to be matched to the availability of renewable energy. It would allow for loads to be aggregated and demand reduction to be dispatched in a manner similar to the operation of present peaking generation, such as hydropower plants and single-stage gas turbines.[22] In effect, there is no optimization between investments on the demand and consumer side of the electricity system and the centralized generation side. As we shall see in Chapters V and VI, a purely centralized renewable system dominated by wind and solar results in a great deal of spilled energy. The cost of spilled energy in the eUtah scenario in the year 2050 amounts to about 20 percent of the total cost.

In this study we introduce a new concept that will be essential to the design of grids with a very high proportion of renewable energy. Instead of peak load, which is determined by the consuming sector alone, with generation facilities built to meet that demand, we have a very different and difficult issue. The installed generation and storage capacity in a solar-and-wind-dominated grid is determined by the relationship between the availability of wind and solar energy and the amount of energy in storage at any particular time. Hence, we will see that the time that determines the capacity and storage

[22] Brooks et al. 2010.

requirements in the eUtah scenario is no longer the summer late afternoon-early evening load when lighting and air-conditioning determine how much generation capacity will be needed. Rather, the times of greatest stress tend to occur in the winter during prolonged periods of relatively low wind. Of course, solar energy supply is naturally low at that time. Hence a solar-and-wind-dominated electricity system has a *relational system peak*—determined by the relationship of a variable demand to a variable supply. Moreover, the time of this relational system peak can be expected to vary from one year to the next.

Finally, breakthrough technologies are not included. These include large scale electricity storage in batteries and solar-driven absorption heating and air-conditioning which is in the early stages of commercialization in some parts of the world.[23] Since it is likely that many new technologies will be employed in the electricity sector (generation, storage, demand, efficiency) in the next few decades, the scenarios are a way to identify options and directions for investment and risk reduction rather than prescriptions or projections of the shape of things to come over several decades.

In view of the above, the framework for this analysis is as follows:

1. We use Utah's PacifiCorp demand data for one year and projections to 2020 as the starting point of the study. PacifiCorp provides about 80 percent of Utah's electricity demand.
2. We use population and household projection data as compiled and projected by the state.
3. The relationship between economic growth, population growth, and electricity growth is based on an analysis of historical trends. Efficiency considerations are superimposed on these trends.
4. Cost of upgrades to existing coal-fired plants and required pollution abatements are not included in the projections. Considerable investments are likely to be required.
5. We do not attempt to assume a price on CO_2 emissions as the basis of the scenarios, except an implicit zero price (or tax) in the business-as-usual scenario. Rather our aim is to estimate costs based on parameters for which data and projections are available and calculate a cost for reducing CO_2 emissions. This is a principal element used to compare scenarios, in addition to total, per person, and per household cost. The financial risk of continued reliance on coal are assessed at various carbon prices in the 2020 to 2050 period.
6. Simplifying assumptions are used, notably a single techology for implementing solar—concentrating solar power (CSP) with dry cooling. Declining solar PV costs may mean that low energy footprint buildings using local solar PV as part of new construction could change the demand picture considerably so far as centralized generation goes.

It is important to note that since this is a technical study, it does not assume any changes in lifestyles. Hence, the assumptions about the services that electricity provides, such as lighting, cooling, cooking, or operating a host of appliances, are assumed to be the same in all scenarios and to grow with the economy. Different amounts of electricity used in the various scenarios reflect different levels of efficiency, with expenditures needed to achieve those levels of efficiency.

C. Why a 100 percent renewable scenario?

At a time when Congress has not passed legislation mandating even modest reductions in U.S. greenhouse gas emissions, it is natural to raise the question of why this study includes scenarios that examine near complete elimnation of CO_2 emissions from the Utah electricity sector.

[23] See http://www.climatewell.com.

There is broad, though evidently not universal, agreement that reducing global greenhouse gas emissions by 50 to 85 percent relative to 2000 by the year 2050 will be essential to keeping the estimated global average temperature increase to about 2 ^{o}C (3.6 ^{o}F). A 50 percent reduction level will provide a low probability of achieving that goal, while an 85 percent reduction is estimated to achieve it with a high probability (85 percent probability).[24] This would require at least the same level of reductions in the developed countries. A per capita global allocation of greenhouse gas allowances by 2050 would require even greater reductions in developed countries whose present and cumulative emissions per person are much higher than those of the developing countries. A per person allocation of emissions allowances would mean that a global 50 percent reduction would require an 88 percent reduction for the United States and a global 85 percent reduction would translate into a 96 percent U.S. reduction.[25]

Even though there is no global treaty on specific reduction targets, addressing climate issues in the context of keeping the temperature rise to below 2 ^{o}C was part of the final declaration of the Copenhagen Conference of the Parties to the United Nations Framework Convention on Climate Change.[26] The United States has been a party to this treaty since 1994. This is the context in which official global discourse on greenhouse gases is taking place. For instance, an official German study, prepared by the German Advisory Council on the Environment, prefaced its analysis of a 100 percent renewable electricity sector in Germany as follows:

> Climate study findings indicate that Germany and other industrial nations will need to reduce their greenhouse gas emissions by 80 to 95 percent by 2050 (IPCC 2007)—a goal that was officially endorsed by the Council of the European Union in October 2009 (Council of the European Union 2009). Germany's ambitious environmental goals are backed by broad and nonpartisan support from all social actors.[27]

Such large scale reductions in greenhouse gas reductions would require signficant reductions from all sectors that have more than a tiny level of emissions. The electricity sector is among the largest emitters of CO_2 globally; it will be essentially impossible to achieve reductions of 80 to 95 plus percent without at least corresponding reductions of emissions in the electricity sector.

There is an economic reason to consider higher reductions in the electricity sector than indicated by the overall level sought. High percentages of reductions in some sectors, such as methane and nitrous oxide emissions from agriculture, may be difficult and costly. The former has a vareity of sources from rice fields to beef, milch, and draft cattle; the use of nitrogen fertilizers is a majour source of the latter. The economic reason was a major part of the rationale for the recent German official scenario of a 100 percent renewable sector for Germany:

> Electricity generation is a key area of Germany's energy and climate policies in view of the fact that this sector currently accounts for roughly 40 percent of national carbon

[24] IPCC 2007 Table SPM.5 (p. 15)
[25] Makhijani 2010a p. 2. A global reduction of just 50 percent in greenhouse gas reductions (broadly regarded as modest at best for climate protection), with allowances allocated on a per person basis would require an 88 percent reduction in the United States.
[26] Copenhagen Accord 2009
[27] German Advisory Council 2010 p. 6

> emissions (UBA 2010). However, ***it is also a sector where carbon emissions could be reduced at a relatively low cost—which means that reducing overall greenhouse gases by only 80 percent by 2050 will necessitate implementation of a completely carbon neutral electricity supply in Germany.***[28]

The electricity sector accounted for about 34 percent of U.S. greenhouse gas emissions in 2008 (40 percent of fossil fuel-related emissions).[29] The scenarios in this report go from about 70 percent CO_2 reductions to 95 percent CO_2 reductions by 2050 (relative to 2010, when CO_2 emissions were about the same as in the year 2000).[30] All of the carbon reduction scenarios are compared to a "business-as-usual" scenario, in which coal-fired power plants without CO_2 emission controls continue to dominate generation.

The context of the entire study is a state-level examination of electricity sector investments. This is because decisions at that level are regulated and overseen (to a greater or lesser extent, depending on the deregulation of generation in a particular state). In the case of Utah, the Public Service Commission has regulatory authorty over the portion of PacifiCorp's plans relating to Utah. PacifiCorp supplies about 80 percent of the electricity requirements of Utah.

[28] German Advisory Council 2010 p. 6, emphasis (italics and bold) added.
[29] EPA 2010 Table ES-2 (pp. ES-4 to ES-6)
[30] For U.S. greenhouse gas emissions data see EPA 2010.

III. Renewable Resources in Utah

We used Utah Renewable Energy Zone (UREZ) data - UREZ I and II—mainly UREZ II—for compiling the data of renewable resources at specific locations. Central to our analysis is a data set of renewable generation potential for the state of Utah based on actual meteorological data and zones of high quality resources identified and quantified by the Utah Renewable Energy Zones (UREZ) Task Force. This data captures the variability of solar and wind resources accurately. We have used hourly renewable energy supply averages for each location.

The UREZ II study identifies twenty-seven zones of the most economically feasible wind, solar, and geothermal renewable resources in the state. The total resources identified by UREZ include 14,696 MW of wind and 8,875 MW of solar. We selected six solar zones and twelve wind zones for a total generation capacity of 3,045 MW of wind and 8,167 MW of solar as the "unit" amounts to be fitted (with storage) to the demand curve for 2003. The analysis of the fraction of this "unit" solar and wind capacity that is dispatchable solar and wind when combined with storage for a single year is part of the basis for extending the analysis to the various levels of generation needed out to the year 2050.

The renewable resource data are for various years, but concentrated in the 2000 to 2003 period. The amount of solar generation chosen, 8,167 MW, for the initial Solar Generation Portfolio represents 55 percent of the solar capacity in the state while initial the Wind Generation Portfolio represents 34 percent of the wind capacity identified in UREZ. Our selection decisions were partly constrained by the correlation between the meteorological data sites, but we were successful in selecting sites representative of the varied climates and geographies present in Utah. Where we had the ability to, we favored sites that were located near existing energy resources including transmission and fossil fuel areas.

Table III-1: UREZs included in Solar Generation Portfolio (SGP)[31]

UREZ Solar:	**NSRDB Site:**	**UREZ Capacity (C_z):**	**Zone Area (A_z):**
Clive	Wendover	1876 MW	37.52 km^2
Escalante Valley	Cedar City	2133 MW	42.66 km^2
Grand	Moab	226 MW	4.52 km^2
Intermountain	Delta	1564 MW	31.28 km^2
Red Butte	St. George	1164 MW	23.28 km^2
Wayne	Moab	1204 MW	24.08 km^2
SGP Total Capacity:		**8,167 MW**	**163.34 km^2**
% of Total UREZ Identified Solar Capacity (14,696 MW):			55%

Table III-2: UREZs Included in Wind Generation Portfolio (WGP)[32]

UREZ Name:	**UALP Tower:**	**UREZ Capacity:**
Black Rock	Cricket II	700 MW
Cedar	Elmo	250 MW

[31] NSRDB 1991-2005; UREZ II 2010 Table ES-1 (p. ES-4). "Generating capacity is the maximum power output available from a generator." (UREZ I 2009 p. 11)

[32] UALP (Utah's Anemometer Loan Program): UGS 2010 Site Data; UREZ: UREZ II 2010 Table ES-1 (p. ES-4)

Cedar Creek	Snowville	315 MW
Duchesne	Duchesne	320 MW
Garrison	Garrison	120 MW
Helper	Soldier Summit	480 MW
Milford	Milford	860 MW
WGP Total Capacity:		**3,045 MW**
% of UREZ Total Capacity (8,875 MW):		34%

Figure III-1 is the map prepared for the UREZ task force, which illustrates the geographic diversity of the resources in the eUtah portfolio. The blue shaded areas represent wind energy and the yellow, brown, and red shades represent solar energy.

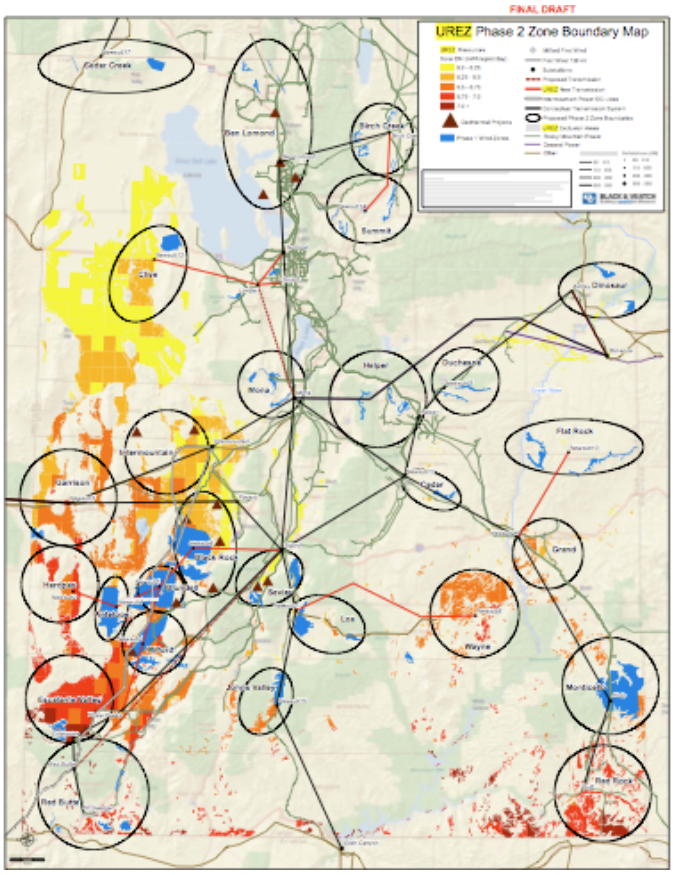

Figure III-1: UREZ Phase II Zone Boundary Map
Source: UREZ II 2010 Figure ES-1 (p. ES-3)

We selected zones to create a dataset from actual observations to represent Utah's generation potential. It is important to note that inclusion of zones on this map is not a siting recommendation, which is beyond the scope of this study. This is an issue that requires considerations far beyond those of a feasibility study of this type.

Each solar and wind zone selected is associated with a meteorological observation station. Hourly data for normally incident solar radiation (DNI – W/m^2) were downloaded from the National Solar Radiation

Data Base (NSRDB) and matched by location to UREZ zones.[33] The resulting dataset, a matrix of hourly values over an entire year (8760 hours) for each zone, was then converted to a table reporting hourly MW of electricity produced by each zone at full capacity. Capacities were taken from the UREZ Task Force Phase II final report document,[34] and calculated based on the conversions used in UREZ Phase I.[35] This hourly solar production data was input into the spreadsheet model that serves as the basis for this study's analysis. This model is described in Chapter V. To put the present discussion of renewable resources in context, we note here that the hourly renewable wind and solar generation are added together with any baseload generation and matched to demand. Surpluses over demand are stored and electricity is generated from storage when the total generation resource falls short. We mix different amounts of solar and wind energy to try to minimize the amount of storage and of installed capacity required to meet the reliability criterion that there must be 12 percent reserve capacity over demand at all times.

A similar process was employed for converting hourly wind speeds to hourly electricity production. Once zones and hourly wind data for the year[36] were paired, wind-shear exponents were calculated from data and formulae presented in UREZ I[37] to convert the speeds to constant hub heights to calculate output at 80 meters consistent with UREZ modeling.[38] These converted wind speeds were converted to power output from the GE 1.5 S turbine using power curve data from the Idaho National Laboratory.[39]

Geothermal energy is included in the study at levels consistent with the projections in the UREZ I and II reports. Specifically, the largest geothermal capacity is 1,000 MW in the eUtah scenario, where use of renewable energy is sought to be maximized. In the Renewables/Natural Gas scenario, 900 MW of geothermal are developed.

UREZ I identifies 2,166 MW of potential geothermal resources in Utah. However, of these 754 MW are identified resources, while 1,413 MW "undiscovered resources," mainly in the Escalante-Sevier-Black Rock area.[40] Generation above 700 MW of geothermal in our scenarios is not brought on line until late in the decade of the 2020s—that is, 15 to 20 years from the present.

Geothermal resources are desirable as renewable resources because they provide the baseload capacity, which make it less complicated to build a centralized renewable generation system. If the full extent of geothermal resources assumed in this report is not available, 200 to 300 MW could be replaced with combined cycle natural gas-fired plants with only a small impact on CO_2 emissions and essentially no impact on costs.

A more detailed discussion of the preparation of the generation data for eUtah can be found in Attachment A.

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[33] NSRDB 1991-2005
[34] UREZ II 2010, Table ES-1 (p. ES-4)
[35] UREZ I 2009 p. 15
[36] UGS 2010 Site Data
[37] UREZ I 2009 Tables 3 to11 (pp. 16 to 22) and p. 47
[38] Elise Brown, Email to Arthur Morris, 10 August 2010
[39] INL GE Wind
[40] UREZ I 2009 Table 12 (p. 28)

IV. Demand Scenarios

A. Introduction

This study uses electricity demand for the portion of Utah serviced by PacifiCorp, which represents about 80 percent of Utah's electricity consumption. As noted in Chapter II, we adopt a conventional economic view and do not assume any changes in lifestyle in any of the scenarios.

Efficiency improvements are technical, resulting in the same provision of the services that electricity provides. For instance, more efficient lamps would provide the same amount of light and more efficient air-conditioners would provide the same amount of cooling but use less electricity in doing so. In the case of demand-side management programs that result in load curtailment, these are assumed to be voluntary, with compensation for load curtailment, as is the present practice.

This analysis is geared to given levels of electricity services as represented by a business-as-usual projection that does not include new efforts and expenditures on efficiency. This allows the generation in the BAU scenario to represent the electricity services in all scenarios. In the other scenarios a part of these requirements is met by efficiency and the rest is met by generation. We calculate the costs per megawatt-hour (MWh) for both generation alone and for providing electricity services.[41]

Within a technical framework, overall electricity consumption and its change over time depends on several factors:

- Total population and population growth rate.
- Economic factors, including economic growth per person and the composition of the economy.
- The relationship of electricity use to population and to economic factors, including efficiency of electricity use for specific economic activities and demographic changes such as changes in number of people per household.

We have used population growth projections made by the State of Utah in 2008 along with the accompanying projections for numbers of households. The latter have grown faster than population, and the trend is expected to continue. Figure IV-1 shows the population project that underlies all the demand projections.

[41] Specifically, if the generation in the BAU scenario is G_b and in the renewable scenario is G_r, efficiency supplies an amount equal to $G_b - G_r$. The cost of generation in the renewable scenario per MWh is $M_{rg} = C_r/G_r$, where C_r is the generation cost. The cost of providing electricity services in the renewable scenario is $M_{sg} = (C_r+C_e)/G_b$, where C_e is the cost of the efficiency measures. A similar calculation is made for the Nuclear/CCS scenario.

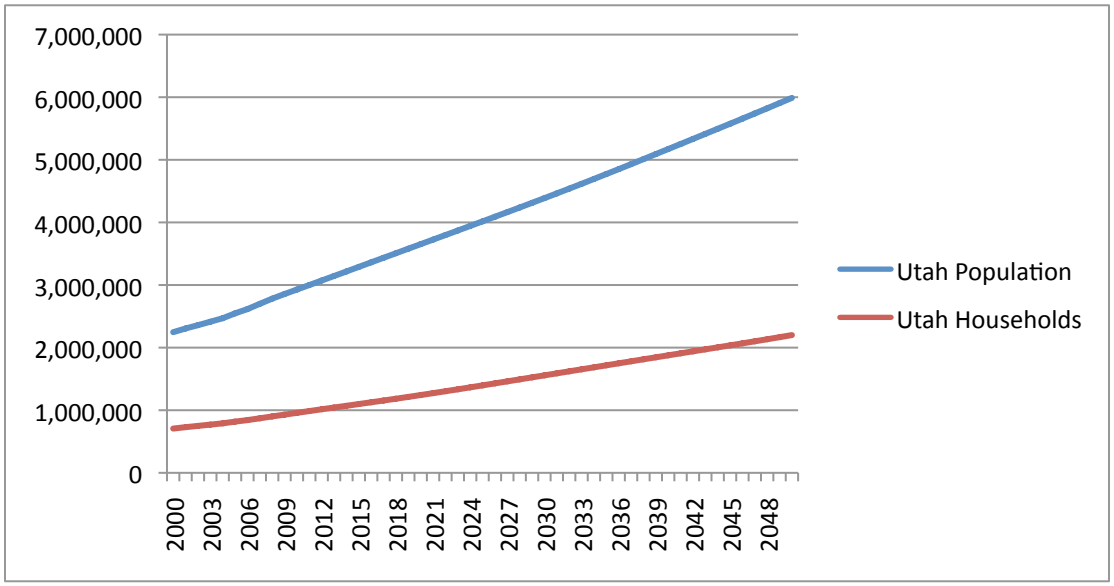

Figure IV-1: Utah population and household numbers (2008 projections)
Source: Utah Governor's Office 2008

As is evident, these are long-term projections that smooth out any effect of recessions and spurts of growth following recessions (which has been the typical pattern in the past). In view of the changes that have occurred over the past four decades in the patterns of electricity growth, it is important to establish the relationships of electricity to economic growth and to population growth, and the trends over that period. Nationally, the relationship of economic growth to electricity growth has been changing rather steadily since the start of the energy crisis in 1973. Prior to that time, electricity grew at about twice the rate of economic growth. That ratio changed to about 1 to 1 in the 1973 to 1989 period; it has declined further to just over one-half to one in the 2000 to 2007 period. Recession years have been excluded in selecting the starting and ending dates. Table IV-1 shows the growth rates and ratios. It also shows that electricity growth has changed nationally with respect to population growth. In the 1950 to 1973 period, the growth rate of electricity was over five times the population growth rate. That ratio was just 1.26 during the 2000 to 2006 period. Electricity growth still appears to be changing in its relationship to population and to the economy.

Table IV-I. Growth rates of electricity, economy, and population in the United States, 1950 to 2007

Period	Electricity growth rate	Economic growth rate	Population growth rate	Ratio Elec/Econ Growth Rate	Ratio Elec/Population growth Rate
1950-1973	7.76%	3.98%	1.45%	1.95	5.35
1973-1989	2.95%	3.00%	1.04%	0.98	2.83
1989-2000	2.28%	3.26%	1.18%	0.70	1.93
2000-2007	1.28%	2.40%	1.02%	0.53	1.26

Source: Calculated from data in the U.S. Statistical Abstract (for population) and the Energy Information Administration (for electricity)

Figure IV-2 shows the trends in the ratios of electricity to economic growth rates and electricity to population growth rates.

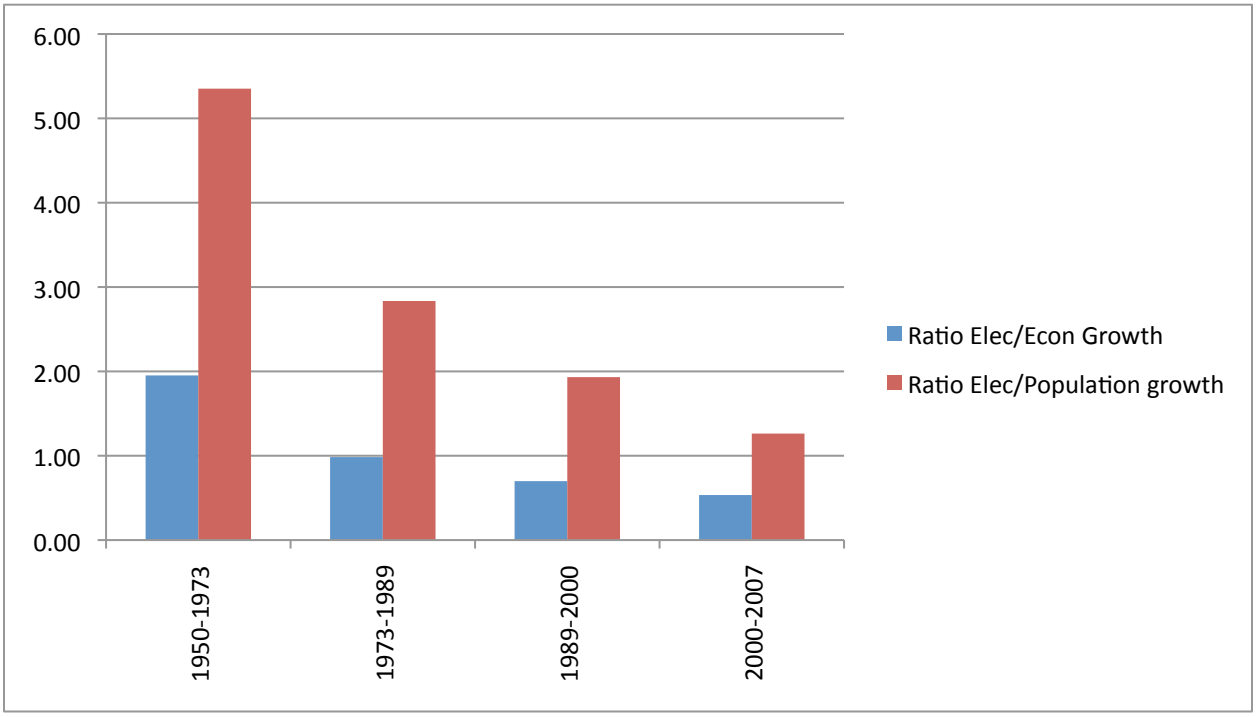

Figure IV-2: Trends in ratios of electricity to economic growth and electricity to population growth. Source: Table IV-1.

These trends show that the U.S. economy and people have been reducing their electricity intensity, even as the share of electricity in the overall energy picture has increased steadily and continues to do so. There are a variety of reasons for these trends, including the oil shocks of the 1970s, more efficient buildings and appliances, more efficient industries, export of energy intensive industries, and a larger share of the economy in the service and information technology sectors. We have kept these trends in mind when examining data for Utah and for PacifiCorp and constructing the scenarios for demand.

B. Demand scenarios

This study incorporates three scenarios for electricity demand. Two of them are based on the PacifiCorp Integrated Resource Plan update of March 2010 (PacifiCorp IRP 2010) and one of them adds higher efficiency for new residential and commercial buildings from 2013 onwards based on an American Institute of Architects' assessment. The PacifiCorp March 2010 assessment includes a recovery from the recession in the 2011 to 2014 period, with growth resuming a more normal pattern after that.

The demand scenarios are:

1. Historical demand projection: No explicit efficiency increases are assumed in electricity projections. This means that induced changes such as through utility efficiency programs or new building and appliance efficiency standards.

2. A medium efficiency/Demand-Side-Management projection based on the March 2010 PacifiCorp update to its IRP. This includes both Class 1 Demand-Side-Management (DSM), where the company directly controls load and efficiency measures (called Class 2 DSM), where load is reduced by more efficient homes, appliances, industries, etc.[42]
3. A high efficiency demand projection with some increases in building efficiency relative to the medium efficiency scenario.

1. Historical demand projection

The historical demand projection is a reference case, suggested by the eUtah Advisory Board. It assumes no carbon restraints and hence no carbon related costs. It implicitly assumes continued cheap electricity and no significant efficiency improvements due to policy or prices. The idea is not to provide a projection but rather a reference case for comparing cost, financial risks, emissions, and water use. This was put together from the PacifiCorp 2008 IRP and the March 2010 update.

The basic approach to projections is derived by combining general national considerations regarding population, economy, and electricity to the trends in Utah. The electricity growth rate is assumed to be slightly greater than population growth for the period under consideration in Utah. It approximately follows PacifiCorp's projection in the 2020 to 2030 period. All values of electricity load are generation numbers and include transmission and distribution losses.

The PacifiCorp projections, given in Tables 3.1 and 3.2 of the March 2010 IRP update have an average load growth between 2010 and 2019 of 2.73 percent and average demand growth rate of 2.58 percent.[43] However, the projections take into account emergence from the recession, with considerably higher load growth than normal in the earlier part of the period (more than 4 percent between 2011 and 2012, for instance, compared to the 2.73 percent average). Growth falls off to less than projected population growth in the latter part of the 2010 to 2019 period (less than 2 percent per year electricity load growth compared to projected population growth of just over 2 percent).

Population growth rates are official State of Utah projections. The 2000 to 2007 historical electricity growth rate for the State of Utah was about the same as population growth rate. Nationally, the electricity growth rate has also been trending towards the population growth rate, though it was still somewhat higher in the 2000 to 2007 period. In view of these facts, and the usual large uncertainties inherent in long-term projections, the BAU projection for load growth beyond 2019 up to 2050 is assumed to be the same as the projected population growth for the State of Utah. BAU demand growth beyond 2019 is projected at the same rate as load growth, though PacifiCorp projections for demand growth are slightly less than for load growth for the 2010 to 2019 period. This is a conservative assumption (i.e., may overestimate demand) relative to the 2010 to 2019 estimates made by PacifiCorp. Overall, this gives an electricity growth rate that is slightly higher than the projected Utah population

[42] Class 1 and 2 DSM refer to designations outlined in the 2008 PacifiCorp Integrated Resource Plan (PacifiCorp IRP 2008 p. 80). Class 1 programs allow the utility to curtail demand when needed. The "Cool Keeper" program is an example of a Class 1 DSM program. Class 2 programs lower demand through retrofits and appliance replacements. A refrigerator replacement program is an example of a Class 2 program. The PacifiCorp IRP is available for download at http://www.pacificorp.com/content/dam/pacificorp/doc/Environment/Environmental_Concerns/Integrated_Resource_Planning_3.pdf.

[43] PacifiCorp IRP 2010 pp. 25-26

growth rate (1.9 percent versus 1.8 percent) for the 2010 to 2050 period. These figures are not adjusted for the effect of DSM programs. The historical demand projection scenario is set up to provide a generation-based reference case for electricity services. That is, we assume here that all growth in electricity services will be provided by growth in central station generation. Just as the coal-replaced-by-coal assumption does not correspond to actual PacifiCorp investment policy, the assumption of no further DSM programs also does not correspond to PacifiCorp policy. It is a reference case that allows the examination of the comparative effects of different policies and their effects on overall costs, household costs, and implicit costs of reducing CO_2 emissions in the other projection, which do take DSM programs into account. Sales for resale are not included in any scenario. Under the historical demand projection, electricity load more than doubles to almost 52 million MWh in 2050 from 24.3 million MWh in 2010.[44]

Specifically, we assume that for the historical demand projection, the ratio of electricity growth rate to economic growth rate remains at 0.53, as indicated by national trends. This is used to derive an economic growth rate for Utah from the electricity projections. This is approximately in line with national trends. The electricity growth rate of about 1.9 percent projected for Utah in the Business-as-Usual case is higher than the national value of 1 percent assumed by the Energy Information Administration for the period from 2010 to 2035.[45] The reason for this is essentially due to a higher population growth rate in Utah. The State of Utah projects an average long-term (to 2050) population growth rate of about 1.8 percent, while the national population growth rate is about one percent lower than that. The Utah economic growth rate used in this study of 3.6 percent is also correspondingly higher than national projections of 2.7 percent[46] due to higher projected Utah population growth.

There is a BAU supply scenario corresponds to the historical demand projection (see Chapter V).

2. Medium efficiency projection

PacifiCorp 2010 provides annual projections for load and demand, adjusted for Demand-Side-Management (DSM) programs. There are three classes of such programs. The first, which involves direct load control, such as industrial interruptible load and air-conditioner cycling, is called Class 1 DSM. The Class 1 set of DSM programs are oriented towards reducing peak demand but generally do not involve a change in the total amount of generation required. In other words, these programs provide the equivalent of spinning reserve capacity at peak times, without providing any generation. Efficiency programs that actually reduce electricity consumption, but may not reduce peak demand are categorized as Class 2 DSM programs. Coincidentally, many of these programs also lead to reduced demand, including reduced peak demand. Efficient lighting and air-conditioning are examples of Class 2 DSM programs that yield both energy and demand reductions. Class 3 DSM programs, which are considered "non-firm" in contrast to Class 1 and Class 2 programs, include response to prices, rate structure, and other initiatives taken by consumers, for instance, in response to new information. Class 3 programs are not included in this study.

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[44] All generation numbers are at the power plant and hence include transmission and distribution losses. 2010 numbers are as estimated by PacifiCorp.

[45] EIA 2010a

[46] Average for the 2010 to 2035 period calculated from EIA's assumptions for an economic growth rate of 3 percent from 2010 to 2020 and 2.5 percent from 2020 to 2035. See EIA 2010b.

It should be noted that we do not assume that efficiency improvements will be mainly achieved by utility investments and efforts. Rather, utility efforts, such as rebates for efficient refrigerators or air-conditioners, would supplement other policies, especially standards for buildings and appliances, which would achieve the bulk of the results.

PacifiCorp's current plans up to and including the year 2019 have been taken into account. The March 2010 IRP update also provides the annual reductions achieved in the load in each year, increasing from 369,380 MWh in 2010 to 1,820,160 MWh in 2019.[47] The increment of 1,450,780 over nine years averages to about 161,198 MWh per year or about 0.58 percent annual reduction relative to the BAU average load in the 2010-2019 period. This rate of efficiency improvement is assumed to continue after 2019 in the efficiency case. The same approach is taken for demand. This medium level of efficiency improvement is applied to the Nuclear/CCS supply scenario, where new generation is low CO_2 but not renewable. This is because both nuclear and coal with carbon storage will require large total investments in contrast to most renewable energy investments which can be made more modular. Hence, the focus of the electricity sector would tend to be on the generation side, though some efficiency efforts would be made since cost of generation would increase.

3. High efficiency projection

We constructed a "high efficiency" projection using the Demand-Side-Management scenario as the starting point. This scenario implies strong policy initiatives in both the commercial and residential building sectors for new buildings. However, they do not include the most ambitious goals that are already reflected in advanced current practices, such as passive building design. Overall, electricity generation in this high efficiency projection would be only about 12 percent lower than in the modest DSM case described above, which represents a continuation of the types of efforts described by PacifiCorp in its 2010 IRP update (and the 2008 IRP).

As noted in Chapter II, passive buildings that reduce the energy footprint by 70 percent or more can be built at reasonable cost but there is scant experience and data in the United States.[48] However, data do indicate that this would be a desirable goal, though it is not assumed in any scenario in this study. According to the American Physical Society 2008 report:[49]

> An experimental program run by Pacific Gas and Electric (PG&E) in the 1990s showed that 55–65% energy reduction could be accomplished using an integrated design approach [Brohard *et al.* 1997]. But the process was time-consuming and hard to replicate. The six low-energy LEED buildings offer further proof that 70% reduction in energy use can be accomplished. The challenge is to develop easily-replicable design and construction processes that achieve such results cost-effectively.
>
> Although it is a crucial component of the solution, integrated design cannot guarantee low energy commercial building performance. Even the best-designed buildings, with well-thought-out integrated systems, can suffer in their construction by contractors who

[47] PacifiCorp IRP 2010 pp. 67-68
[48] Zeller 2010
[49] APS 2008 pp. 62-63

lack the skills and experience to implement the details faithfully. And facility managers may not know how to operate a new system properly. A $100 home appliance comes with a setup and operating manual; many buildings do not.

In 2005, the American Institute of Architects' set a goal of zero net energy buildings by 2030. The goal included an immediate 50 percent reduction in the fossil fuel use in buildings (in 2005), with additional 10 percent improvement every five years, reaching carbon neutrality by 2030.[50] A similar goal has also been adopted by the U.S. Conference of Mayors.[51] The following description of the schedule is provided by Architecture 2030, the organization that initiated the 2030 Challenge program:

- All new buildings, developments and major renovations shall be designed to meet a fossil fuel, GHG-emitting, energy consumption performance standard of 60% of the regional (or country) average for that building type [by 2010].
- At a minimum, an equal amount of existing building area shall be renovated annually to meet a fossil fuel, GHG-emitting, energy consumption performance standard of 60% of the regional (or country) average for that building type.
- The fossil fuel reduction standard for all new buildings and major renovations shall be increased to:
  - 70% in 2015
  - 80% in 2020
  - 90% in 2025
  - Carbon-neutral in 2030 (using no fossil fuel GHG emitting energy to operate).

  These targets may be accomplished by implementing innovative sustainable design strategies, generating on-site renewable power and/or purchasing (20% maximum) renewable energy."[52]

Of course not all of this reduction is in electricity requirements or efficiency; other fuels are involved and electricity can be generated on site. Further, achieving truly zero net energy buildings in the commercial sector for all types of buildings will require substantial research, development, and demonstration efforts, in addition to standards. Hence, in this study a much less ambitious goal is adopted for the 2013 to 2050 period, to be accomplished by efficiency improvements in the electricity portion of building sector.

The efficiency improvements envisioned here are far more modest and could be achieved through appliances standards and building standards that correspond to available technology, as well as by retrofitting existing buildings. Further, reduction efficiency can be increased by certain replacements of purchased electricity with other fuels, for instance, through installation of combined heat and power systems and absorption air conditioning systems.

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[50] AIA 2010

[51] References for building efficiency and zero net carbon goals adopted by the American Institute of Architects and other bodies can be found at The 2030 Challenge at http://architecture2030.org/2030_challenge/the_2030_challenge and http://architecture2030.org/2030_challenge/adopters. (Architecture 2030)

[52] Architecture 2030

The Department of Energy's buildings program indicates that significant reductions in energy use in new buildings relative to typical new buildings can be made at little or no increased cost:[53]

> The U.S. Department of Energy's Building America program directly addresses the fundamental problems of bringing energy efficiency to new residential buildings. The program provides technical support for builders to construct very energy-efficient residential buildings at low or no increased first cost to the consumer. Building America works with builders who are responsible for more than 50 percent of new residential construction in the United States. More than 50,000 competitively priced houses have been constructed under the program, with an average energy use for heating and cooling that is 30 to 40 percent less than that of typical new residences.

Standards for appliances and buildings are, in our opinion, the most efficient means for achieving efficiency. This has already been shown in specific cases, with refrigerators being the most dramatic example. It should be pointed out that standards may not always be a suitable means to achieve efficiency and this is likely the case with heavy industry, for instance. These industries are used to watching out for their energy bills and respond to price signals. However, some equipment such as small motors used widely in industry may suitably be improved through a standard setting process. Standards are efficient when there is competition in the field, as among appliance makers or builders. Also, standards are the best way to overcome the so-called split incentive in buildings, whereby builders and landlords have little incentive to invest in efficiency even when it is economical because they don't pay the utility bills. Figure IV-3 shows the cost of efficiency measures for appliances in the form of a supply curve—that is, it shows the amount of efficiency that can be achieved in specific parts of the residential electricity sector at a particular price in cents per kWh.

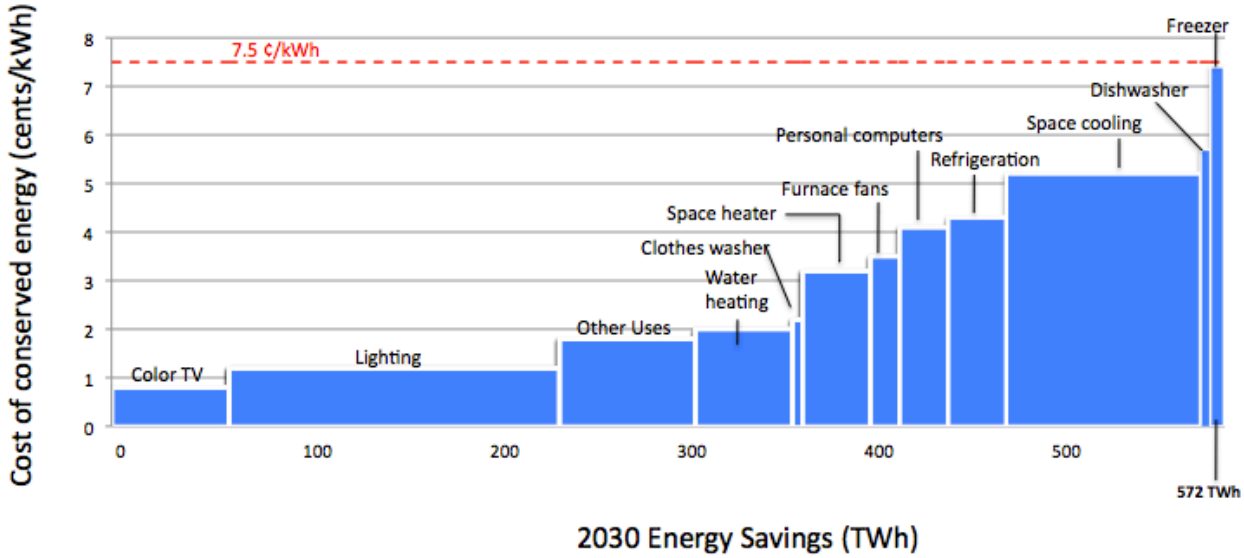

Figure IV-3: Supply curve for residential electricity efficiency improvements by 2030 with the Utah residential rate. Source: APS 2008 Figure 25 (p. 76), adapted to show the lowest Utah PacifiCorp residential electricity rate in place of the national residential rate

[53] APS 2008 p. 63

For instance, standards for efficiency of color TVs would save about 60 million MWh (60 TWh) nationally at a cost of about 0.8 cents per kWh. Moreover, once the standards are mandated, it is the consumer of the TV who pays for the extra cost of the TV and reaps the benefits in terms of much lower electricity bills. Similarly, the national efficiency potential for residential lighting is huge—170 million MWh (170 TWh), at a cost of about 1.2 cents per kWh.

Table IV-1 shows the data in Figure IV-3 in detail; this enables a calculation of an average cost over all measures. The maximum price up to which calculations are done is 7.5 cents per kWh, which is the lowest cost for PacifiCorp residential electricity in Utah. The amounts of electricity saved for each end use correspond to national data. However, almost all of the savings other than furnace fans and space cooling are independent of the weather, the supply curve applies broadly.

Table IV-1: Efficiency supply curve

Item	Savings, TWh	cost cents/kWh	Total cost, million $
TV	60	0.8	480
Lighting	170	1.2	2,040
Other	70	1.8	1,260
Water heating	50	2	1,000
Clothes washer	5	2.2	110
Space heater	35	3.2	1,120
Furnace fans	15	3.5	525
Personal computers	25	4.1	1,025
Refrigerators	30	4.3	1,290
Space cooling	100	5.2	5,200
Dishwasher	5	5.7	285
Freezer	7	7.4	518
Totals (average per kWh)	**572**	**2.60**	**$14,853**

Note: Values in the savings and cost per kWh columns were read off from the efficiency supply curve shown in Figure IV-3 and are therefore approximate. Source: based on APS 2008—see Figure IV-3 above. Note that the "refrigerators" item in this table is under the more general rubric of "refrigeration" in Figure IV-3.

Table IV-1 shows that the average cost of all measures is 2.6 cents per kWh or $26 per MWh. This is much less than the lowest cost of residential electricity in Utah of $75 per MWh. The total reduction in electricity use by adoption of all these measures would be 30 percent of residential electricity consumption in 2030. While building and appliance standards would be the central policy tool to achieve the low average level of costs, more thorough implementation of the measures can be achieved by supplementing them with utility incentive programs. For instance, refrigerators are rather durable appliance that can last for decades. But refrigerators that are 25 or more years old consume three times or more the electricity of new ones.

Since the cost of residential electricity in Utah is about equal to the highest cost item showed in Table IV-1, the estimate in the 2008 American Physical Society study can be applied: about 30 percent of

residential electricity use can be eliminated through economic efficiency measures by 2030.[54] If the changes are brought about mainly by building and appliance standards, the costs are primarily borne directly by consumers via the prices of buildings or appliances (though as we see below prices do not always rise in response to regulations requiring higher efficiency). Hence the above cost table is not a cost table reflecting utility efficiency program costs but the costs of actually purchasing higher efficiency lighting, televisions, refrigerators, air-conditioners, etc. However, the effectiveness and reach of appliance standards can be increased, especially in the case of improvements in existing buildings and accelerated replacement of appliances, by utility rebate and education programs. We therefore add 0.4 cents per kWh (or about 15 percent) to the cost of 2.6 cents per kWh to 3 cents per kWh (or $30 per MWh) to reflect supplemental incentive and overhead costs.

The importance of the issue of standards for appliances is illustrated in Figure IV-4, which shows the history of three household appliances—refrigerators, central air-conditioners, and gas furnaces. Refrigerator standards reinforced market-based trends that were occurring in the first part of the 1970s; the combination resulted in efficiency improvements by a factor of four in about 30 years. Smaller but also significant improvements also occurred in the other two cases.

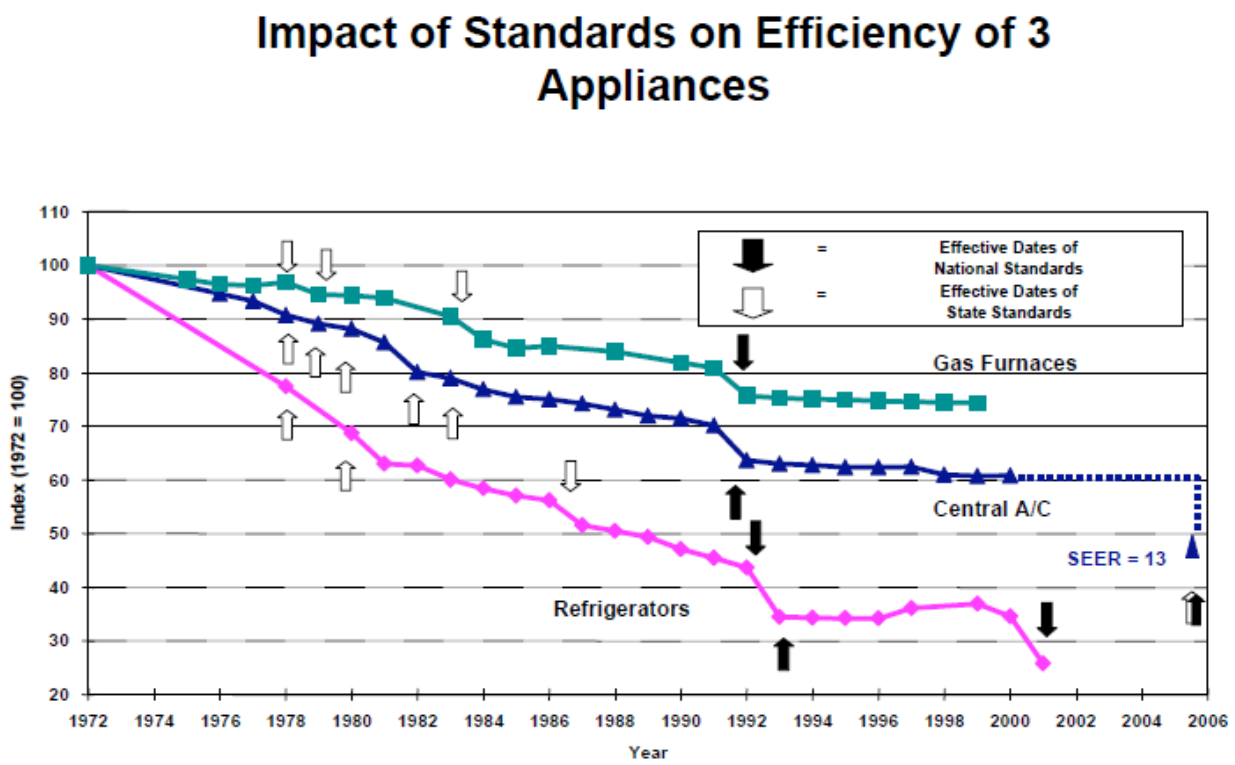

Figure IV-4: Three examples of the effect of appliance standards over time. Source: Rosenfeld 2008.

Figure IV-5 shows the history of refrigerator standards, sizes, efficiency, and prices in detail. Even as efficiency has improved by a factor of four and the size has increased by about one-fourth, the average price (in constant dollars) fell by almost a factor of 3 since the early 1970s.

[54] APS 2008 p. 76

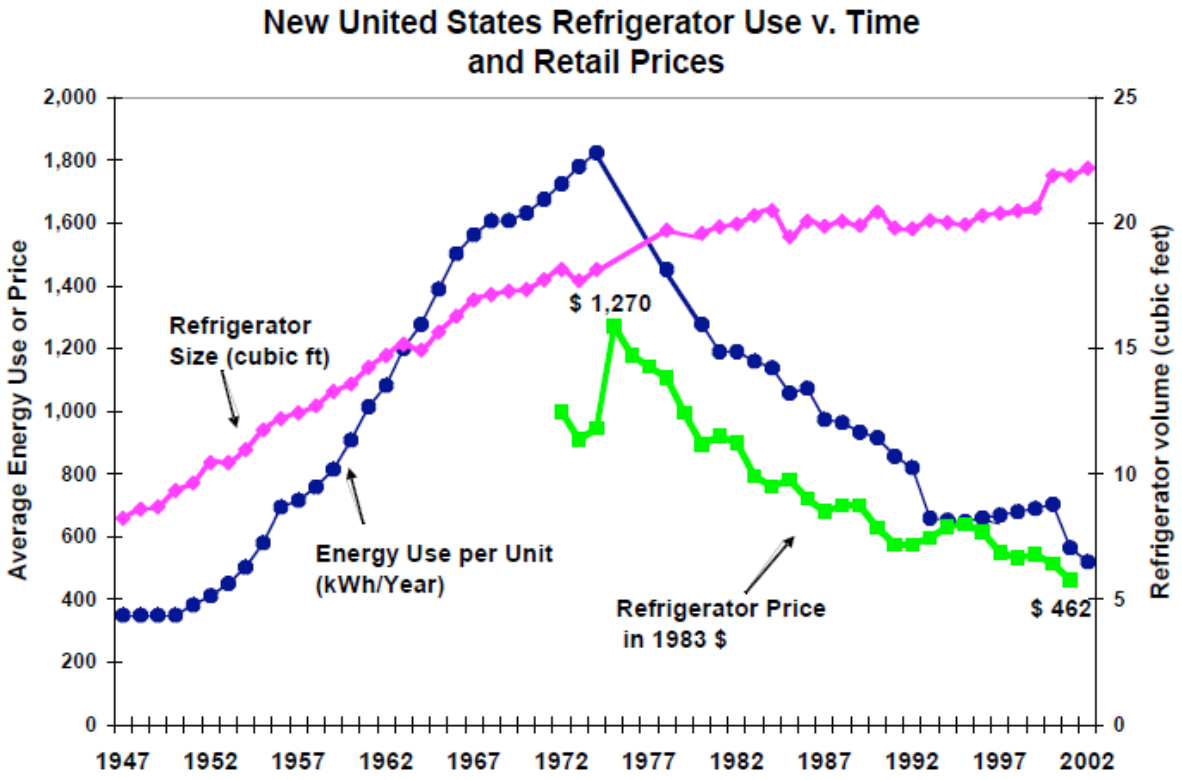

Figure IV-5: Refrigerator efficiency, size, and prices over time. Source: Rosenfeld 2008.

The 2008 American Physical Society report on energy efficiency cited the following reasons in support of the need for standards for appliances and buildings:[55]

> Minimum-efficiency standards are needed to overcome market failures that restrict the use of more efficient products. Among these failures are:
> • Third-party decision makers (e.g., landlords and builders) who purchase appliances but do not pay the operating costs of the products they purchase;
> • Panic purchases that leave little time for consumers to become educated;
> • Inadequate and misleading information about the relative energy performance of products; and
> • High first costs for efficient equipment due to small production quantities and the fact that manufacturers frequently combine efficiency features with extra non-energy features in expensive trade-up models.

As a final example, Figure IV-6 shows the effect of increasing house size on central air-conditioning electricity use with no efficiency changes, with higher efficiency air-conditioners, and with both high efficiency A/C and building standards. When both appliance and building standards are included, new building air-conditioning electricity requirements can be reduced by 60 percent relative to today and by 70 percent relative to the new, larger construction without efficiency standards.

[55] APS 2008 p. 77-78

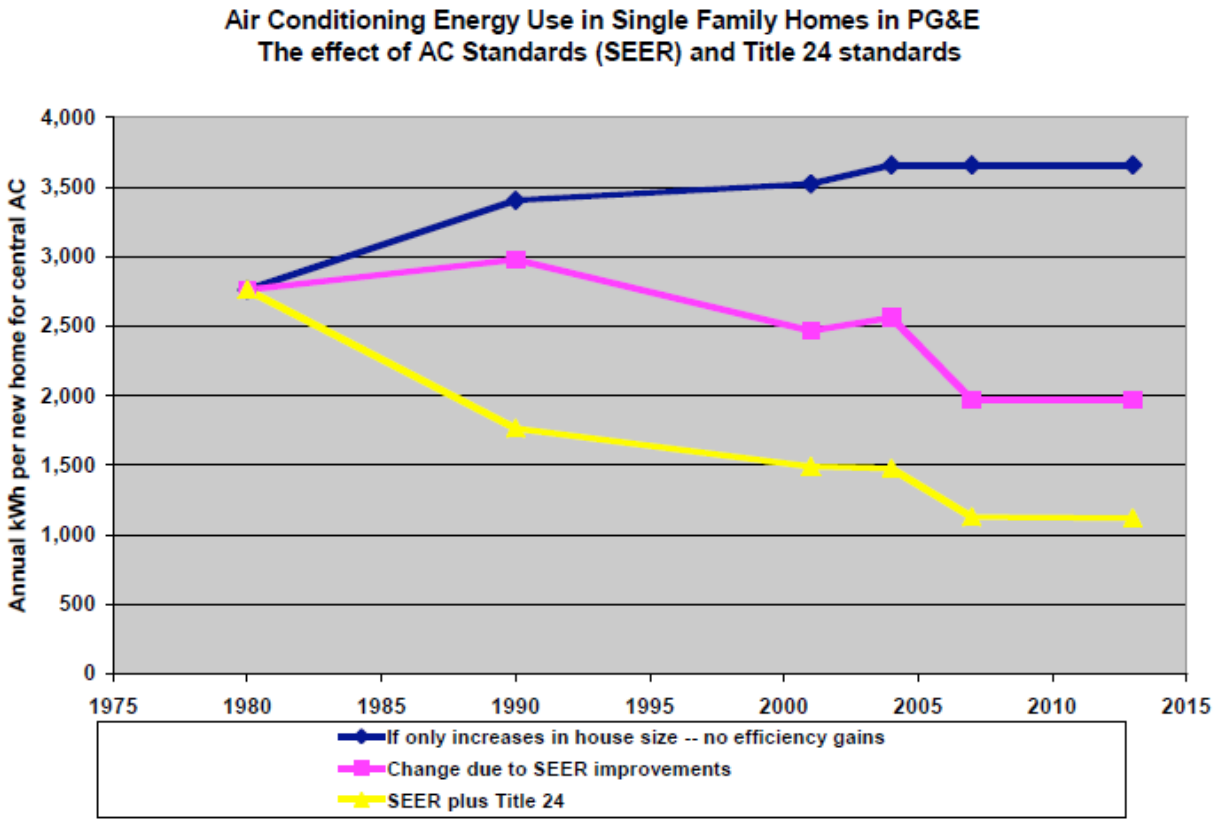

Figure IV-6: Central Air-conditioning energy use in a new single family home—effect of building size, efficient air-conditioning and building standards in California. "Title 24" specifies California's building standards. "SEER" stands for "Seasonal Energy Efficiency Ratio," an efficiency rating. Source: Rosenfeld 2008. See also California Building Standards 2009.

It should also be possible to achieve significant efficiency improvements in existing buildings. Measurements of retrofits in low-income housing in Florida, for instance, showed payback times of one to less than four years for most measures. [56] Measurements, though scarce, indicate a similar result in commercial building retrofits:[57]

> In determining what efficiency gains are possible with current and emerging technologies, it is useful to start by looking at what is happening under current standard practices. Contractors focused on energy upgrades to existing residential buildings achieve energy efficiency improvements ranging from 15 to 35 percent by installing better and more efficient insulation, windows (in some instances) and lights; by eliminating infiltration and duct leakage; by upgrading furnaces, boilers and air conditioners; by replacing the power supplies that waste electricity when their devices are in standby or low-power mode; and by replacing old appliances with newer, more efficient ones.

[56] Makhijani 2010a p. 81
[57] APS 2008 p. 60

Energy service companies (ESCOs) regularly work with larger commercial customers to perform energy audits followed by upgrades in lighting, HVAC equipment and system controls, by which they achieve cost-effective energy savings**.** We were unable to locate performance data for U.S. ESCOs. In Berlin, Germany, however, ESCOs have improved the energy efficiency of 1,400 buildings by an average of 24 percent at no cost to building owners and a profit to the ESCO that paid for the upgrade [C40 Cities, 2008]. U.S. results are likely to be similar. Generally, it is easier to achieve efficiency gains in new buildings than in existing ones.

The high efficiency projection assumes that new buildings from 2013 onwards will have a purchased electricity footprint that is 50 per cent of the electricity footprint of the average of existing residential and commercial building stock in 2007. This is broadly comparable to the building code adopted by University of Utah in 2010, which mandates a 40 percent reduction in energy use in new buildings (except hospitals) compared to the standard code.[58] The high efficiency demand scenario is applied to the supply scenarios that have high penetration of renewables.

Figure IV-7 shows the load projected for the three demand scenarios, in megawatt-hours per year; Figure IV-8 shows the demand in megawatts. The load projections are for generation and include transmission and distribution losses. The demand projections do not include a reserve margin, which is considered separately and included in the supply chapter calculations. The reserve margin adopted is 12 percent.

[58] University of Utah 2010 Section 1.2.2 and LEED 2010 p. 35. The LEED score of 15 points, required in the Utah standards corresponds to a 40 percent reduction in energy cost. The authors appreciate Myron Willson's assistance regarding the University's standards.

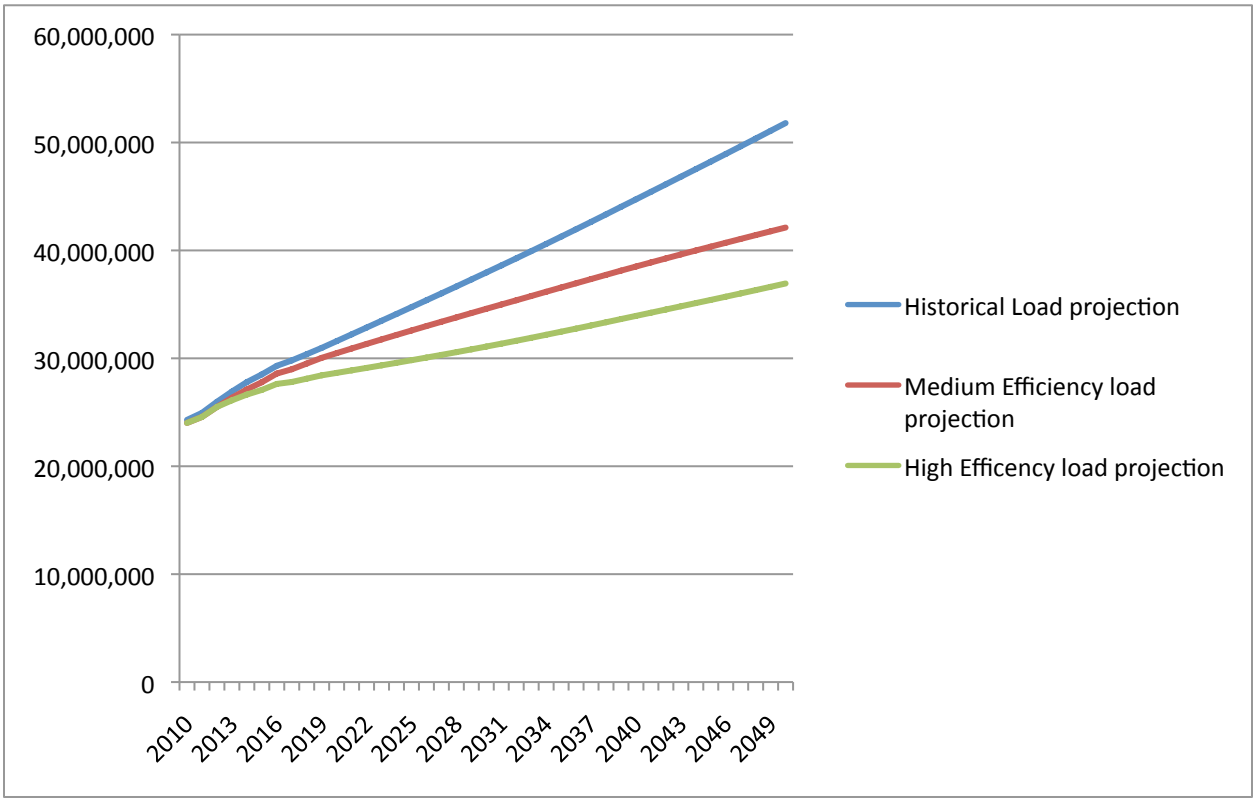

Figure IV-7: Load projected for the three demand projections in the eUtah study, MWh/year

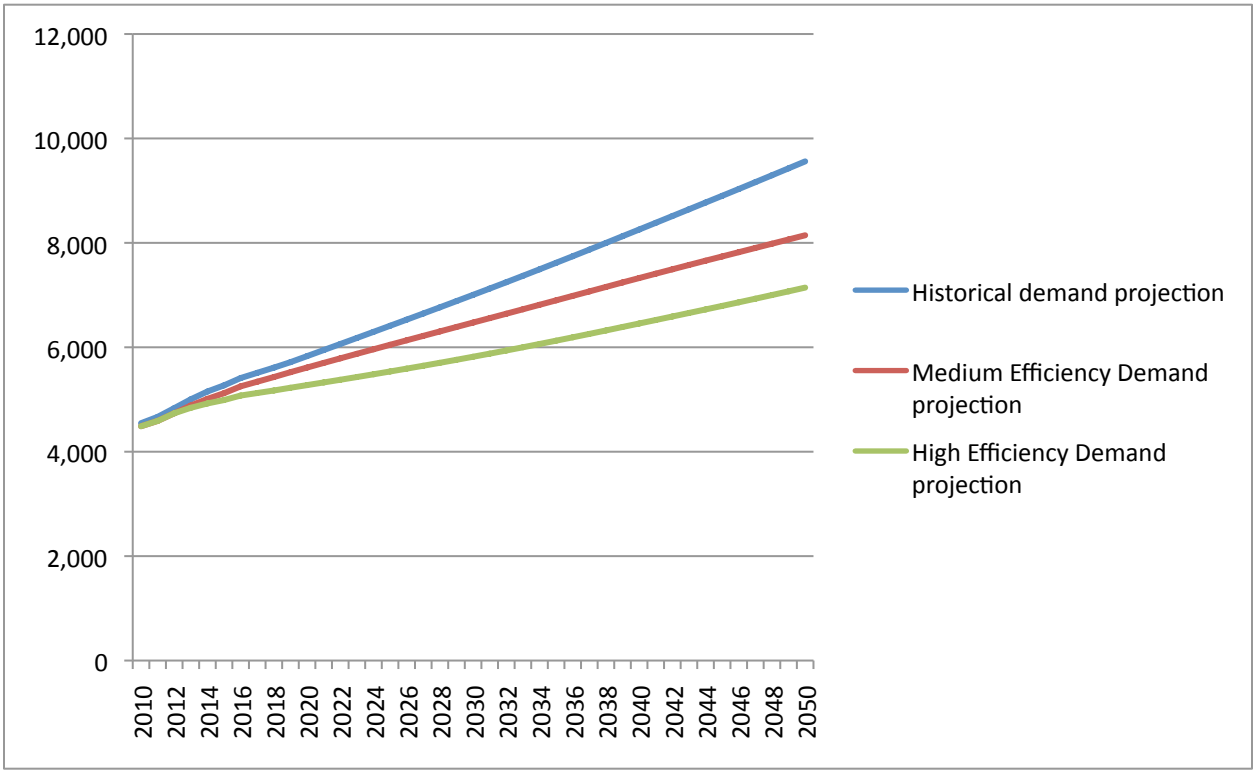

Figure IV-8: Peak demand projections for the eUtah study, MW.

V. Joining Supply to Demand

A. Introduction to supply scenarios

We have created five supply scenarios around three concepts—a scenario that assumes zero carbon price and continued use of coal without CO_2 restraints, a conventional thermal generation system scenario (nuclear, coal, natural gas) but with low carbon emissions, and three scenarios in which renewables (solar, wind, geothermal) play a major role, with carbon reduction of 70 percent to about 95 percent relative to 2010 emissions. Due to modeling, data, time, and financial constraints, all scenarios are oriented to central station generation. This limitation of the study results in non-optimized renewable energy scenarios as is explained in Chapter VI.

None of the scenarios are offered as roadmaps for a future of Utah's electricity sector. Rather they are options set up to compare risks of different approaches as clearly as possible. This could enable investment decisions in a direction that would lower risk and increase flexibility and choice, while providing electricity at a reasonable cost with low environmental impact. Equally important, the analysis allows for the identification of gaps in research and demonstration efforts. These efforts, if made, could allow Utah to make the best use of its ample renewable resources and also to become a leader in energy technologies, including storage, integration of distributed generation and storage technologies, and carbon capture and storage, notably with natural gas.

The approach to the design of the scenarios in this study is in keeping with the suggestions of the Advisory Board that a fully renewable electricity system should be evaluated and compared to more conventional alternatives through a variety of different perspectives such as costs, risks, CO_2 reductions, and water use. As noted in Chapters I and VI, there are a numbers of ways in which costs potentially could be reduced compared to the centralized approach that relies only on Utah renewable resources. Attachment B provides the main technical and economic assumptions and parameters used in this study.

In all cases, a peak margin of 12 percent is maintained throughout the year, reflecting industry standard reliability requirements. Further, from 2020 onwards we have assumed that all generation resources required will be built in Utah. This is largely the case already, but not entirely. PacifiCorp purchases and sells electricity to other utilities and also net transfers power from the western to the eastern sector. The transfers are assumed as planned by PacifiCorp until 2020. No sales and purchases are included. It is assumed that the modest deficits that occur in some years prior to 2020 will be covered by purchases. After 2020, all generation and consumption is assumed to be within Utah's PacifiCorp area. We also assume that its relative share of about 80 percent of Utah supply will remain unchanged.

These assumptions mean that the scenarios are not typical IRP scenarios, as already stated. Rather they allow a clear view of the effect of major directions in investments. No assumption is made about CO_2 costs. Rather, different levels of CO_2 reduction are adopted for the scenarios. The price of CO_2 implicit in the generation choices can be calculated. This allows a policy choice as to the level of CO_2reduction to be sought and a comparison of costs and options for achieving it. Given different unit sizes and lead times for generation technologies, this approach also allows for the estimation of the amount of capital at risk at any time. However, we have not used the current commercial unit sizes for nuclear reactors because doing so would make the construction of a scenario that supplies only Utah rather impractical

and leave large capacity surpluses for considerable periods. Alternatively, there would have to be substantial sales out of state.

Some details as to the construction of the supply scenarios are as follows:

1. Presently, the PacifiCorp generation system in Utah is a part of the eastern section of its operations. The existing portion of PacifiCorp is proportional to the ratio of the peak load in Utah to that in the eastern section of PacifiCorp; this is just over 75 percent. Specifically, about 125 MW of the existing 156 MW of existing hydro and geothermal is assigned to Utah in this way and included in the existing portfolio through 2050.
2. PacifiCorp has a number of fossil fuel plants (coal, natural gas) that were installed at various times in between the 1950s and the decade of the 2000s. The retirement of these existing plants was done according to the age of the plant, according to the scenario. In the Business-as-Usual scenario, existing fossil fuel plants are retired at sixty years. In all the other cases, they are retired at 40 years. Existing capacity in 2050 in all but the BAU scenario reflects remaining Demand-Side-Management Class 1 capacity as of 2012, interruptible capacity escalated from 2020 onwards includes the rate of demand growth, and the portion of existing eastern hydro allocated to Utah (as explained above).
3. PacifiCorp, like other utilities, engages in both sales and purchases of electricity. The supply and demand scenarios in this study exclude all such transactions. We assume that any gaps in the 2010 to 2019 period will be met by purchases. After 2020, all generation requirements for Utah in all scenarios are met from facilities in Utah.
4. A 12 percent reserve margin is maintained throughout the year in all scenarios. This allows all scenarios to be comparable in terms of reliability of supply.
5. Additions to capacity planned by PacifiCorp in the March 2010 IRP update for the 2010-2020 period are maintained in all scenarios. About 75 percent of the planned eastern section additions are allocated to the PacifiCorp's Utah service area.

Figure V-1 shows how existing capacity is retired in all scenarios other than the BAU scenario. As noted above, existing plants are retired after 40 years. Small coal plants dating from the 1950s are retired at 60 years in the 2010 to 2020 period. Note that only power plants located in Utah are retired for the purposes of this analysis. Existing DSM Class 1 capacity, achieved through measures such as air-conditioner cycling are maintained; interruptible capacity grows at the same rate as demand. We do not assume that loads will be interrupted in any scenario; the interruptible capacity is therefore not used to support renewable capacity increases. Rather, a 12 percent margin is sought to be maintained throughout the year.

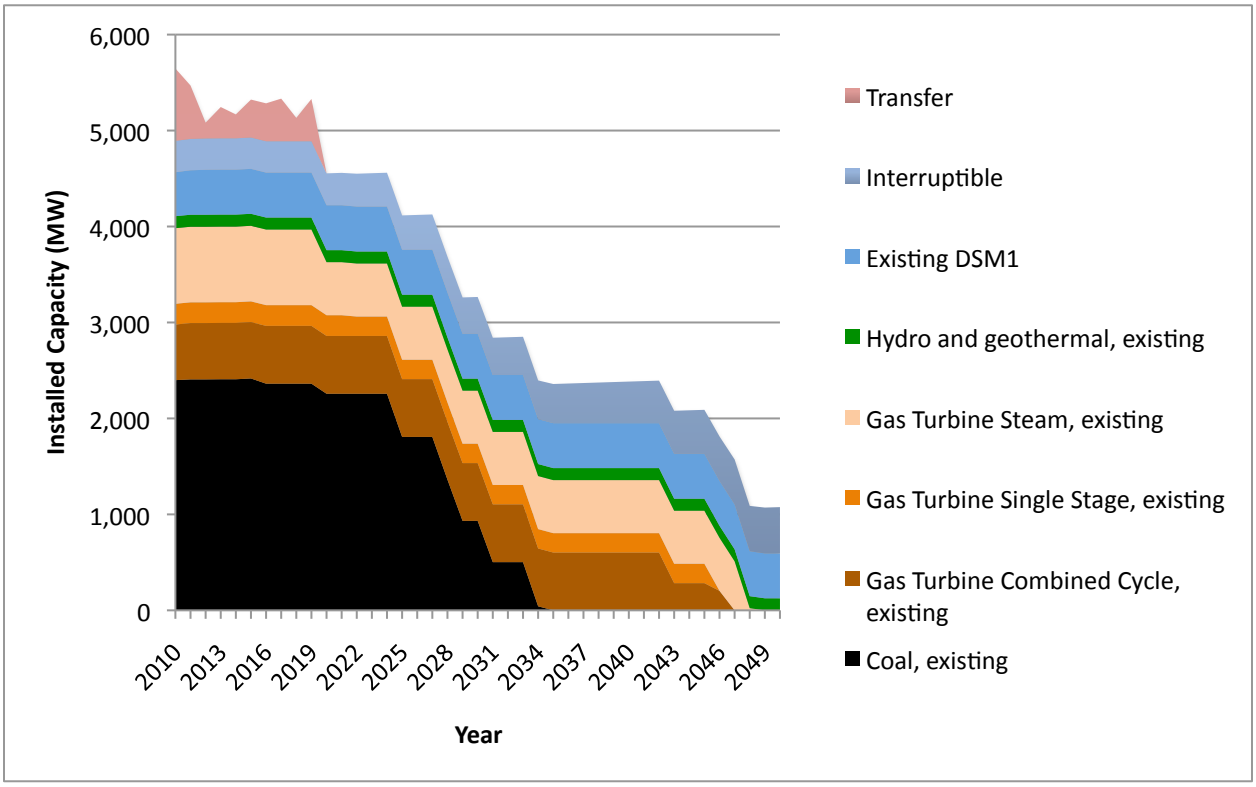

Figure V-1: Existing capacity retirements assumed for all scenarios except the BAU scenario. In the BAU scenario, existing capacity is retired after 60 years rather than 40 years.

B. Supply scenarios

The five supply scenarios developed in this study are:

1. **Business-as-Usual (BAU)**: This is a reference scenario that assumes the continued dominance of coal in the supply system. Coal-fired power plants are generally replaced by coal-fired power plants. Existing plants are retired at 60 years. No new efficiency or DSM measures are assumed. In this case, electricity generation grows to about 52 million MWh by 2050, as discussed in Chapter IV. We again emphasize that this does not represent an actual business as usual approach in the sense that planning would proceed as it has in the past. Moreover, it is not at all clear whether PacifiCorp will retire existing plants after 60 years or whether retirement will occur earlier or later. A coal-to-coal scenario is useful because it allows us to compare the cost of the various low-carbon approaches to a continued high-carbon emissions electricity sector. It also allows a calculation of the cost of limiting carbon emissions using different approaches. Finally it allows an estimation of the financial risk that various levels of carbon prices, in the event such constraints are applied, may have on a coal-oriented system.
2. **A low-CO_2 scenario with nuclear and coal with carbon capture and storage (Nuclear/CCS)**: This scenario provides an example of a conventional approach to CO_2 reduction and assumes that the structure of the present electricity sector, which is dominated by thermal plants, will continue, but with carbon reductions as an added goal. Natural gas plays a supporting role to coal with CCS and nuclear power, both in the form of combined cycle plants and single-stage gas

turbines. The scenario results in approximately 70 percent CO_2 emissions reductions relative to emissions in 2010 and 80 percent relative to the emissions in 2050 in the BAU scenario. A medium level of efficiency improvements, extending present PacifiCorp plans for DSM Class 2 efficiency measures, is used with this scenario. Demand rises to about 42 million MWh by the year 2050 in this scenario.

3. **Renewables with natural gas (Renewables/Natural Gas)**: In this scenario, CO_2 reductions comparable to the nuclear/CCS scenario are achieved by using solar wind and geothermal generation, supplemented by a significant amount of combined cycle power plants fueled by natural gas. The high efficiency demand scenario is used here. Demand rises to about 37 million MWh by the year 2050 in this scenario.
4. **Renewables with natural gas and carbon capture and storage (Renewables/Natural Gas/CCS)**: This is the same as the Renewables/Natural Gas scenario, except that carbon capture and storage has been added to natural gas combined cycle power plants in order to achieved CO_2 emissions reductions of 93 percent relative to 2010 by the year 2050. The high efficiency demand scenario is used here. Demand rises to about 37 million MWh by the year 2050 in this scenario.
5. **eUtah scenario**: This scenario relies almost totally on renewable energy—wind, solar, and geothermal—by 2050. Natural gas is used minimally to support generation from compressed air energy storage, resulting in an electric system with overall CO_2 reductions of 97 percent relative to BAU and about 95 percent relative to 2010. The high efficiency demand scenario is used here. Demand rises to about 37 million MWh by the year 2050 in this scenario.

1. **Business-as-Usual Scenario (BAU)**

As noted above, the BAU scenario assumes that there would be no carbon restraints and no pollution restraints on existing plants that would impose extraordinary costs. Existing plants would be retired at sixty years. Wind generation capacity planned by PacifiCorp until 2020 is maintained without further additions after 2020. A small amount of geothermal capacity is included. Peak demand plus the 12 percent reserve margin rises to almost 9,600 MW by 2050. The basic approach is to design a scenario in which coal is supplemented by natural gas, much as it is in the present supply system in Utah. This creates a reference scenario that results in the lowest case levelized costs in the absence of resource, fuel cost, pollution, or technology imperatives (such as new technologies cheaper than new coal). Evidently, the carbon-restraint-related risk is the greatest in this scenario. Wind capacity's contribution to the supply is counted as 10 percent of installed capacity in computing capacity requirements. The result is shown in Figure V-2. When comparing the existing capacity to the other scenarios, it should be noted that existing capacity is retired after 60 years in the BAU scenario (since there are no carbon constraints). This means that the capacity installed after 1990 would still be in operation in 2050.

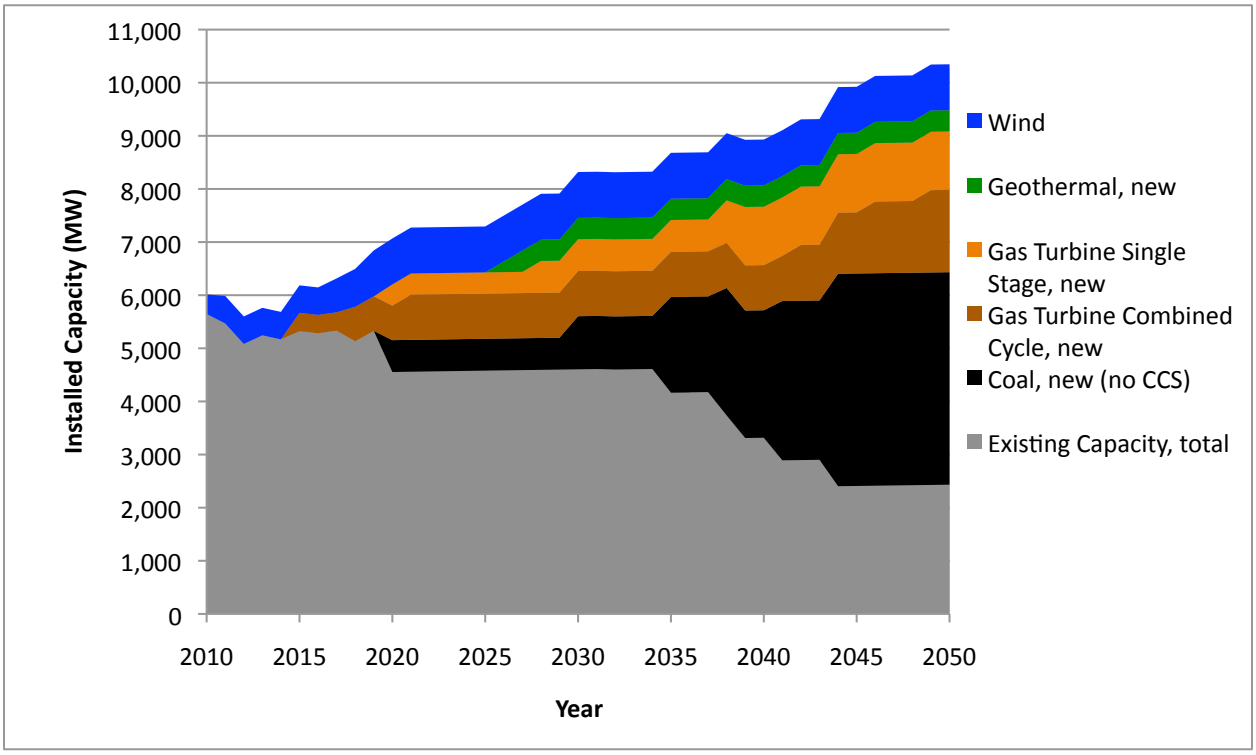

Figure V-2: Installed capacity (MW) in the BAU (Business-as-Usual Scenario), 2010 to 2050.

Figure V-3 shows the facility retirement pattern assumed for the BAU scenario.

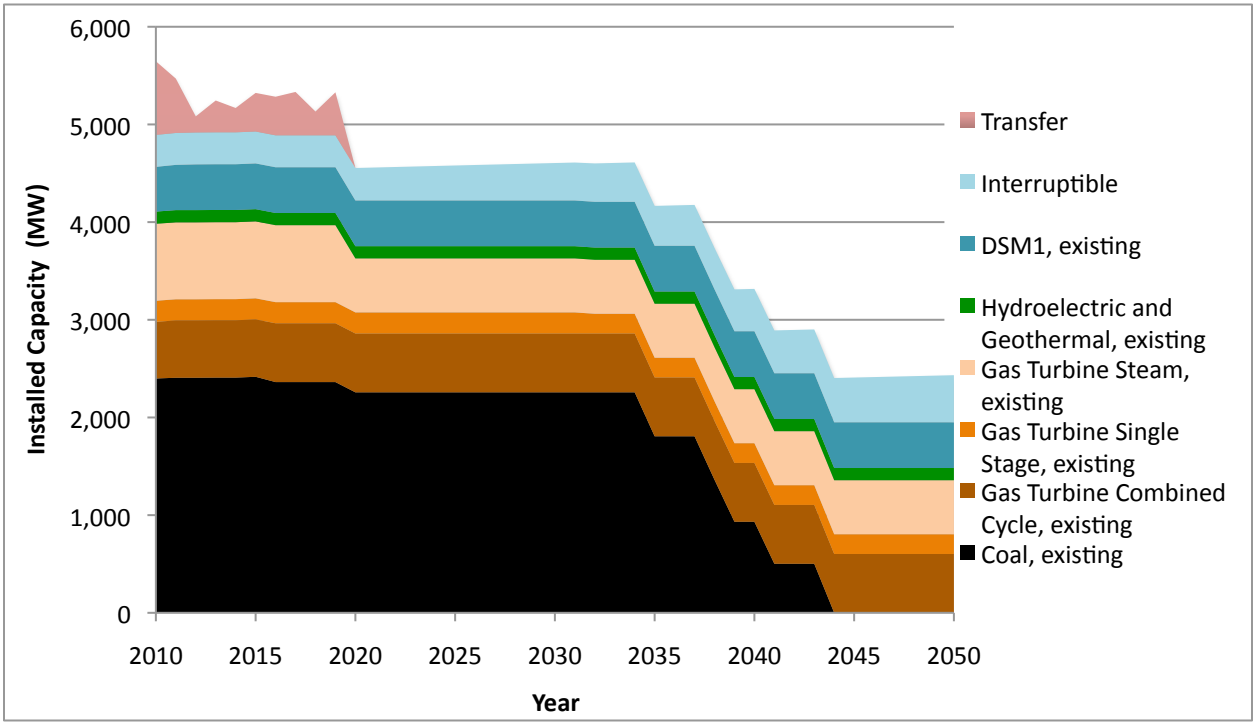

Figure V-3: Retirement of existing capacity in the BAU scenario.

It should be reiterated that this retirement schedule is not based on PacifiCorp projections. The schedule of actual retirements will not only depend on carbon policy and cost, but also on other expenses that might be incurred in keeping existing plants open, notably coal plants. For instance, if extensive and costly retrofits to existing facilities are required, retirements may occur earlier than indicated; if not retirements may occur later. The 60-year schedule used here simply reflects one possibility in the absence of carbon constraints and allows for a comparison of the BAU scenario on a realistic basis with the four carbon-constrained scenarios.

2. **The Nuclear/CCS scenario**.

This scenario assumes that most CO_2 emissions will be eliminated (about 80 percent reduction relative to the BAU scenario in 2050, which is about 70 percent reduction relative to CO_2 emissions in the year 2010) by the use of nuclear power and coal with carbon capture and storage (CCS). We assume that half of the combined central station nuclear and coal with CCS capacity does not differentiate between new coal with CCS capacity and new nuclear capacity. Their costs are about the same as presently estimated (see Chapter VI), so the exact mix does not make a difference in the overall generation cost. That said, we also note that the levelized costs of CCS are more uncertain than nuclear costs, since the technology is not yet commercially established. The amount of CO_2 emissions does depend on the mix of coal with CCS and nuclear, since nuclear has no CO_2 emissions at the power plant while coal with CCS does not result in a full elimination of CO_2 emissions. We have assumed that coal with CCS would have about 20 percent of the CO_2 emissions compared to a plant with no CCS. This assumption captures the effect of both the reduced efficiency as well as the fact that the economics of CCS will require something less than complete CO_2 capture (80 percent is assumed in this study). There is considerable uncertainty in both nuclear and CCS costs for different reasons. For simplicity we have assumed a 50-50 mix (except for some financial calculations in Chapter VII to compare to nuclear to renewables). The smallest baseload nuclear or coal unit size added in this scenario is 300 MW.

As noted, this scenario maintains the centrality of thermal generation in the Utah electricity sector. In this scenario, combined cycle natural gas power plants are assumed to operate as intermediate load plants at 35 percent capacity factor. Single-stage gas turbines are also employed, at 5 percent capacity factor. No renewables are added beyond the wind capacity that already exists and is planned by PacifiCorp for the 2010-2020 period. Wind capacity's contribution to the supply is counted as 10 percent of installed capacity. The result is shown in the Figure V-4 below.

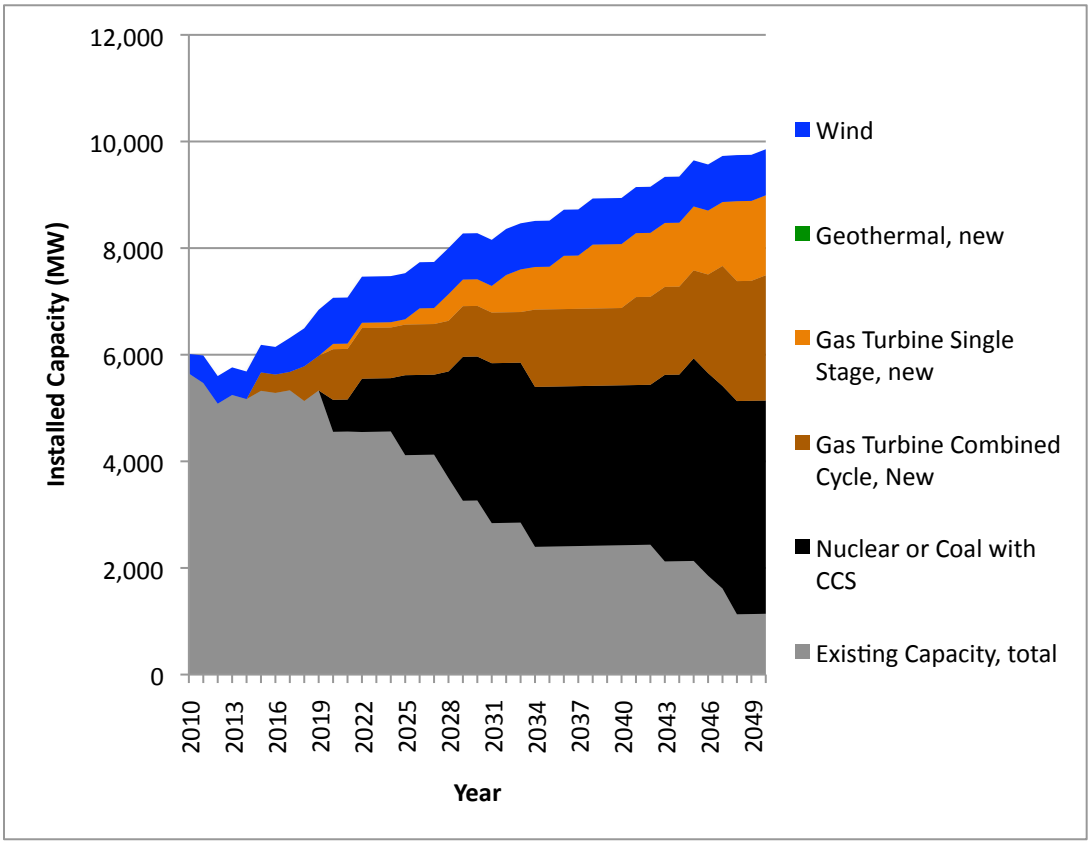

Figure V-4: Installed capacity (MW) in the Nuclear/CCS scenario, 2010 to 2050

Introduction to the renewable supply scenarios

There are a number of elements that are common to the three renewable energy scenarios, as described in this section. We have already covered the choice of solar and wind locations in Chapter III. Here we focus on a few other elements.

- **Renewable resource types**: Only three renewable resources are used in these scenarios: geothermal (in a baseload mode, with 85 percent capacity factor), concentrating solar power, and wind.
- **Central station plants**: All resources are assumed to be central station plants. However, the unit additions to capacity can be as low as 100 MW at a time, though in many years more capacity than this is added.
- **Storage technology**: We assume a single storage technology: compressed air energy storage, which is described in more detail below. Suffice it to note here that this is a commercial technology that has been used for peak shaving in the context of coal and natural gas fueled systems (in Germany and the United States). The approach here is to combine storage, wind, solar, geothermal (and in two scenarios, combined cycle natural gas plants) to provide dispatchable electricity with the same reliability as the present system. Compressed air energy storage uses renewable energy when generation exceeds demand to compress air for storage. At times when demand is greater than renewable energy supply, compressed air is withdrawn

from storage and heated with natural gas. This hot compressed air drives a single-stage turbine, much like a peaking gas turbine power plant.

- **Location of storage**: We make no assumptions as to whether storage will be co-located with wind and/or solar facilities.
- **Single solar technology**: Only a single solar technology is assumed: dry concentrating solar thermal power plants. As a result, we have not included distributed solar generation in the renewable portfolios included in this report. However, intermediate scale solar PV as well as large scale solar PV are likely to be competitive with concentrating solar thermal power plants. In particular, if the Department of Energy's goal of central station solar PV at $1 per peak watt is achieved by the target date of 2017 or even anywhere close to that target date,[59] intermediate scale solar PV—from 1 to 20 MW per installation in urban areas—will be increasingly attractive. The same may also hold true of other distributed solar technologies, such as solar Stirling cycle systems,[60] or solar absorption heating and cooling systems.[61] In this context, it is evident that the choice of concentrating solar thermal power as the single technology for solar energy is a rather artificial and limiting constraint. This issue is further discussed in Chapter VI.
- **Spilled energy**: "Spilled energy" is renewable electricity that could be utilized at a particular time but is not because there is no corresponding load and no additional available storage capacity at that time. This problem arises because the combined wind/solar/storage capacity is geared to providing reliable supply with a 12 percent peak margin at all times. Capacity in such a situation is thus determined by the presence of extended times of low wind and solar energy availability, which may occur in the winter, rather than at peak air-conditioning and other late afternoon/early evening summer loads. This is the problem of relational system peak (rather than the conventional peak load created by simultaneous growth of demand at certain times), as already discussed. Using a single centralized storage system to meet the relational system peak creates large excess renewable capacity at other times, leading to the costly problem of a large amount of spilled energy. None of the renewable energy scenarios include elements such as generation driven loads, local storage systems, or utilization of spilled energy to make other fuels, such as hydrogen. Such use would require additional investments on the consumer's side of the grid, but would also reduce the renewable capacity (including storage) required for an electricity system in which most of the generation comes from solar and wind energy.

One of the most important features of a renewable electricity system in which solar and wind are the main supply is that the entire notion of peak load needs to be redefined. In the traditional—that is present-day—the peak load occurs at the time when consumers of electricity simultaneously have the largest combined load. The amount of generation responds to this load. Generation capacity that can be dispatched (i.e., changed with changes in demand) is installed to respond to anticipated loads. Some types of generation may take a day or longer to be brought on line (typically large baseload units like nuclear reactors), while others might respond in hours or minutes (hydropower units and single-stage gas turbines being examples of the last). Peak load is determined entirely by the highest simultaneous load that consumers put on the system.

It is different in a system in which solar, wind, and storage are the main sources of supply to the grid. As already discussed, systems with high solar and wind penetration will have a "relational system peak."

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[59] DOE ARPA-E 2010

[60] Brehm 2010. Stirling cycle solar power plants of just 3 kW each are being manufactured in Washington State by Infinia. The system can be installed in multi-megawatt arrays. See http://www.infiniacorp.com.

[61] See for instance http://www.climatewell.com.

This occurs when the combined generation supply (mainly renewable) is low AND the stored energy is low as well. In the case studied here, the relational system peak actually occurs in the winter, as we will see below. This is because solar energy generation is typically the lowest in the winter. During periods of low wind and solar supply, energy is drawn from storage. Prolonged withdrawal from storage with low renewable supply creates the relational system peak, which can occur even when demand is far below its annual peak load as conventionally defined. The implications of relational system peaks for economics and for electricity system design are further discussed below, in Chapter VI, and in the findings and recommendations in Chapter I.

All three scenarios that follow have renewable energy as the principal supply source and are collectively called "renewable energy scenarios" in this study. When a specific one is referred to, that is done by its specific name.

3. The Renewables/Natural Gas scenario

This scenario has four generation components: solar, wind, geothermal, and combined cycle natural gas plants. It also has compressed air energy storage equivalent to 34 hours of peak demand. (See below for a discussion of how storage, wind, and solar capacities are determined.) The natural gas combined cycle power plant is operated in baseload mode (80 percent capacity factor). The response to loads when the renewable generation is low is accomplished by withdrawal from storage and operation of a gas-turbine driven generator called the expander (see below).

The level of CO_2 reductions in this scenario is 80 percent relative to 2010, comparable to though somewhat greater than in the Nuclear/CCS scenario. This enables a comparison of CO_2 reduction costs between a scenario that has a conventional thermal generation approach (Nuclear/CCS scenario) with one that has a high level of renewable energy. In the Renewables/Natural Gas scenario, almost three-fourths of the generation in the year 2050 is from solar, wind, and geothermal resources. The rest is from natural gas.

The design of the wind, solar, and storage balance is discussed later in this chapter. Figure V-5 shows the generation mix and the changes in it in the 2010 to 2050 period in the Renewables/Natural Gas scenario. Note that the "compressed air energy storage (expander)" is the capacity of the gas turbine that generates electricity from stored compressed air that has been heated with natural gas. This is one of the essential elements of the system that enables a 12 percent margin to be maintained over demand at all times. The details of how the balancing is done between the solar, wind, and storage elements are discussed later in this chapter.

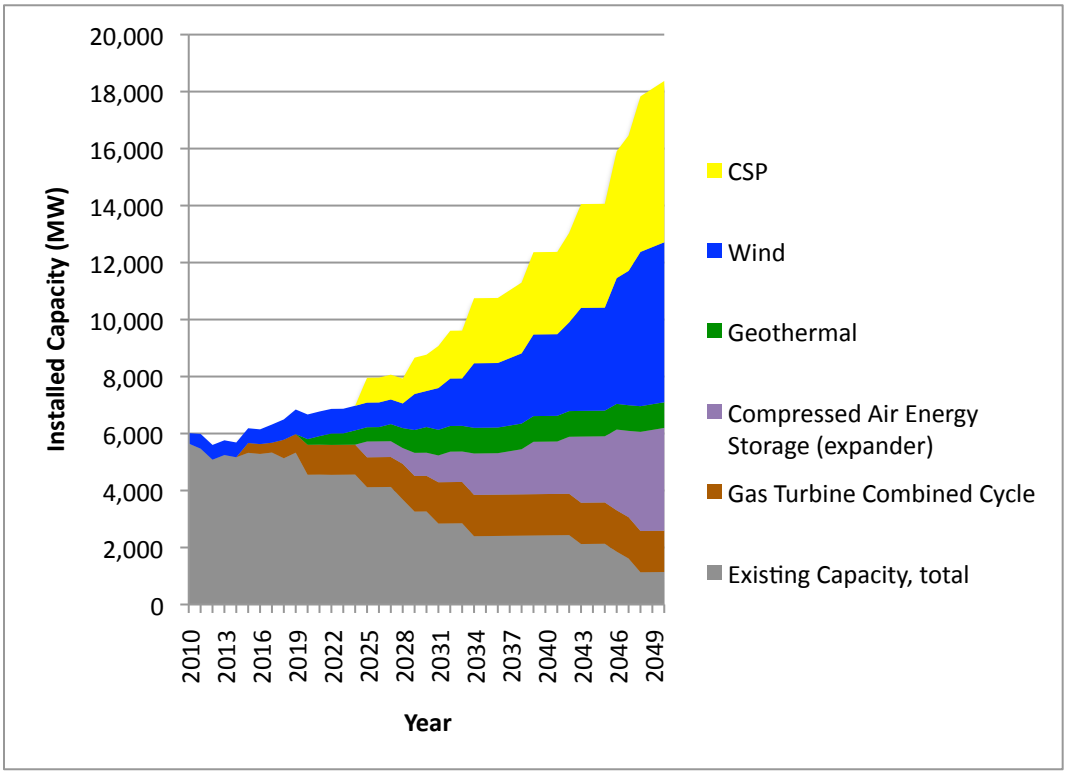

Figure V-5. The Renewables/Natural Gas scenario generation mix from 2010 to 2050.

Because the system in this scenario is not optimized, there is a great deal of spilled energy in this scenario—that is, there are many situations in which ample solar and wind generation is possible but there is no corresponding load at the time and the storage is also full. By the year 2050 about 30 percent of the solar and wind generation is spilled. Figure V-6 shows how spilled energy grows between 2020 and 2050 in the Renewables/Natural Gas scenario.

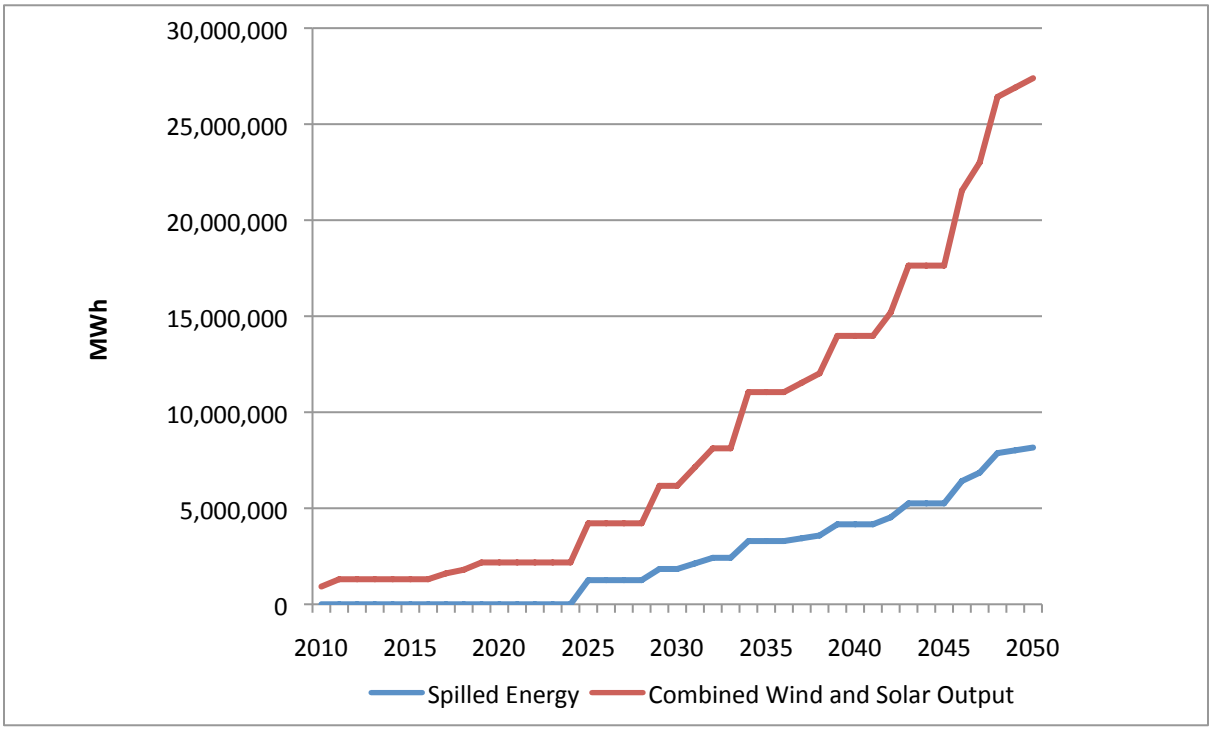

Figure V-6: Spilled energy growth in the Renewables/Natural Gas scenario.

4. Renewables/Natural Gas/CCS scenario

This scenario is a variant of the Renewables/Natural Gas scenario discussed just above. All generation elements are the same. Spilled energy is also the same. The main differences are in the amount of CO_2 emissions reduction and the corresponding additional cost incurred. This variant was created in order to make a second scenario that would be comparable in CO_2 emissions to the eUtah scenario. This was done by adding carbon storage to the combined cycle plants in the Renewables/Natural Gas scenario. While most discussion and research and development of carbon capture and storage is oriented to coal, due to its large place in the U.S. and global electricity sector, CCS could be accomplished at lower cost with combined cycle natural gas plants. Utah has both coal and natural gas plants; moreover, it is one of the leaders in CCS research, given the important role of fossil fuels in the state. This scenario provides some interesting insights for research and development in Utah and the benefits they might yield, not only for reducing CO_2 emissions but also in the field of energy R&D leadership. The added capital and fuel costs are embedded in a single marginal cost addition of $44 per MWh derived from the August 2010 federal Interagency Task Force on Carbon Capture and Storage.[62] Carbon emissions in the year 2050 in the Renewables/Natural Gas/CCS scenario would be about 93 percent less than 2010. The CO2 emitted from combined cycle natural gas plants would begin to be sequestered in 2040 at 30 percent and rise to 80 percent by 2050.

5. The eUtah scenario

In this scenario, the combined cycle natural gas plants are phased out by 2050. The only traditional fuel that is used is natural gas to reheat the compressed air when it is withdrawn from storage. This is essentially an all renewable scenario. Were the natural gas to be replaced by biogas for instance or by

[62] Interagency Task Force 2010 Figure A-9 (p. A-14)

battery storage, it would be 100 percent renewable. We have not assumed this, since battery storage for very large amounts of electricity is not yet a commercial technology. Further, the requisite amount of biogas may not be available in Utah, which does not have extensive bio-fuel resources, and may decide to use biomass resources for other applications, such as producing fuel for cars and trucks.

Forty-eight hours of storage at peak are included in this scenario. It is generally comparable in terms of CO_2 reductions to the Renewables/Natural Gas/CCS scenario. There is no carbon capture and storage in the eUtah scenario. Figure V-7 shows the generation capacity from 2010 to 2050 in the eUtah scenario.

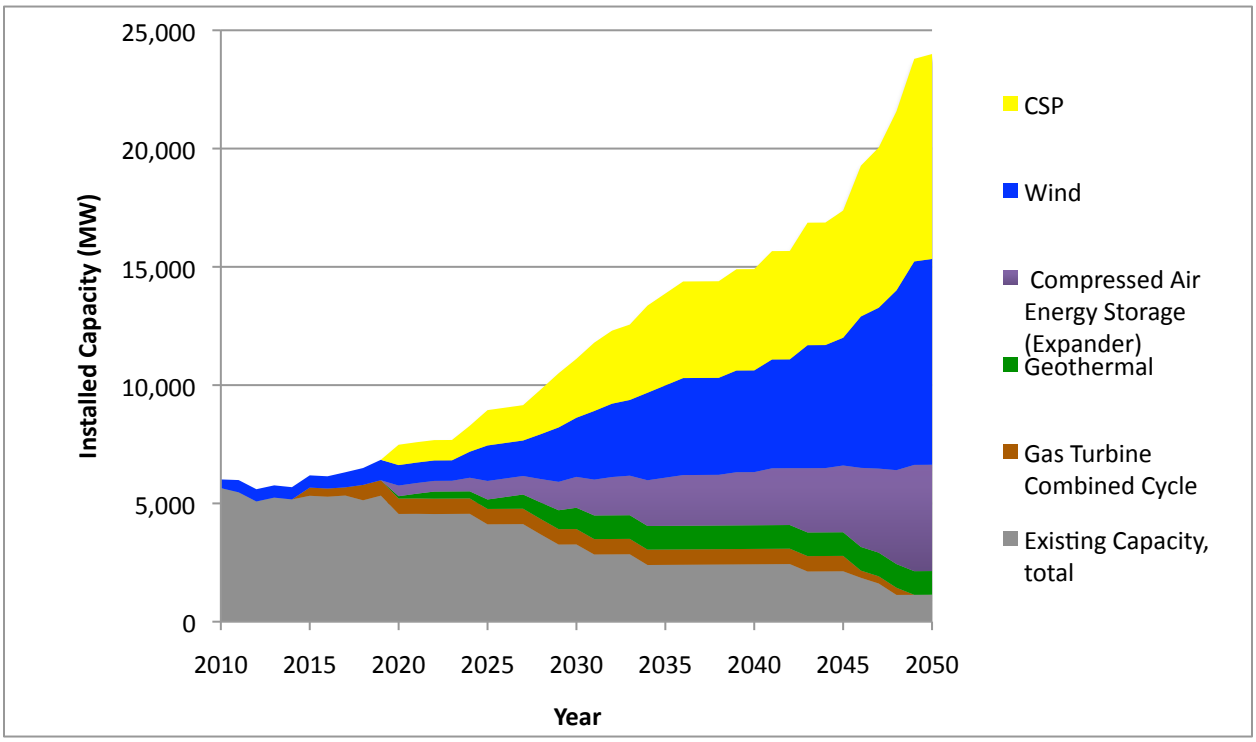

Figure V-7. The eUtah Scenario, based on solar, wind, and CAES, with 95 percent CO_2 reductions relative to 2010 and 97 percent relative to BAU in 2050.

Figure V-8 shows the growth of spilled energy from 2020 to 2050 in the eUtah scenario. The proportion of solar and wind energy spilled in the year 2050 is only marginally higher than in the Renewables/Natural Gas scenario (32 percent compared to 30 percent). However, the total amount of spilled energy is much higher since the total renewable generation is much higher in the eUtah scenario.

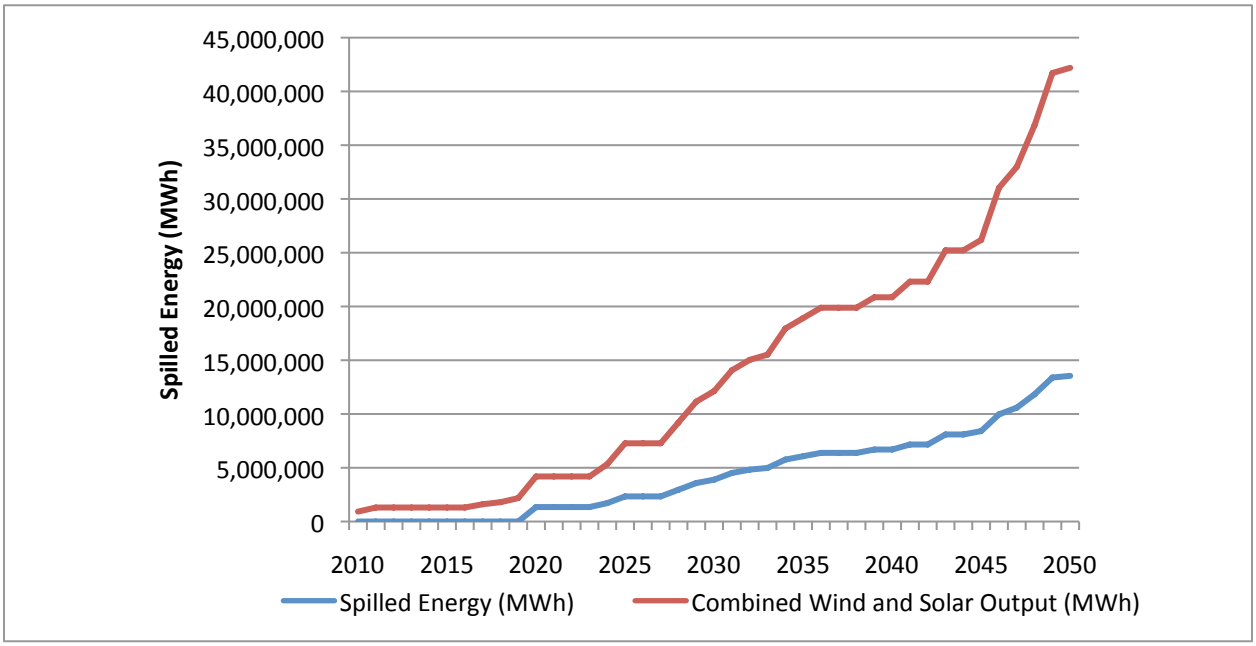

Figure V-8: Spilled energy in the eUtah scenario

C. Compressed air energy storage

There are only two large scale energy storage technologies that are commercial today that could be used with high penetrations of solar and wind energy: pumped hydro and compressed air energy storage (CAES). We do not consider pumped hydro in this study, since large scale pumped hydro in the eastern portion of PacifiCorp would require development of new hydropower facilities. Both location and cost of such facilities if they could be built at all are at present an open question. It is possible that hydropower facilities in Idaho, Washington and Oregon could be used in a pumped hydro mode in the long term. However, the water used in those facilities have multiple competing uses; indeed, the existence of some dams is contested because of adverse effects on salmon runs. Hence we have not considered pumped hydro storage in this report.

Compressed air storage is familiar in a number of everyday contexts, for instance, in the use of air under pressure storage in cylinders to power tools in road repair and automobile garages. However, compressed air has also been stored in large underground caverns for the purpose of reducing the use of natural gas fuel in peaking gas turbines in electricity systems. Two large scale commercial CAES systems exist. The Huntorf plant in Germany has a capacity of 290 MW and has been in operation since 1978. The McIntosh plant in Alabama is 110 MW; it has been in operation since 1991.[63]
Figure V-9 shows the configuration of a typical CAES system.

[63] Makhijani 2010a pp. 69-71. For CAES and wind energy storage see EPRI-DOE 2004. See also NREL 2006.

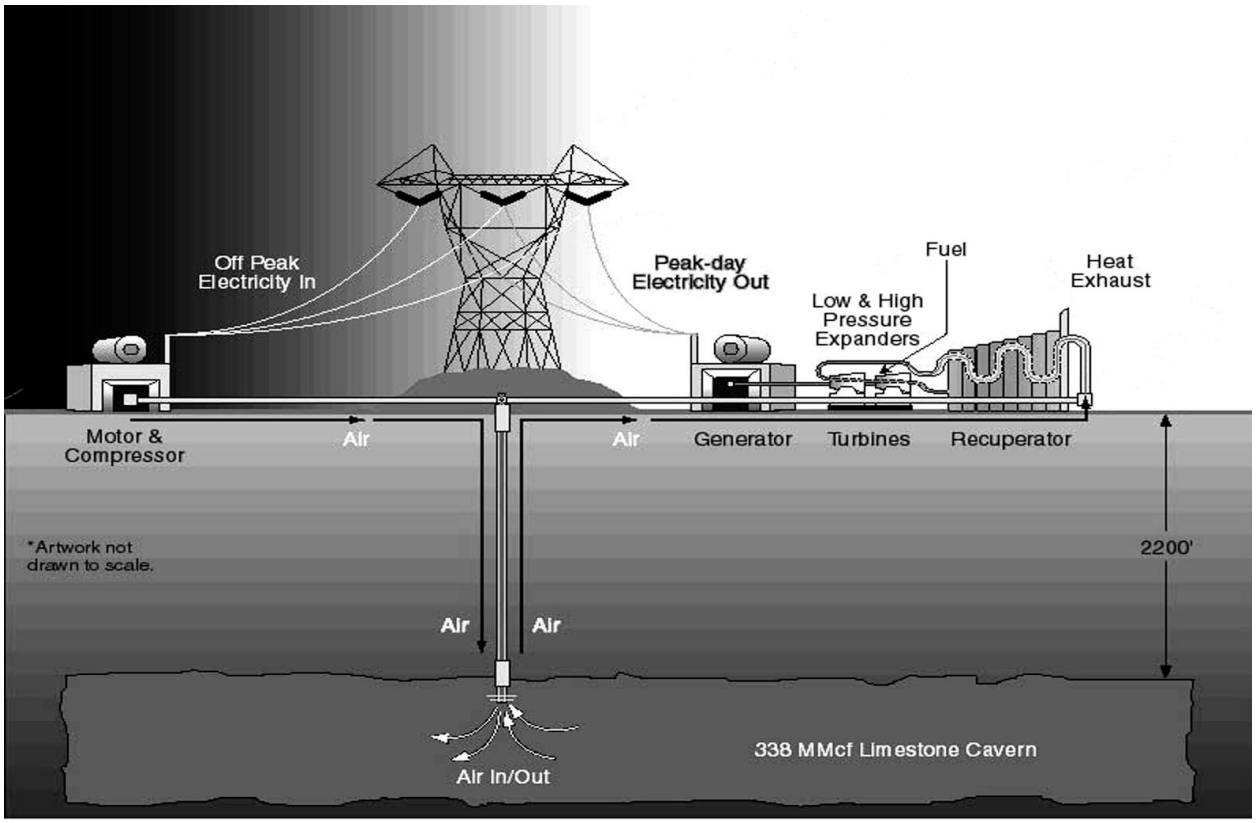

Figure V-9. Main elements of a Compressed Air Energy Storage system. Source: Sandia National Laboratory.

When electricity supply is greater than demand, it used to compress air, which is the "Motor & Compressor" element in Figure V-9. In the case of a coal-fired power plant being used to reduce peaking natural gas use, the compressor is operated at night using coal-fired electricity. In the case of a renewable energy system, the compressor would be operated when the total available supply (solar, wind, geothermal, and natural gas (if it is part of the scenario) is greater than the demand in any particular hour. The compressed air is stored in an underground cavern. It could be stored in a tank, but tanks are much more expensive than caverns and can be used for only relatively small amounts of storage. The caverns at Huntorf and McIntosh are in salt formations which were solution-mined to create the storage volume needed. This is a well-understood technology, since compressed natural gas is often stored in solution-mined caverns.

Compressed air can also be stored in aquifers—as a large bubble of pressurized air. As air is pumped into an aquifer, many bubbles form; these merge eventually into a single bubble as more air is pumped in. A cushion of residual pressurized air is needed to maintain the single bubble. The storage cavern is the second major element of a CAES system. Since most of the natural gas use in a single-stage gas turbine is for compression of air, the amount of energy needed to reheat the compressed air is much smaller than the total needed to generate electricity directly using a peaking single-stage gas turbine. About 4,500 Btu per kWh of natural gas is needed to reheat the compressed air, which is roughly 40 percent of the fuel required for a single natural gas turbine used for meeting peak loads. This turbine drives the generator. The turbine/generator set is the third major element of the CAES system.

Figure V-10 shows a National Renewable Energy Laboratory simulation of wind plus CAES as a baseload system. This contains all the elements discussed here for high penetration wind—surplus renewable generation for compression, withdrawal of compressed air for generation at times of deficit renewable supply, and spilled energy. Note the remaining gaps in supply. These can be filled with additional storage and/or some other element of electricity supply, such as geothermal energy. Figure V-10 shows various aspects of such a system, including wind farm electricity generation, the portion of generation used for compressing air and storing it, the portion of the energy that is spilled, and the electricity generated by withdrawal from storage.

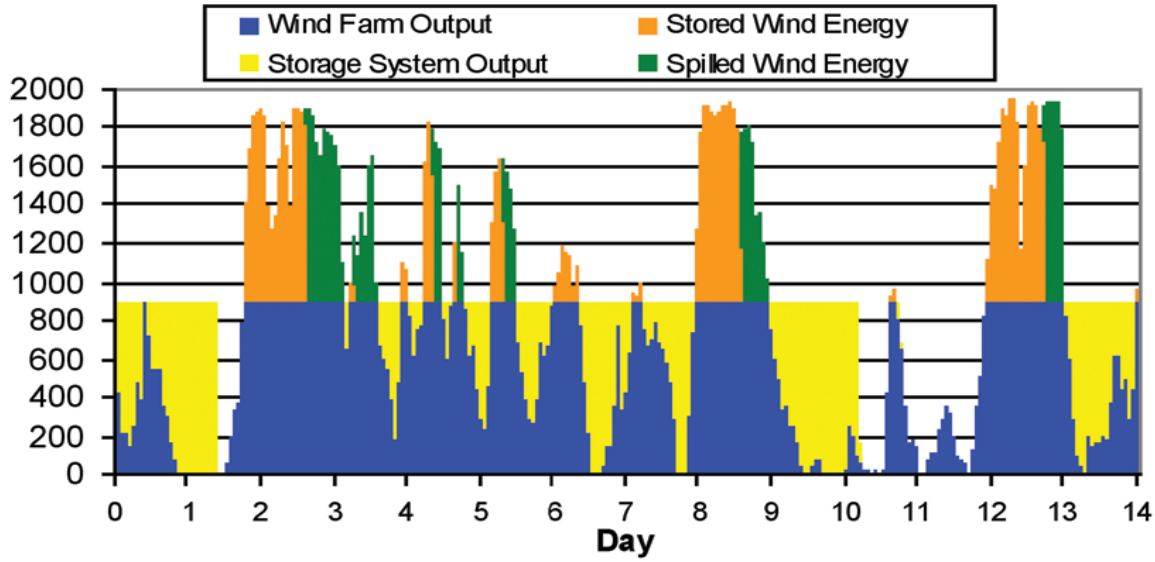

Figure V-10: National Renewable Energy Laboratory example of dispatchable wind with compressed air energy storage. Source: NREL 2006. This figure was developed by the National Renewable Energy Laboratory for the U.S. Department of Energy.

Energy is required for compressing the air and not all of it is recovered when electricity is generated from storage. Figure V-11, pertaining to the example in Figure V-10, from the National Renewable Energy Laboratory, shows the energy flow in a CAES system. Note that in this example, spilled energy is only about 8 percent of total generation (range 5 to 15 percent). This appears to be because some gaps were left in the generation to be filled in from other sources. The heat rate—that amount of natural gas used to reheat the compressed air is about 4,500 Btu per kWh. However, since most of the wind-generated electricity is supplied directly to the grid, the amount of natural gas needed per unit of electricity dispatched into the grid is much smaller. In the baseload example, it is estimated at under 1,000 Btu per kWh. Finally, the greenhouse gas emissions are estimated at 40 to 80 grams per kWh dispatched—about 4 to 8 percent of the emissions of a conventional coal-fired power plant.

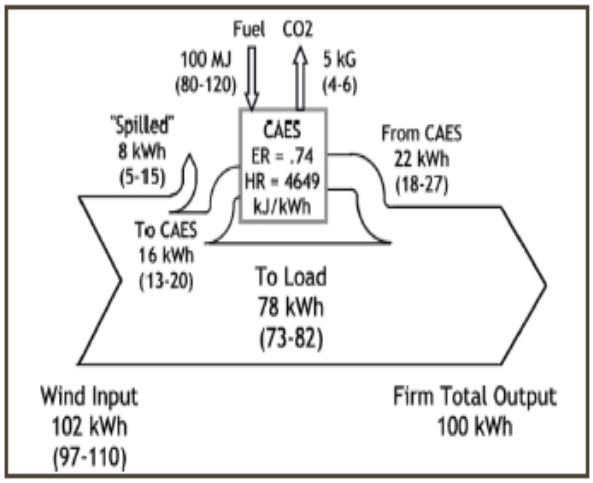

Figure 4: Energy Flow through a Baseload Wind Power Plant

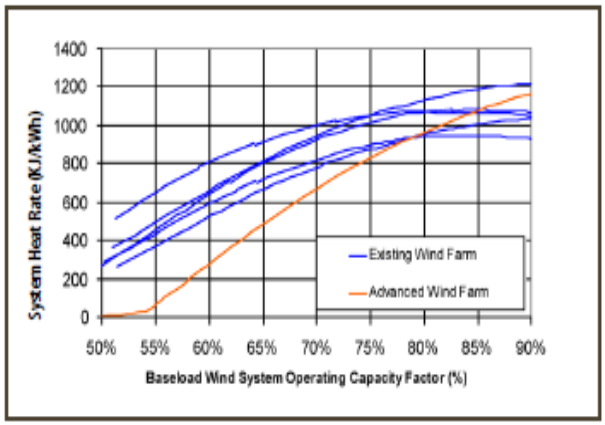

Figure 5: Baseload Wind Plant Fuel Requirements

Figure V-11: Energy flows and overall input of natural gas required from a CAES system coupled to a wind farm. Note: "kJ" stands for "kilojoule," which is a unit of energy equal to about 0.95 Btu. Source: NREL 2006. These figures were developed by the National Renewable Energy Laboratory for the U.S. Department of Energy.

We assume that the overall round-trip efficiency of the compressed air system is about 75 percent—that is for every 100 kWh used to compress air, 75 kWh of electricity output will be dispatched into the grid. In the renewable scenarios in this study, losses due to CAES use constitute about 3.3 to 3.4 percent of the solar and wind electricity output. These are only about a tenth of spilled energy, which is the main loss in the system as modeled here.

There are many areas that would be suitable for siting CAES caverns in the United States based on technical considerations alone. Figure V-12 shows a U.S. map of potential CAES caverns in salt or aquifers. As is clear from Figure V-12, Utah has many potential locations for compressed air energy storage, including in solution-mined salt caverns or in aquifers. That said, we recognize that siting will likely be a challenge in realizing this storage potential, especially if a mainly centralized approach is taken to solar and wind development. The siting challenge would be greatly reduced by including elements of storage in the distribution part of the grid and reducing storage requirements through demand dispatch when relational system peaks occur.

The CAES facility does not have to be co-located with the renewable energy system. There are advantages and disadvantages to co-location. The significant economic advantage is better use of transmission capacity, since intermittency is overcome at the wind or solar site by storage. The disadvantage is that the best sites for solar and wind energy may not have suitable sites for CAES. Utah appears to be fortunate in that the large area with potential for CAES siting could allow co-location of renewable and CAES systems. A cautionary note is in order here. We have not examined CAES siting issues such as overlap with national parks, populated areas, and environmental impacts. But since UREZ solar and wind sites have examined such factors, and since we have used the UREZ sites as our starting point, the issue of siting may not be as difficult as it might be in the absence of such considerations.

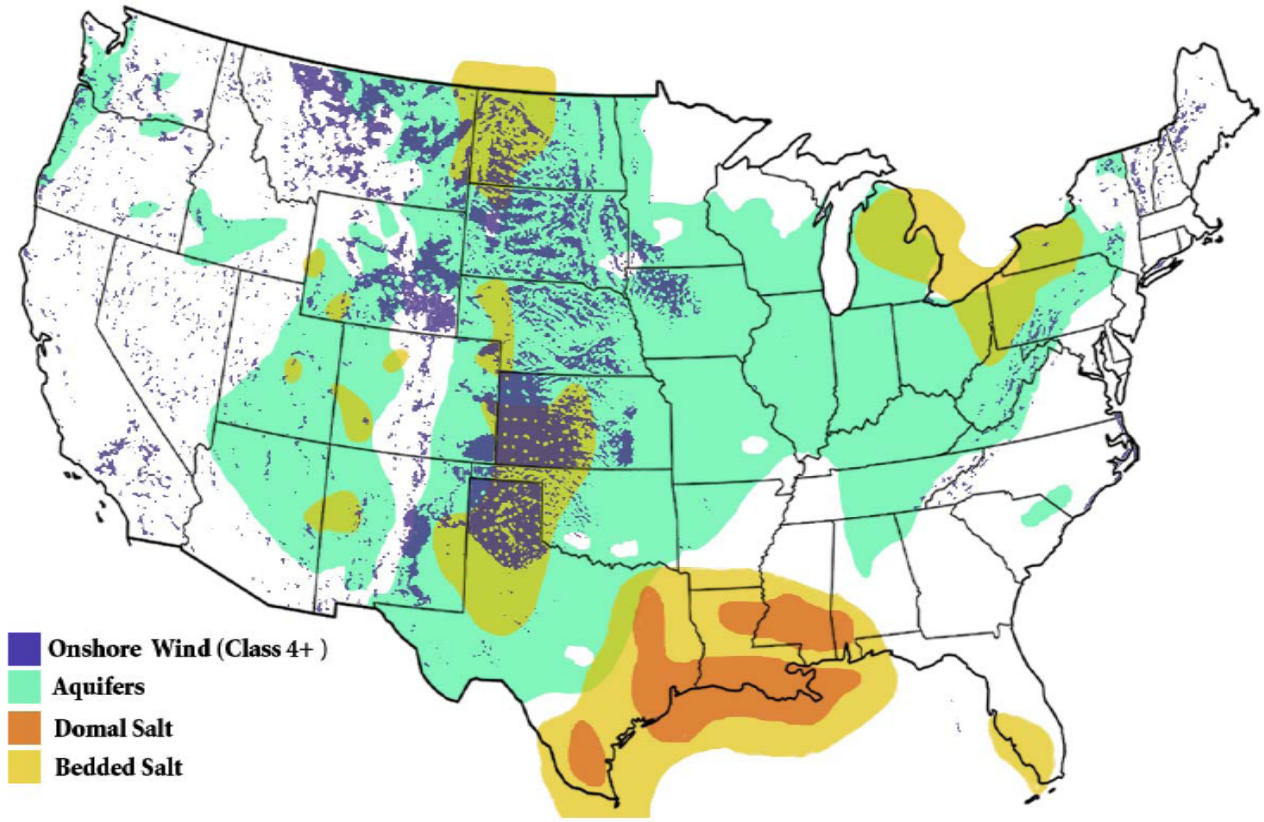

Figure V-12: Areas in the United States with potential for siting CAES storage.

Development of one or more CAES systems in Utah has been considered. PacifiCorp included CAES in its 2008 IRP as a possible resource option starting in 2014, but the 2010 IRP update indicates no active plans to actually pursue such an option.[64] The 2010 IRP only notes the potential need for storage in the "longer term" beyond 2020 as part of reducing CO_2 emissions in case of carbon restraints. But even in this context a CAES system is not explicitly mentioned, while a battery system and nuclear power are:[65]

[64] PacifiCorp 2008 p. 18 and PacifiCorp IRP 2010
[65] PacifiCorp IRP 2010 p. 21

> Relatively speaking, the potential requirements to reduce greenhouse gas emissions could have a profound impact on PacifiCorp's generation fleet. In the near term (e.g., through at least 2020), to reach the emissions caps proposed in the federal bills, PacifiCorp would need to consider converting coal units to burn natural gas and retiring other coal units and replacing them with lower carbon emitting resources and expanded DSM. In the longer term, replacement of baseload fossil-fueled plants with non-emitting baseload resources currently in development (e.g., carbon-sequestered thermal units, new generation nuclear units, and renewable generation supplemented with battery storage) will be necessary to achieve reduction targets such as those in the federal bills, assuming continuation of the energy policy that requires electric utilities provide service on demand in the quantity demanded.

The lack of active plans for acquiring a CAES site while keeping open much costlier options such as battery storage and nuclear power, does not appear to correspond to maximizing flexibility and opening up low risk options in the event of significant carbon restraints. Further, PacifiCorp plans to have about 1,000 MW of wind capacity in its East sector. This could be converted to dispatchable capacity using CAES.

While PacifiCorp does not appear to be active in the development of CAES in Utah, another company, Magnum Gas Storage is actively pursuing such a site near Delta, Utah, about 140 miles by road, southwest of Salt Lake City. More than one cavern is planned. Each cavern would be "3,300 feet [about 1,000 meters] underground and measure 300 feet [90 meters] in diameter and 1,200 [360 meters] feet deep." The caverns would be solution-mined salt caverns. Based on the measurements cited, the volume of each cavern would be about 2.3 million cubic meters. The first cavern would be used for compressed natural gas storage.[66] This would also provide a suitable base for providing natural gas for a subsequent CAES system.

The maximum storage pressure in a CAES system is a design feature that would partly depend on factors such as cavern characteristics and maximum anticipated length of storage time over which leakage needs to be minimized. The Huntorf plant storage pressure is 70 atmospheres with a cavern of 300,000 cubic meters. The McIntosh plant in Alabama operates in the 45 to 74 atmospheres range, with a cavern volume of 5.32 million cubic meters. At capacity, it supplies almost 3,000 MWh of power output over the course of 26 hours.[67] Note that the CAES total storage requirements for centralized renewable systems are very large in comparison (see Table V-1 below).

D. Modeling a centralized renewable energy system

A renewable energy system can be designed with or without significant non-renewable, conventional resources, such as gas turbine combined cycle plants. We have chosen the following approach:[68]

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[66] O'Donoghue 2009

[67] Gandy 2000 pp. 18-20. See E.ON Kraftwerke 2010 for the recent history of the Huntorf plant.

[68] The basics of the approach, matching demand, supply, and storage for one year, were designed by Dr. M.V. Ramana of Princeton University as part of a study on renewable electricity supply for Minnesota, currently under development at the Institute for Energy and Environmental Research. The model was further developed by Arjun Makhijani as part of this study. Carbon emissions, reliability of supply (12 percent peak margin), projections over time, levelized costs, estimation of dispatchable capacity, and other features were developed for this report.

- A reference year in the recent past is chosen in order to devise the parameters for future renewable energy projections. The year chosen was 2003. This corresponds approximately to the period over which renewable energy data were complied, though some data covered more than one year, due to constraints on availability of measurements from various sites.
- Hourly demand data were compiled.
- Hourly data from a variety wind and solar sites were combined.
- Provision was made for different levels of baseload generation, with 2 possible sources. We used geothermal and gas turbine combined cycle plants. The latter is used in the Renewables/Natural Gas scenario and its variant with CCS.
- Provision was made for storage. A single type of storage was used—compressed air energy storage. The total amount of energy storage can be adjusted so as to satisfy reliability requirements for all hours in the year, in combination with other elements, notably the amount of solar and wind capacity and the size of the expander (gas turbine generator in the CAES system).
- The compressor size is chosen as being equal to the largest amount of surplus power over demand in the year.
- The expander power is chosen so as to meet the largest deficit requirement plus some reserve requirement in combination with storage.
- The available capacity is equal to demand plus 12 percent for each hour in the year.
- A manual adjustment of solar, wind, expander, and storage capacity was done so that a small variation in any element drops the minimum reserve capacity below 12 percent. There are many different combinations of the four variables possible of course. The manual adjustment using this criterion provides a minimal balancing of the system to ensure that costs are not unnecessarily high. However, since the costs of various elements are not integrated into this balancing of the elements, it is not a least cost approach.

Since the reserve margin requirement is met for all hours, the reliability of the renewable system is the same as that of the present system. The startup time of the CAES system is on the order of 10 minutes.[69] Once this criterion is satisfied, the fraction of peak demand supplied by the combination of solar, wind, and CAES can be computed.

Some detail on the calculation of the dispatchable fraction of solar and wind is helpful, since it is so important to the calculation and to showing that solar wind and storage can meet the same reliability criterion as conventional sources of electricity.

The geothermal and combined cycle power plant capacity is subtracted from the peak demand plus 12 percent. The balance of the demand is supplied by wind, solar, and generation from storage, since the system is designed to meet the maximum demand plus 12 percent reserve. The ratio of the portion of the demand met by the solar/wind/storage system to the total solar and wind capacity is the dispatchable fraction of wind and solar supply. Sufficient total dispatchable capacity must exist to meet the demand that is not met by geothermal plus combined cycle capacity.

Mathematically, let:

- **D** be the peak load plus 12 percent,
- **B** be the geothermal plus combined cycle capacity,

[69] Gandy 2000

- **S** be the solar capacity,
- **W** be the wind capacity
- **f** be the fraction of solar plus wind capacity that can be counted as dispatchable when enough solar, wind, and storage capacity (including the expander) is installed to meet the 12 percent reserve requirement throughout the year.

The dispatchable demand fraction, **f**, is then:

$$f = (D-B)/(S+W)$$

If the wind and solar fractions are kept the same as the ratio in the reference year, then **f** always gives the dispatchable fraction that can be attributed to the combined wind and solar capacity. This is used to determine the capacity of solar, wind, and expander needed in any year.

The approach of keeping the ratios of solar, wind, and expander fixed simplifies the computations because balancing of the different elements in the renewable system is automatic. Further, the fraction of generation contributed by baseload is kept at about the same level in the year 2050 as in the reference year (2003 in this report). Note that variations in solar and wind supply from year to year are not taken into account in this analysis.

The following features emerge for the renewable energy scenarios (Renewables/Natural Gas and eUtah)[70]:

- The dispatchable fraction in the Renewables/Natural Gas case is much higher than in the eUtah case—about 48 percent compared to only 36 percent. This shows that going to a very high proportion of solar and wind in a centralized mode that is not optimized results in rapidly diminishing capacity value of marginal additions to solar and/or wind capacity. The other side of the coin is that small additions to baseload capacity when solar and wind are at very high penetrations rapidly increase the value of the remaining solar and wind capacity.
- While the fraction of spilled solar and wind energy is comparable in the two cases, the total amount of spilled energy is much higher in the eUtah case: 13.5 million MWh in the year 2050 for the eUtah case compared to 8.2 million MWh for the Renewables/Natural Gas case.
- Utah solar and wind data indicate that the ratio of wind to solar capacity should be about one to one in a system with high penetration of renewables. Solar provides a good match with the load in the summer. Wind is needed in the winter when solar supply is low.
- Losses due to storage are small—about 3.3. to 3.4 percent of the solar and wind generation is lost in the CAES system, assuming a 75 percent overall efficiency.
- As expected, the amount of storage needed increases (by about 40 percent) one goes from the Renewables/Natural Gas scenario to the eUtah scenario.

Figure V-13 shows the spilled energy in the eUtah scenario in the reference year. Note that the spilled energy occurs in the middle of the year, including in the summer, while there is far less in the winter. As

[70] Note that the Renewables/Natural Gas scenario remains the same except in amount of carbon emitted and costs when carbon capture and storage is added to it. The added natural gas use and lower efficiency is included in the added costs of CCS.

discussed above, this is because the mismatch of supply to demand in Utah under the modeled mix is much greater in the winter than in the summer even though the demand is much higher overall in the summer. This is because of the far lower availability of solar energy in the winter. During periods of low winter wind, stored energy is called upon more often. In contrast, in the summer, both solar and wind are available and storage tends to be full more often, leading to more spilled energy. The same is true of the spring and the fall.

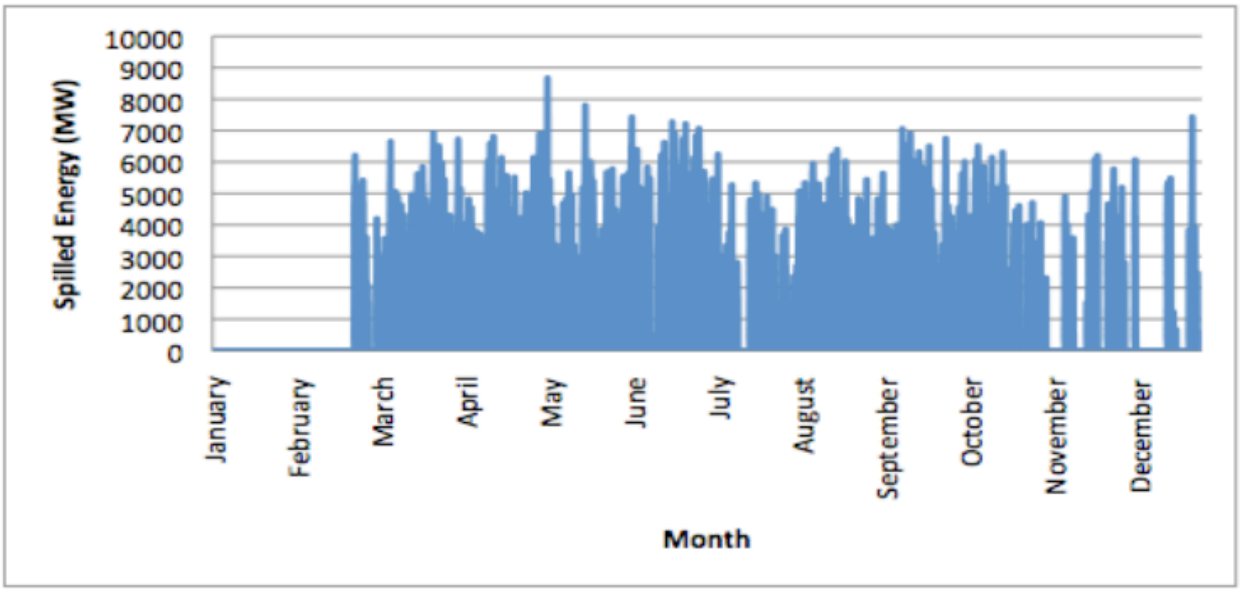

Figure V-13: Spilled energy in the reference year (2003) in the eUtah scenario

Figure V-14 shows spilled energy in more detail in an autumn week in the reference year. Energy is spilled in the early and late parts of the week. The white area between the demand curve and the generation from storage is directly supplied by renewable energy generation at that time.

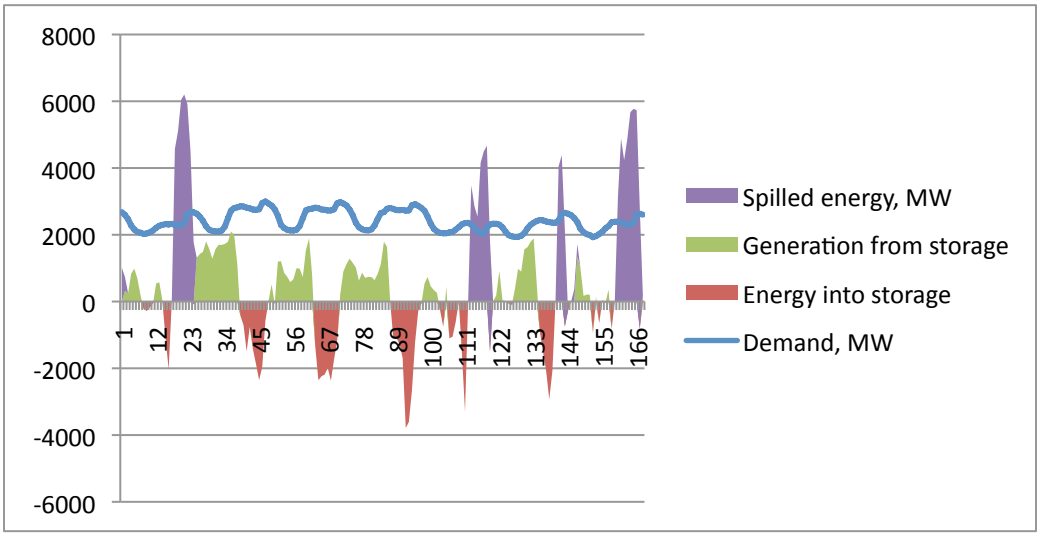

Figure V-14. Generation from storage, energy pumped into storage, and spilled energy in a fall week.

The problem of spilled energy has no easy fix within this single storage, centralized framework because it is seasonal. For instance, adding battery storage does not help, since batteries typically store energy

for short periods of time. Similarly, adding molten salt storage to the solar system does not signficantly change the picture in this case, because such storage is most effective in the summer while the relational system peak occurs in the winter for the wind and solar data used here. Reducing spilled energy will mean thorough system redesign with distributed storage and generation, generation-driven loads, optimization of building design with renewable system design, additional of demand dispatch, possibly as an year-round feature of the system, etc.

Table V-1 shows the main parameters that result from this analysis for the Renewables/Natural Gas scenario and for the eUtah scenario. Note that the cavern storage requirements are very large. This may present siting problems. But, like the problem of spilled energy, the size of the storage requirements underlines the need to optimize investments on the consumer side and centralized generation side of the electricity system. Demand dispatch to reduce the relational system peak, efficiency increases in key areas as well as local, substation-level storage (using sodium sulfur batteries, for instance) could all be important elements of creating a balanced, optimized system that reduces the scale of CAES storage estimated here.

Table V-1: Summary of parameters dervied from modeling a reference year (2003) for the renewable scenarios

	Renewables/Natural Gas scenario	eUtah scenario
Ratio of wind to solar capacity	1.01	1.00
Ratio of expander capacity to wind plus solar	0.32	0.26
Ratio of compressor capacity to expander capacity	2.42	2.92
Peak load in 2050 (high efficiency case), MW	7,143	7,143
Hours of storage capacity at peak load	34	48
Wind and solar capacity value fraction	0.48	0.36
Hours per year of expander use at rated expander capacity	757	935
CAES losses as percent of wind and solar energy generation	3.3	3.4
Spilled energy as a percent of solar and wind generation	30	32

Note: All values are rounded. Peak load is the maximum demand excluding reserve margin.

VI. Economic Considerations

A. Introduction

The major goals of the cost analysis are to:

- Determine the total cost of electricity generation in the year 2050 in absolute terms and as a fraction of the Utah economy. (We assume that 80 percent of the electricity in Utah and the same proportion of the economy is in the PacifiCorp region).
- Make explicit the cost of reducing CO_2 in each of the low CO_2 scenarios, using the BAU scenario as the basis for comparison. The variant of Renewables/Natural Gas is evaluated for comparing costs with the eUtah scenario. Two comparisons are done: one relative to BAU in 2050 and one relative to estimated emissions in 2010.
- Estimate the impact of costs of various levels of water use for electricity generation.
- Lay the basis for doing sensitivity calculations, in which capital and fuel costs can be varied to estimate the potential range of costs for each scenario.
- Estimate the amount of capital committed to generation projects in the pipeline at any time due to construction.
- Estimate the financial risk associated with continued carbon emissions that are greater than 20 percent, relative to the year 2010, by the year 2050.

In keeping with the design of the scenarios, the cost estimates allow the estimation of carbon costs for various levels of CO_2 reductions using conventional thermal or renewable technologies.

The basic approach for estimating generation cost is to estimate unsubsidized levelized costs for each new power plant built. *No loan guarantees, production tax credits, or investment tax credits are taken into account.*[71] This approach allows an "apples-to-apples" comparison between generation options. But it is not without its problems and dilemmas. We exclude special tax treatment of different electricity sources, which have a large effect on practical decisions but which distort economic comparisons. For instance, both wind and the first few nuclear power plants can benefit from a substantial production tax credit. This is not included in the calculations in the present study. A single effective cost of capital is used to compute the levelized cost estimate. This framework is sufficient to fulfill the comparative purpose of the cost estimates and to provide a general indication of the level of risks associated with the various approaches to reducing carbon. It also suffices to estimate the risk of not reducing carbon, since a range of costs of doing so is computed for four scenarios.

One problem in creating a market-based apples-to-apples comparison with no subsidies is that new nuclear power plants cannot currently be financed on the open market, since Wall Street considers them too risky. Either federal government loan guarantees and financing or construction work in progress (advance, interest-free payments from ratepayers) or both appear to be required to finance them. Recently, Constellation Energy pulled out of a plan to build a new nuclear reactor, in partnership with the French company EDF, despite the offer of a government loan guarantee for a fee, indicating

[71] UREZ estimates include tax credits and are therefore not used in this study.

that even the very significant risk reduction offered by such guarantees is insufficient to overcome the underlying risks of nuclear projects. Advance, strings-free, interest-free payments from ratepayers appear to be the only way a few reactor projects are actually proceeding significantly beyond paperwork. Since no project has successfully been financed on the open market, it is difficult to estimate the cost of capital that should be attributed to nuclear projects. We also note that the first reactors have been given production tax credits on a par with wind energy projects. The latter have been proceeding apace, while nuclear projects still have not been financed on the open market. Hence a spread between wind (as well as natural gas) projects to reflect the greater risk of nuclear is justified.

To assess the spread, we examined current rates for commercial projects being financed with high yield bonds ("junk bonds" in popular parlance) without government loan guarantees with 10-year and 30-year U.S. Treasuries, which are considered the safest long-term investments. We also examined historical spreads between these two types of investments. We set the base case cost of nuclear financing at the higher end of these yields (even though nuclear projects cannot be financed. This gives an estimate of about 12 percent for the unsubsidized cost of capital for new nuclear projects—which amounts to a 4 percent differential compared to relatively low-risk electricity sector investments.[72] For sensitivity calculations we use a two percent variation on either side of 12 percent.

We have not directly taken into account uncertainties related to nuclear waste, notably spent fuel management or potential increases in costs associated with reprocessing, fuel cost increases, and onsite storage of spent fuel for prolonged periods beyond the licensed lifetime of the plant. We have done a sensitivity check varying the cost of fuel and non-fuel overhead and maintenance costs. The high-end of nuclear operations and maintenance (O&M) costs were taken from the Keystone Joint Fact-Finding.[73] Since these are considerably greater than present costs, it represents cost increases in all aspects and could be taken to include the uncertainties in spent fuel management.

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[72] Because nuclear projects are not presently being financed we use rates associated with risky projects currently being financed. Distressed bonds and other high risk bonds, are referred to as non-investment grade bonds, high-yield bonds or, popularly as "junk bonds." Distressed bonds, which are the lowest grade investments, can command a 10 premium over risk-free securities. U.S. Treasuries are generally considered to be risk-free. Stressed securities have a 6 to 8 percent premium. Near the end of October 2010, 10-year Treasuries were at 2.625 percent, while 30-year Treasuries were at 3.875 percent. See Bloomberg quotes at http://www.bloomberg.com/markets/rates-bonds/government-bonds/us/, viewed on 24 October 2010. The historical spread in promised yield between high yield bonds and 10-Year Treasuries in the 1980s and 1990s has varied a great deal. Its high was 8.75 percent in 1990 (Altman 1998 Figure 1 (p. 4)). A view longer than 10 years for nuclear projects is warranted since they are heavy industry capital projects. Hence comparison of the spread with 30-year U.S. Treasuries should also be made. In view of the fact that the foregoing rates apply to projects that have been financed with high yield bonds without government loan guarantees, and that Wall Street refuses to finance nuclear power plants at all, a 10 percent to 14 percent range for cost of capital for nuclear projects is reasonable for an apples-to-apples comparison with projects that are being financed. The 10 percent dividend guaranteed to Warren Buffett when G.E. raised $3 billion from him (by issuing preferred stock) during the crisis in G.E. Capital in 2009 (Lohr 2010) provides a strong indication that the lower-end of the range of 10 percent is a very favorable assumption for nuclear, which cannot be financed. New nuclear reactors have been described as "bet the farm" risks on Wall Street because the capital costs of single projects are comparable to and sometimes greater than the entire market capitalization of the companies proposing them. This is a large part of the reason they cannot be financed on the open market. See Makhijani 2010b for more details.

[73] The *Nuclear Power Joint Fact Finding* (Keystone 2007) table on p. 11 is used for the upper limit of fuel and non-fuel O&M costs. The committee that wrote the report included academics, nuclear industry representatives, and environmental NGO representatives.

Another signficant problem in an apples-to-apples comparison is that carbon capture and storage is not a commercial technology in the electricity generation sector. This is the only technology that we have included in this study that does not have a large scale operating example in the electricity sector. However, there is sufficient literature as well as operating experience in injecting CO_2 into geologic formations in the oil and gas industry to include it, given its potential importance in the electricity sector.

The 2010 Interagency Task Force of the federal government has estimated a range of costs of CCS at $60 to $95 per MWh.[74] When $80 per MWh is added to the levelized cost of new coal-fired power plants estimated in this study, the result is about the same as the base case cost for nuclear—about $150 per MWh. For convenience, we lump nuclear and coal with CCS together in the base case, and assume that the low and high estimates for coal with CCS is about the same as for nuclear in the sensitivity calculations. This assumption simplifies the analysis since CCS costs are currently difficult to estimate because it is not yet proven on a large scale in the context of electricity generation. In the Renewables/Natural Gas case, a cost of $44 per MWh is added to the levelized cost of generation for the carbon capture and storage that would need to be associated with the plant.

Two other uncertainties are noteworthy. One is, of course, the variation in natural gas costs. An initial choice of $5 per million Btu is made here as recommended during the meeting of the Advisory Board for this project in Salt Lake City on October 27, 2010. The range of $3 to $10 that is used in the sensitivity calculations was recommended by the Advisory Board earlier in the study process and was reaffirmed during the October 27, 2010 meeting. Natural gas price variation, while important, is not a major uncertainty in this study, since natural gas is not the major part of generation in any scenario.

There is considerable uncertainty in the projected cost of solar technology. These costs have been declining rapidly. PV capacity is growing dramatically as are orders for concentrating solar power. But the industry is at the start of a commercialization process. If it proceeds smoothly, the goal sought by many, and advertised as RE<C [Renewable Energy cheaper than Coal] by Google, may be achieved in ten years. As noted earlier in this report in Chapter V, the Department of Energy has set a goal of achieving $1 per peak watt for central station solar PV by the year 2017. Even if this target date were to be missed by five or ten years, it would make a dramatic difference in the prospects for solar energy. Yet, we have not chosen to use the lowest projections of cost available for solar technology since that might be considered speculative or at least too optimistic at this point.

For the base case, we assume an overnight cost of dry CSP at $2,000 per kW (and an "all-in" cost of $2,200 per kW). Overnight cost is the cost that would be incurred if all the equipment were purchased at once and built immediately—hence the term "overnight cost." The all-inc ost includes allowance for funds during construction, including the interest that accrues on money borrowed to build the plant. The longer the lead time, the higher the ratio of all-in to overnight cost, all other things being equal. A higher cost and a lower cost ($3,000 per kW and $1,500 per kW) are considered in the sensitivity calculations. A number of different sources were consulted for selecting capital costs. For combined cycle natural gas power plants, we have simply used the PacifiCorp 2010 value for the eastern section of its service territory.[75] For fossil fuel and renewable power plant types, we consulted a comprehensive California Energy Commission report on generation costs.[76] Since California's renewable portfolio goals

[74] Interagency Task Force 2010
[75] PacifiCorp IRP 2010 Errata Table 4.3
[76] CEC 2009

will likely constitute a very large portion of the new renewable capacity in the Western Interconnection in the coming decade, this is a very important report. We also consulted the Annual Energy Outlook report of the Energy Information Adminstration and the *Report of the Interagency Task Force on Carbon Capture and Storage*.[77] Nuclear costs were based on Wall Street and utility industry estimates from ongoing projects in Florida and Texas.

In addition to the base case costs of each scenario, we also did a sensitivity analysis, varying fuel, overhead and maintenace costs, and capital costs in those cases where the results are especially afffected by such changes, as for instance natural gas prices or nuclear plant capital costs.

B. Levelized costs

The following parameters were used for the levelized cost calculations:

- Inflation rate for fuel and O&M cost assumed = 2 percent
- Nominal discount rate for calculating levelized cost = 6 percent.[78]

Levelized costs are calculated in the usual way using the formula:

$$\textbf{Levelized cost} = \Sigma_T\,[(I_t + M_t + F_t)\,(1+r)^{-t}] \,/\, \Sigma_T\,[E_t*(1+r)^{-t}]$$

Where
I_t = Investment-related payments in the year t
M_t = Operations and maintenance expenditures in the year t
F_t = Fuel expenditures in the year t
E_t = Electricity generation in the year t[79]
r = Discount rate
T= lifetime, sum is from 1 to T years.

Capital costs and results for the base case are shown below.

Table VI-1 Capital costs used for constructing the base case cost estimates

All-in capital costs, $/kW, except cavern	
Nuclear (Note 1)	$8,000
Coal no CCS, BAU	$3,000
Natural gas combined cycle	$1,250
Wind	$2,200
Concentrating solar power, no storage (Note 2)	$2,200
Geothermal Utah average	$5,300
CAES compressor	$300
CAES expander	$400
CAES balance of system	$300
CAES cavern $/kWh (Note 3)	$3

Notes: 1. Nuclear cost estimates for new projects vary a great deal and have been esimtated in the range of $6,000 to $10,000 per kW (all-in costs, including allowance for funds during construction). The Florida Power and Light analysis [delivered] to the public utilies commission of that state estimates all-in costs for nuclear as 75 percent

[77] EIA 2010a, levelized cost section. Also Interagency Task Force 2010.
[78] The discount rate net of inflation is 4 percent.
[79] Constant annual generation, E, is assumed in this study = installed capacity*capacity factor*hours in the year. This means that the denominator = $E*\sum_T(1+r)^{-t}$, where t goes from 1 to T. The capacity factor is different for the various technologies, as explained below, but in each case it is kept constant.

larger than overnight costs.[80] Hence a range of $4,000 to $6,000 for all-in costs translates into a cost range of about $7000 to $10,000. This range of all-in costs is also indicated by other industry data. The Progress Energy project in Florida is estimated at $22 billion for 2,200 MW, but this includes about $3 billion for transmission. Net of transmission, the cost is over $8,600 per kW. It should be noted that both projects are heavily subidized by a Construction Work in Progress charge to ratepayers. The South Texas Project of 2,700 MW is estimated at $18.2 billion, or about $6,740 per kW, but it should be noted that even before project construction began costs estimates rose more than three-fold from less than $6 billion in 2007 to $18.2 billion in late 2009.[81]

2. No concentrating solar power plants are included in this study until 2020 (in the eUtah scenario) and until 2025 in the Renewables/natural gas scenario. The estimated cost used for CSP in the 2020 to 2050 period is projected for the 2020 to 2030 decade. See, for instance, CEC 2009, p. 20

3. The CAES cavern cost is $3 per kWh. For CAES, EPRI-DOE 2004 has been used as the basic source.[82] The capital costs for CAES in the EPRI-DOE report have been doubled for 2010, in keeping with the cost escalation of wind and NGCC, and kept constant thereafter. No cost reduction due to extensive deployment is assumed. The cavern cost for solution-mined salt caverns in the EPRI-DOE report is estimated at $1.75 per kWh for a 10-hour storage cavern, with costs going down for larger storage times and vice versa (EPRI-DOE 2004 Table 15-1 (p. 15-3)). Since the storage amounts in this report are longer than 10 hours, a reference value of $1.50 was assumed in the context of the study and doubled to $3/kWh to bring it in line with the cost increases for most other energy projects.

Table VI-2 Parameters: Parameters used for different energy technologies

Technology	Net cost of capital	Life, years	Capacity factor	Total O&M, including fuel, $/MWh
Nuclear	12%	40	90%	$20
Combined cycle natural gas	8%	30	80%/35% See note 6	$39.50
Wind	8%	25	29%	$10
CSP	8%	25	27%	$25
Geothermal	8%	40	85%	$20
Coal no CCS	8%	40	80%	$28.80
CAES Expander/Compressor	8%	25	Variable	variable
Cavern	8%	40	Variable	

Notes: 1. The 8 percent cost of capital is in the middle of the range for an average Default Investor Owned Utility and a Merchant plant. (CEC 2009 Table 18 (p. 51))

2. O&M costs, base case, assume natural gas fuel cost of $5 per million Btu and coal costs of $1.38 per million Btu, as per the advice of the Advisory Board of this project. The nuclear fuel cost of $7 per MWh is about the present industry average. The non-fuel nuclear O&M cost for the base case is assumed at $13 (and $10 for the low case). For other O&M costs, the Energy Information Administration's Annual Energy Outlook input data and National Renewable Energy Laboratory data were consulted. (NREL 2008, p. 28 (for wind), EIA 2010a (levelized cost section—all types), Stoddard et al. 2006 Table 5-3 (for CSP), and CEC 2009, all types)

2. CAES: Heat rate = 4,500 Btu/kWh. Non-fuel O&M costs vary by component and are a few dollars per MWh. Total O&M costs, including fuel, are shown here; fuel costs are also separately shown.

3. The natural gas cost in the base case is $5 per million Btu and the heat rate used is 6,500 Btu/kWh (52.5 percent efficiency) for new plants. GE advertises new natural gas combined cycle power plants as having 60 percent efficiency, which gives a heat rate of 5,690 Btu/kWh.[83] However, there was no readily available installed cost estimate for these plants and hence the higher heat rate was used in the estimates in this report.

4. Solar and wind: Capacity factors are for the combination of sites selected. For CSP, the value used is near the upper end of the capacity factors estimated for single axis dry-cooled parabolic trough CSP plants in UREZ II (UREZ

[80] FPL 2007, p. 250 of the 251 page pdf file

[81] Hamilton and Caputo 2009

[82] EPRI-DOE 2004

[83] GE Energy website at http://www.gepower.com/prod_serv/products/gas_turbines_cc/en/h_system/index.htm, viewed on November 30, 2010.

2010, p. 4-4). For wind, the capacity factor used is in the middle of values cited in UREZ I 2008, Table 7, for sites with winds averaging 7 meters per second or more.
5. For technologies with a lifetime of less than 40 years, the present value of a replacement prorated for the remaining years is added to the capital cost. For example, the expander cost of $400 per kW is increased by $56. The present value of $400 invested 25 years hence, discounted at 6 percent is $93.20. But this has a life of 25 additional years, or 10 years beyond the 40 year reference time. So only (15/40)*93.20 = $55.92 is added to the capital cost of the expander. A similar calculation is done for other combined cycle, wind, and concentrating solar power plants, as well as the compressor part of the CAES.
6. Combined cycle natural gas plants are used in a baseload mode in the three renewable scenarios at 80 percent capacity factor and in the intermediate load mode in the Nuclear/CCS scenario at 35 percent capacity factor. The capital charges are adjusted accordingly. For simplicity, total O&M costs are not changed since they are dominated by fuel costs in both cases.

The levelized cost results of the above parameters and per unit costs are shown in Figure VI-1. The levelized cost of coal with CCS is assumed to be the same as nuclear. The cost of nuclear in the base case in this study works out to $150 per MWh. This is about the same as coal with CCS and implies a cost of about $80 per MWh for the carbon capture and storage portion of the plant. The Interagency Task Force on Carbon Capture and Storage also estimates the cost of coal with CCS as $150 per MWh for one of the principal technologies that would be used.[84] An assumption that nuclear and coal with CCS represent about the same costs is therefore reasonable, though both costs have considerable (and different) uncertainties. For natural gas combined cycle plants with CCS, $44 per MWh is added for the CCS part.[85] Wind and CSP costs do not include storage, which is separately taken into account when designing the overall system and estimating its costs. CAES costs are about $30 per MWh but will vary according to the specific level of storage in relation to other generation elements.

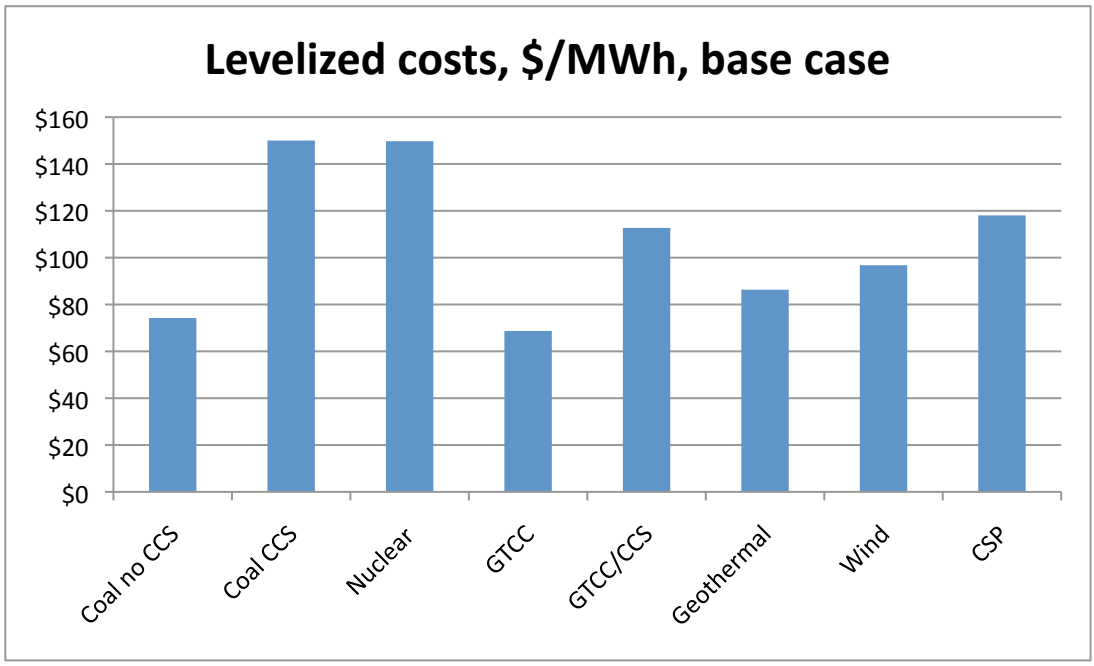

Figure VI-1. Levelized costs of generation technologies used in this report. GTCC stands for a combined cycle natural gas turbine plant. Base case costs are those calculated for the parameters catalogued in this section.

[84] Interagency Task Force 2010
[85] Interagency Task Force 2010 Figure A-9

The demographic, economic, and reference electricity sector parameters used for the calculations are shown in Table VI-3. A key parameter is the relationship of electricity growth to economic growth. In recent years (pre-recession, 2000-2007), this ratio has averaged 0.53. Further, as discussed in Chapter IV, the trend since 2007 has been for this ratio to continue to decline. However, as discussed in more detail there, the results are broadly in line with typical national projections, with the exception that Utah's population is projected to grow about one percent faster than the national rate, with a correspondingly higher economic (and electricity) growth rate.

Table VI-3: Demographic, economic, and electricity sector parameters for the scenarios

Average electricity growth BAU	1.91%
Assumed BAU ratio electricity to economic growth	0.53
Implicit economic growth rate	3.61%
Average population growth rate	1.81%
Per person economic growth rate	1.80%
Size of economy in 2050 relative to 2010	4.12
Utah GDP in 2010, $	$111,000,000,000
Utah GDP in 2050, $	$457,796,169,539
Utah population, 2010	2,927,643
Utah population, 2050	5,989,089
PacifiCorp electricity and economy fraction in Utah	80%
GDP per person in 2010, $	$37,002
GDP per person in 2050, $	$76,438
PacifiCorp generation cost per MWh in 2010 (Note 3)	$41.19
PacifiCorp total generation cost, 2010 (estimated)	$1,000,698,611
2010 generation cost as % of GDP	1.13%
2010 households	958,165
2050 households	2,200,285
2010 generation cost per person (all sectors)	$342

Sources: State of Utah population projections and see notes.

Notes: 1. The ratio of 0.53 of electricity growth rate to economic growth rate is based on the 2000 to 2007 historical rate. This may overestimate demand relative to economic growth since the trend has been for this ratio to decline.

2. The generation cost per person is NOT the annual individual direct cost of residential electricty. Rather, it represents the total electricity generation expenditures per person for all sectors in Utah—residential, commercial, industrial, and agricultural. In other words, it represents direct personal expenditures on electricity as well as indirect expenditures in other sectors.

3. Generation cost of $41.19 per MWh for 2009 was provided by PacifiCorp, personal communication with Arjun Makhijani, 6 December 2010. This value is assumed constant for existing generation for the BAU scenario and for other scenarios until 2033 (inclusive), when all existing coal plants are retired in these scenarios. This means that we assume no new investments in existing plants, though some may be planned, for instance for pollution control. For non-BAU scenarios during 2034 to 2050, a value is derived using a heat rate of 9,000 Btu for the mix of remaining natural gas generating stations, using the prices of gas as recommended by the Board ($3 to $10), with a base case value of $5 per million Btu, and a $10 per MWh non-fuel O&M cost. The results for 2050 are not sensitive to these assumptions.

C. Cost results

We examine costs in two ways: the total generation costs as well as costs per person. The generation cost per person is NOT the annual individual direct cost of residential electricity. Rather, it represents the total electricity generation expenditures per person for all sectors in Utah—residential, commercial, industrial, and agricultural. In other words, it represents direct personal expenditures on electricity as well as indirect expenditures in other sectors. Also, in all cases, transmission and distribution costs are not included because this study is oriented to comparing various systems of supply and the associated costs of reducing CO_2 in the electricity system. We can also compute costs per MWh in the various generation scenarios. The costs per MWh can be computed in two ways. We compute generation costs—that is, costs per MWh for electricity actually generated, which varies from one scenario to the next. We can also compute the cost of electricity services per MWh by adding efficiency costs to generation costs and using the generation in the BAU scenario as the denominator. This provides an apples-to-apples view of the scenarios, since the overall cost of providing cooling, lighting, and common chores, such as dishwashing, is taken into account in each case and the amount of services are the same across scenarios.

Figure VI-2 shows the total cost of generation in all scenarios from the year 2010 to 2050. In all cases, the cost increases—least in the BAU scenario and most in the eUtah scenario. The lowest cost in any carbon reduction scenario is the Renewables/Natural Gas scenario. The highest cost among all the scenarios is the eUtah scenario. The renewable scenarios' higher costs is, in part, attributable to signficant amounts of spilled energy. The cost of the spilled energy, using the levelized cost of solar and wind, is shown in Figure VI-2 as well. This issue, of spilled energy cost, is discussed further in Chapter VII.

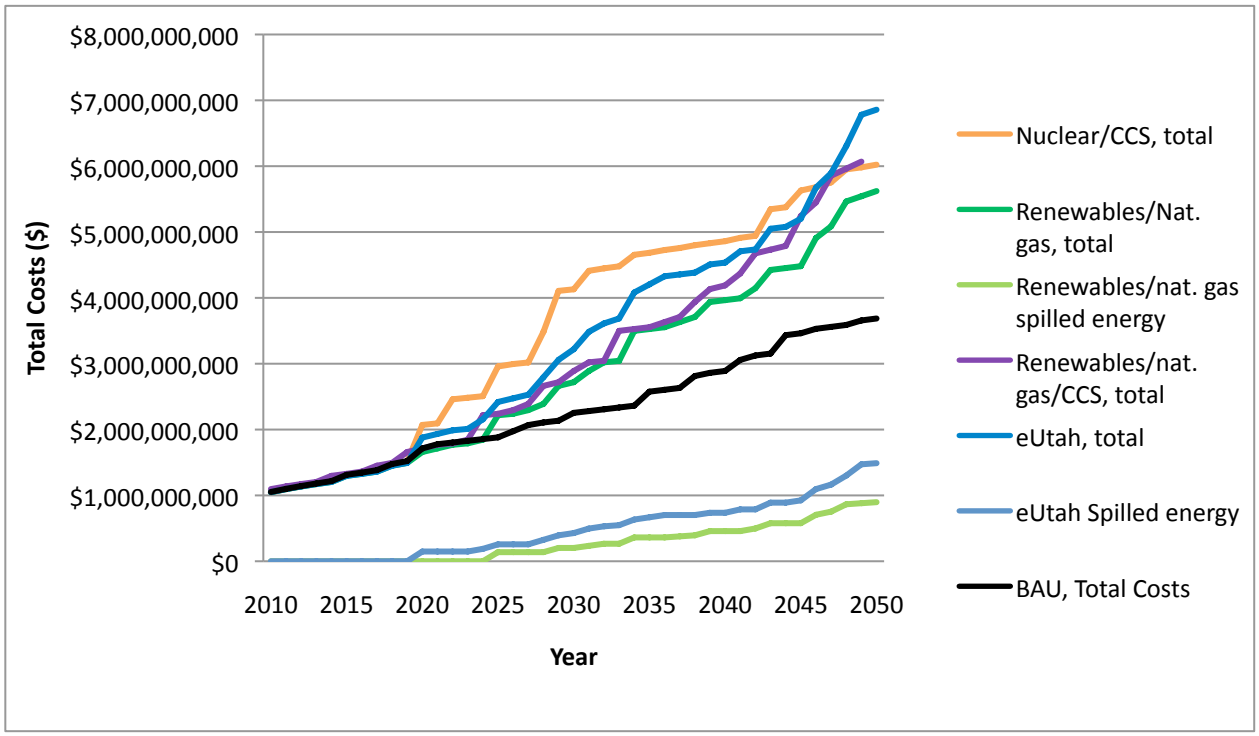

Figure VI-2: Total cost of generation, 2010-2050 in five scenarios, as well as the cost of spilled energy in the renewable scenarios (Renewables/Natural Gas and eUtah)

Figure VI-3 shows the costs per household for residential electricity generation in the year 2050. Note that this is just the generation portion of the electricity cost and does not include transmission and distribution charges. This bar chart assumes that residential electricity consumption in Utah will remain at about 31 percent of the total, as it was in 2008.[86] The cost differences between 2010 and 2050 are also shown.

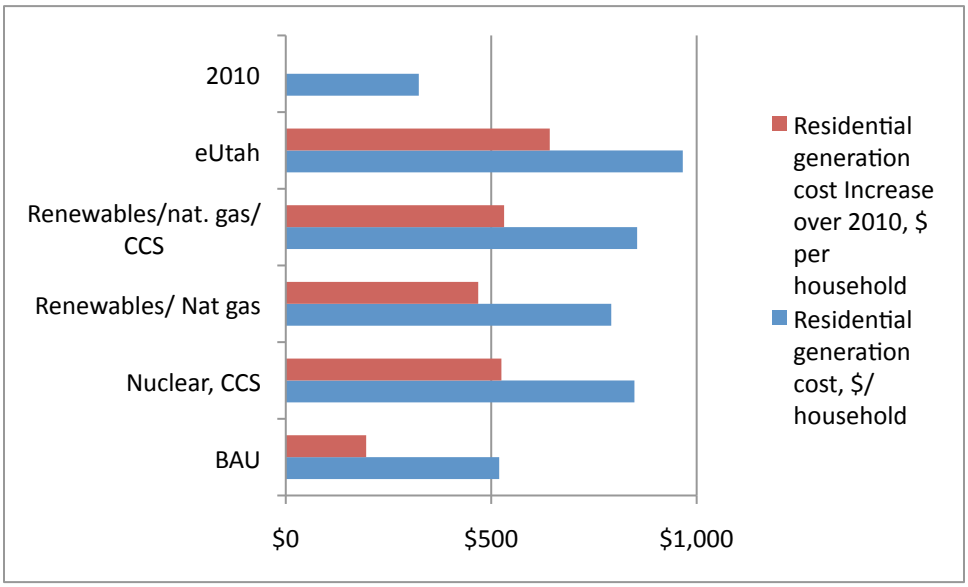

Figure VI-3: Residential electricity costs per household, 2050, with the 2010 cost shown for reference

The cost of residential electricity generation in the year 2050 per person is shown in Figure VI-4, with the 2010 value shown for reference. It shows that an 80 percent reduction in CO_2 emissions can be accomplished with an increase in residential electricity generation cost of about $185 per person per year (Renewables/Natural Gas scenario) relative to 2010 in an economy that would have a per person GDP grow from about $37,000 in 2010 to more than $76,000 in 2050, all in constant 2010 dollars. Moreover, as is discussed in detail below, the renewable scenarios in this study are not optimized, in that the lowest cost mix of consumer side and centralized generation side of investments has not been determined. For example there is nearly $900 million dollars of spilled energy in the Renewables/Natural Gas scenario in the year 2050. This is about $150 per person per year, almost one-third of which can be attributed to the increase in residential cost per person.

[86] EIA 2010c p. 269

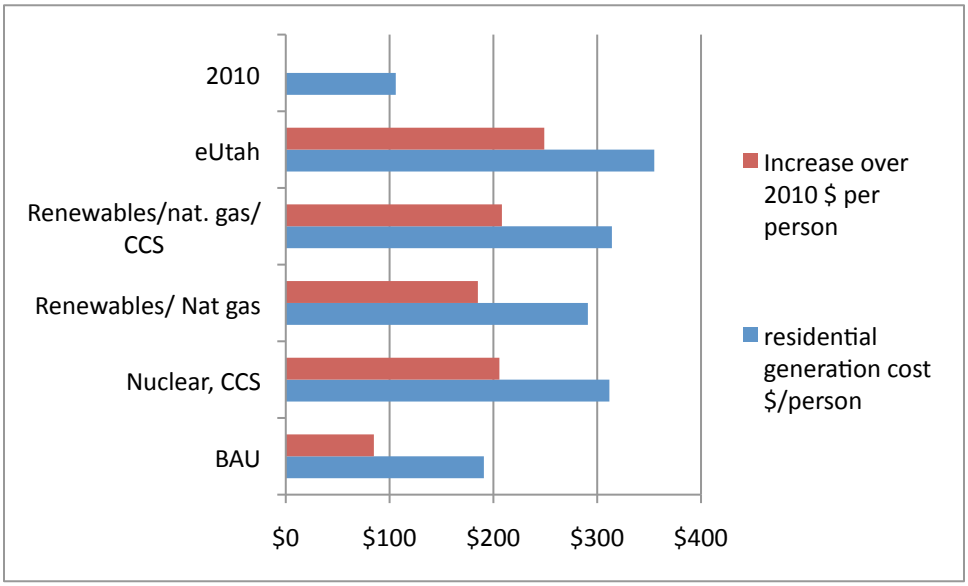

Figure VI-4: Residential electricity generation cost per person, 2050, with the 2010 cost shown for reference.

The cost of electricity generation per person for all sectors of the Utah economy in 2050 is shown as a bar chart in Figure VI-5. Note that this is quite different from Figure VI-4, in which the cost for only the residential portion of electricity use is shown. The cost in the year 2010 is shown as a reference point. It is clear the costs in all cases rise and that costs in the cases of large CO_2 reductions are considerably higher, by roughly a factor of 3 compared to 2010, with a range of 2.75 (Renewables/Natural Gas) to 3.35 (eUtah). However, as discussed below, the cost as a fraction of economic activity does not increase very much, since the additional electricity use produces a considerably larger economic growth.

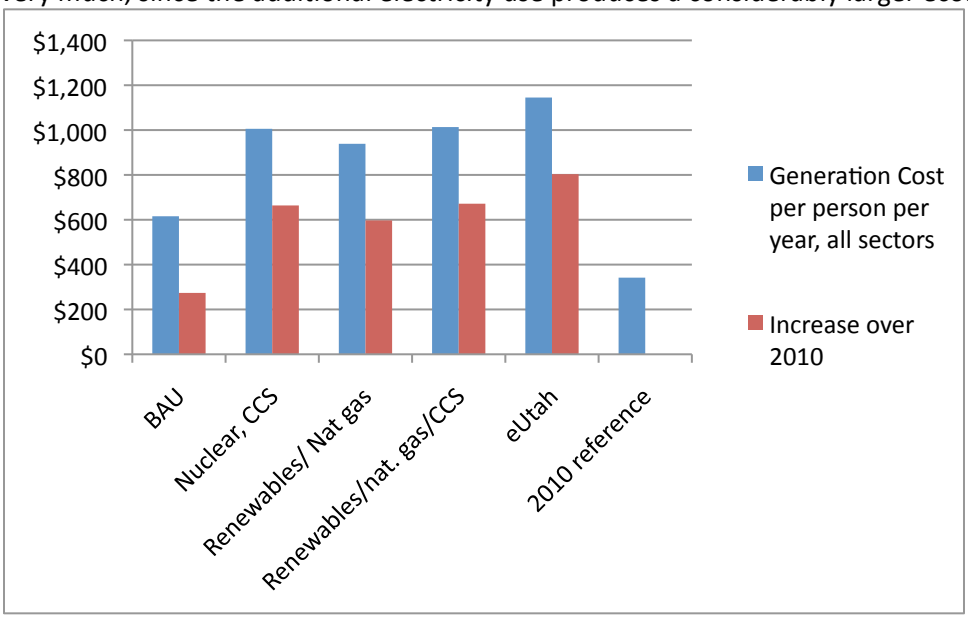

Figure VI-5: Costs of electricity generation per person, 2050, for all sectors of the Utah economy, with the 2010 cost shown for reference

Within the framework of this study, the added costs can be considered as costs of reducing carbon emissions. This actually overstates the costs of emissions reductions, because it ignores a number of collateral benefits, such as reduction in water use in the renewable scenarios and health benefits from signficant reduction in pollutants associated with coal and, to a much lesser extent, natural gas-fired power plants.

Figure VI-6 shows the cost per MWh of generation and electricity services in the year 2050. As explained in Chapter IV, the cost of generation per MWh is simply the total generation cost divided by the electricity generated in that scenario. The cost per MWh of electricity services adds the cost of efficiency to the generation cost, but the denominator is the total electricity services as represented by the generation in the BAU scenario. Since efficiency is on average cheaper than BAU scenario generation, taking efficiency into account lowers the cost per MWh. In effect, it illustrates the effect on electricity bills of adding efficiency to the way in which electricity services are provided.

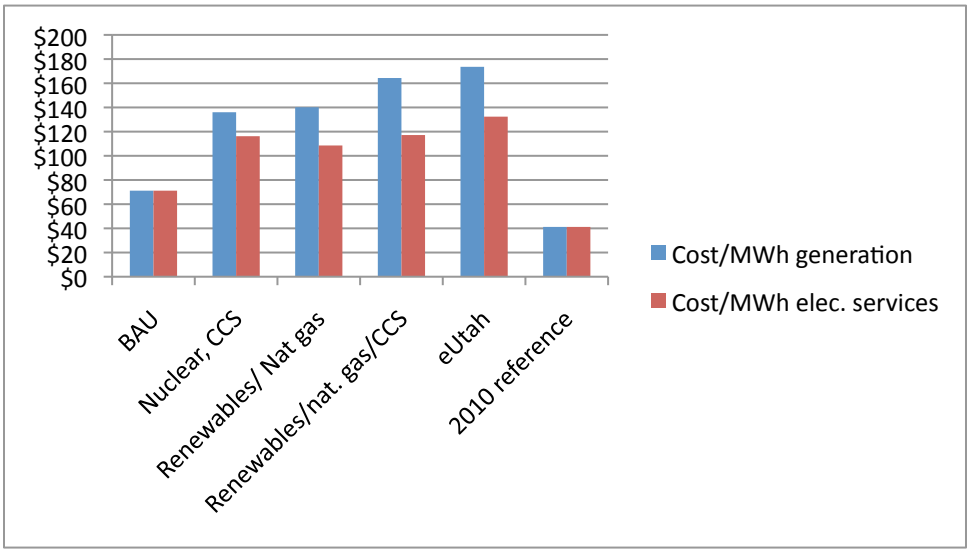

Figure VI-6: Cost per MWh of electricity generation and electricity services in 2050, with the 2010 cost shown for reference

Figure VI-7 shows the CO_2 emissions from 2010 to 2050 in the various scenarios. As is evident, the BAU scenario has increasing emissions, since it is a coal-to-coal scenario, meaning that retired coal-fired power plants are replaced by new ones. Emissions grow from about 20 million metric tons in 2010 to about 35 million metric tons in 2050.[87] The curves are rather jagged partly due to the fact that generation is added in chunks and partly due to an artifact of the construction of the scenarios. Specifically, the capacity factor of each new generation element added is kept constant throughout the period 2020 to 2050. This means that existing resources are treated as a residual source of generation, subject ,of course, to the constraints on retirement, discussed in Chapter V.

[87] Figures are rounded in the discussion in the text for ease of reading and comparison. The tables and charts show the actual values as calculated.

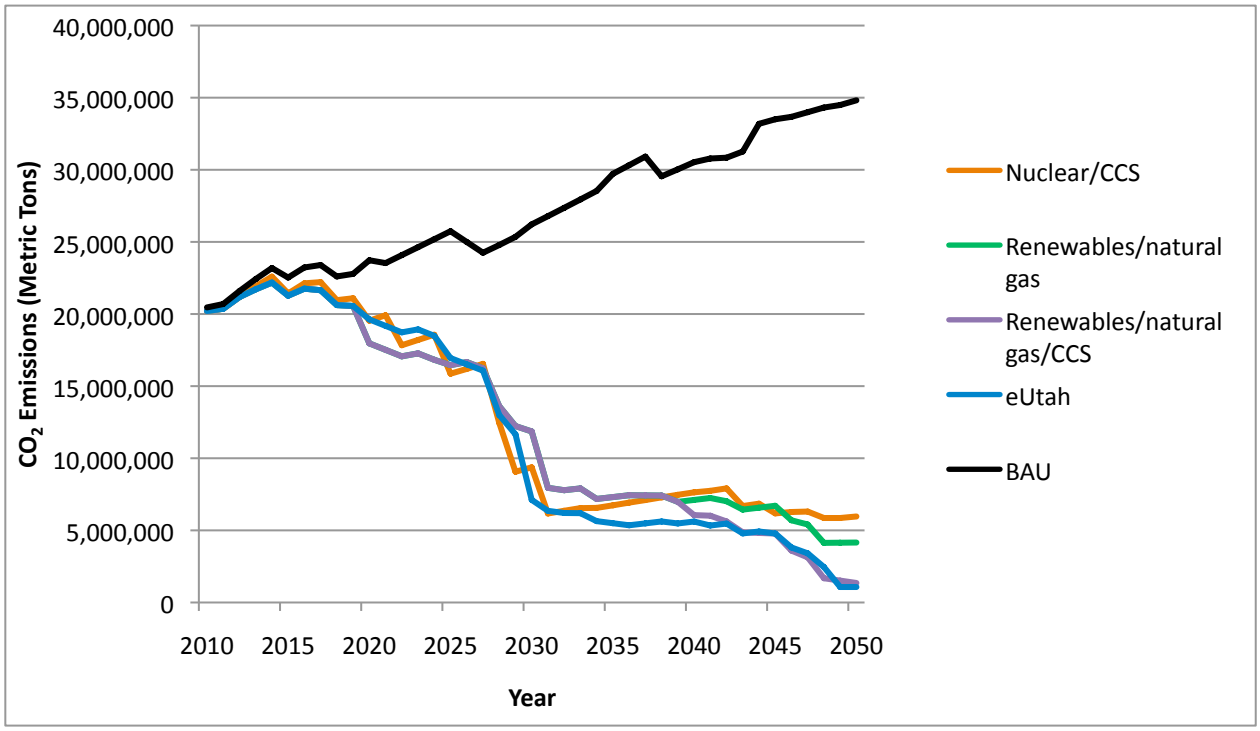

Figure VI-7: CO_2 emissions in the various scenarios. The emissions increase in the BAU scenario, is a result of the fact that carbon is not constrained as part of the BAU scenario design. The jagged curves result, in part, from varying amounts of generation from existing capacity (see text).

Table VI-4 summarizes the most important results in using the base case fuel and capital cost values for various generation elements. As can be seen, CO_2 emissions are 83 percent lower than BAU in the Nuclear/CCS scenario, 88 percent lower in the Renewables/Natural Gas scenario, and over 95 percent lower in the other Renewables/Natural Gas/CCS and eUtah scenarios. Relative to 2010, CO_2 emissions reductions are between about 70 percent and 95 percent in the four reduction scenarios. There is an increase of CO_2 emissions by 70 percent relative to 2010 in the BAU scenario. Per person CO_2 emissions vary from a high of 5,800 kilograms in 2050 in the BAU scenario to a low of 179 kilograms in the eUtah scenario.

Table VI-4. Economic Results. Costs of electricity and CO_2 reductions in 2050 across five scenarios, including base case fuel and capital cost parameters

	BAU	Nuclear, CCS	Renewables/ Nat gas	Renewables/nat. gas/CCS	eUtah
Electricity generation cost in 2050 $	$3,686,778,993	$6,022,751,956	$5,622,315,397	$6,069,400,237	$6,858,037,925
Generation cost per person per year	$616	$1,006	$939	$1,013	$1,145
Electricity cost as % of Utah GDP in 2050	**1.01%**	**1.64%**	**1.54%**	**1.66%**	**1.87%**
Excess cost relative to BAU	0	$2,335,972,963	$1,935,536,404	$2,382,621,244	$3,171,258,932
CO_2 emissions, mt/ year	34,816,325	5,962,996	4,156,520	1,353,149	1,002,962
Percent CO_2 reductions relative to 2050 BAU emissions	0	83%	88%	96%	97%
Percent CO_2 reductions relative to BAU in 2010 CO2 emissions	-70%	71%	80%	93%	95%
CO_2 emissions per person, kg/year	5,813	996	694	226	167
CO_2 emissions reduction cost $/mt	N/A	$81	$63	$71	$94
CO_2 risk in 2050 @$50 per ton relative to eUtah	$1,740,816,272	$298,149,819	$207,825,995	$67,657,446	$50,148,104
Cost including CO_2 risk	$5,427,595,265	$6,320,901,775	$5,830,141,391	$6,137,057,683	$6,908,186,030
Cost difference/person, 2050, relative to BAU, with $50/mt CO_2 cost	0	$149	$67	$118	$247
Residential electricity cost $ per household	$519	$849	$792	$855	$966
Cost difference per person in 2050, relative to BAU, with zero CO_2 cost	$0	$390	$323	$398	$530

While the cost picture does not look rosy for reducing carbon when compared to present day electricity generation costs, it must be remembered that the increased cost is in the context of a growing economy and increasing use of the services that electricity provides. Hence, besides total cost, which is, of course, important, the fraction of gross domestic product that goes into electricity is also relevant.

Figure VI-8 shows the percentage of Utah GDP that would be used for electricity generation in the various scenarios. The 2010 value is shown in the bar graph for reference.

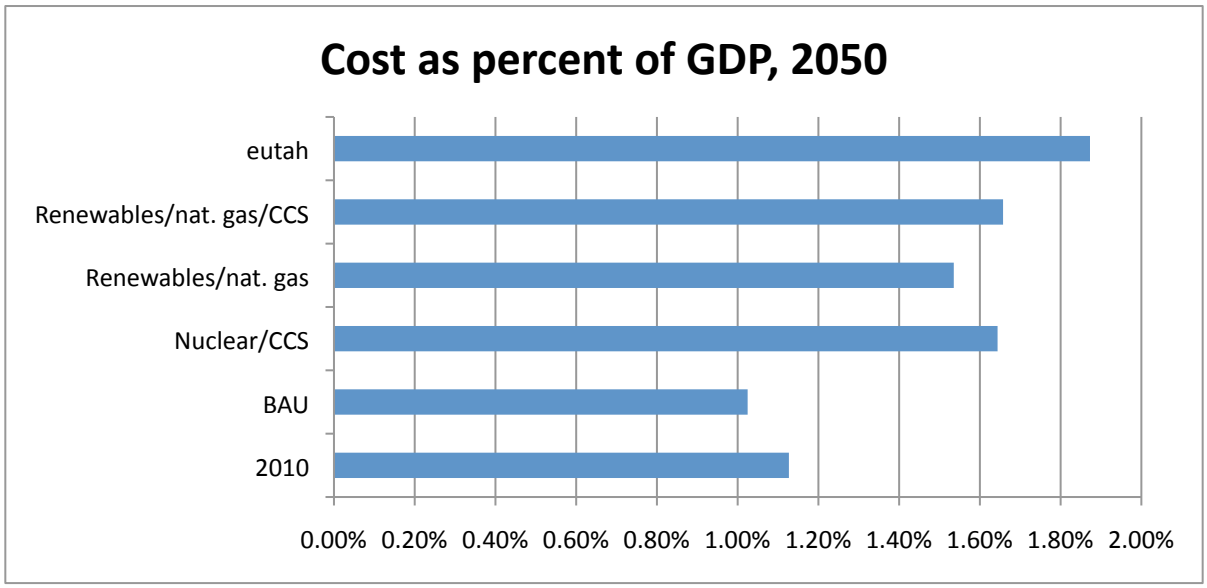

Figure VI-8: Percent of Utah GDP devoted to electricity generation in 2050, with the 2010 value shown for reference.

This picture shows that it would be affordable in a growing economy to transition to a mainly renewable electricity system (the Renewables/Natural Gas scenario) while keeping the expenditures on electricity generation at about 1.5 percent. But, the BAU scenario would reduce the percentage of GDP devoted to generation from about 1.1 percent to about 1 percent. Despite the fact that the BAU scenario appears, in the figure above, to be the most affordable in a growing economy, there are two broad and important reasons, which are not reflected in the figure above, to consider an all-renewable scenario.

First, the quality of the product offered in terms of collateral benefits such as lower air pollution and reduced water use are substantial, even if the former is difficult to quantify (see below). An analogy might be made to cars. The cars of the 1960s worked well to transport people from one spot to another but they were polluting and much less safe than the vehicles of today. Transitioning to cars with air bags and emission control systems adds to cost, but it also adds to value.

Second, it is critical to remember that there is a very real risk that carbon emissions will not remain cost-free. This is covered in the next section. As a prefatory remark, we note that the carbon emissions cost risk and low natural gas prices are the main reasons that many utilities are investing in natural gas combined cycle plants and wind rather than coal. This is just the course recommended here so far as centralized generation plants are concerned.

D. CO_2 related risks

While the BAU scenario is the lowest cost when the CO_2 emission price is set at zero, the picture would be quite different, if a cost is imputed to the CO_2 emissions. Figure VI-9 shows the carbon emissions reductions relative to 2010. The negative value for the BAU scenario means an increase in emissions. A

different picture, from 2010 to 2050 of emissions (rather than reductions) was discussed above—see Figure VI-7.

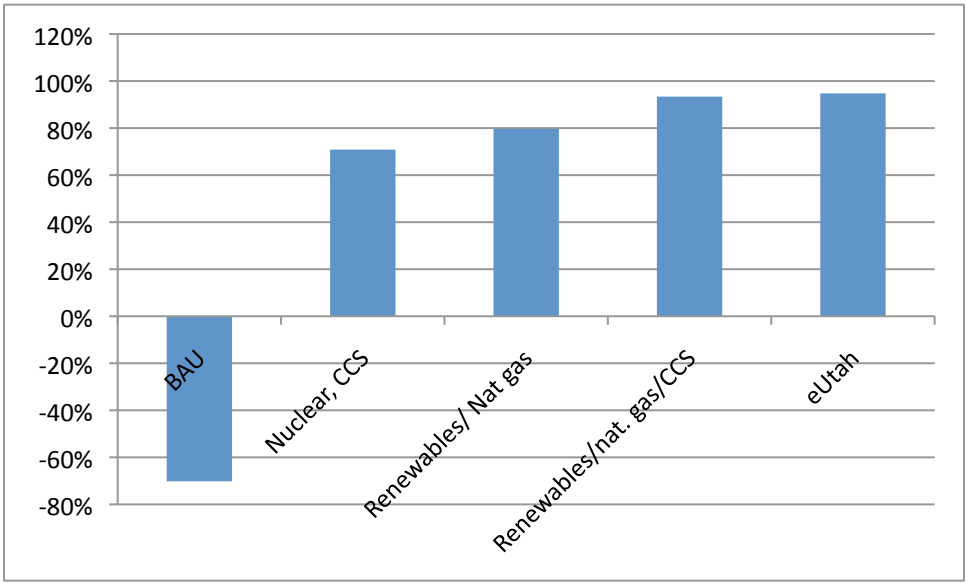

Figure VI-9: CO_2 emissions reductions in the year 2050 relative to 2010 in the various scenarios. The negative number for BAU represents an increase in emissions.

One way to estimate the risk is to assume a CO_2 price (or tax) that would be prevalent in 2050 by looking at the costs of CO_2 reductions in the scenarios other than BAU. The cost of reductions of CO_2 emissionsis between $63 to $94 per metric ton, using base case economic parameters, as can be seen from Table VI-4 above. As we will see in the sensitivity calculations, the full range of costs, once the uncertainties in fuel and capital costs are taken into account is $40 to $137 per metric ton. The average of the base case costs is about $75 per metric ton. PacifiCorp uses four values of a carbon tax in its planning: $0, $45, $70, and $100 per metric ton of CO_2.[88] The average of these values is $54. We have rounded this figure down to $50 to do the risk estimates shown at the bottom of Table VI-4 above.

If a cost of $50 is added to CO_2 emissions in each scenario, the costs of the BAU scenario increase greatly, while the others increase moderately to very little depending on the level of CO_2 reductions modeled in that scenario. At $50 per metric ton the BAU scenario is still the lowest cost, but only marginally (and with all other benefits of CO_2 reduction, such as water and health, ignored). Annual per person cost increases relative to BAU to reduce CO_2 emissions by 80 percent below 2010 emissions are only $67 in the Renewables/Natural Gas scenario, which is the lowest cost of the carbon reduction cases.

Of course, the CO_2 emissions cost of $50 per metric ton is unlikely to arise suddenly in the year 2050. A strategy that aims to simply rely on fossil fuels, especially coal, will incur risks for much or most of the 2010 to 2050 period. We can calculate the present value in the year 2010 of future CO_2 risks at various CO_2 emission prices (or tax levels). We assume a CO_2 emissions cost of zero between 2010 and 2020, and the four levels of cost modeled by PacifiCorp in its 2008 IRP. Figure VI-10 shows the resulting estimate of risk. Of course, it would remain zero if there is no price attached to CO_2 emissions. But even at the lower end of price assumptions, the cumulative present value of the cost of not reducing CO_2

[88] PacifiCorp Case Definitions 2008

emissions after 2020 rises to about $10 billion at $45 per metric ton to $22 billion at $100 per metric ton.[89]

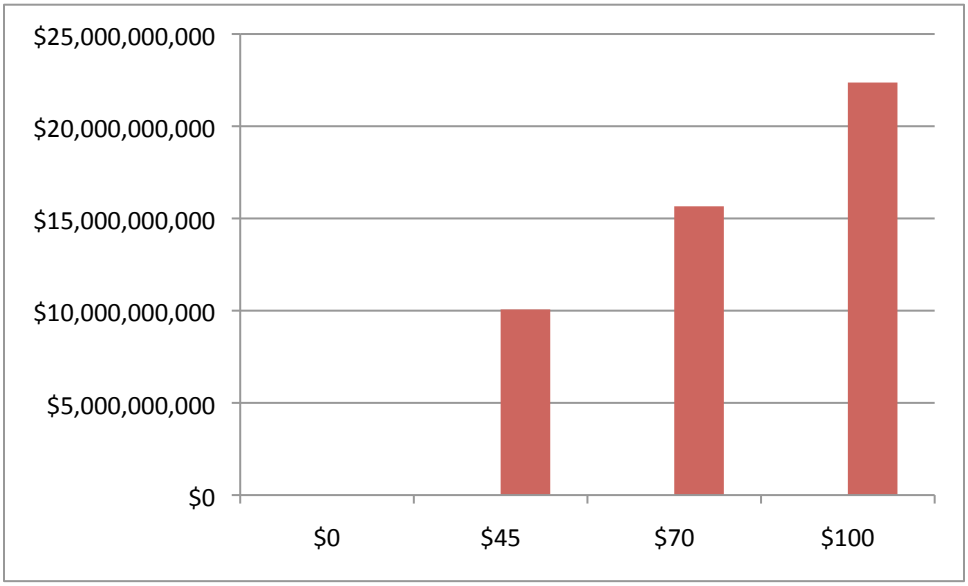

Figure VI-10: Present value in 2010 of carbon costs incurred over the period 2020 to 2050 at various levels of carbon tax

The CO_2 emissions reduction costs are not constant over time, but vary somewhat with the scenario. This variation is larger in the case of the Nuclear/CCS scenario, since investments are more lumpy—that is, baseload plant sizes are 300 MW megawatts or larger.

E. Spilled energy

In Chapter V we discussed the problem of spilled energy that arises in the three renewable energy scenarios due to the centralized nature of the generation, the single storage system, and the lack of a distributed intelligent grid that could greatly reduce this problem. Estimating the increased costs due to spilled energy allows us to estimate the maximum investments that could be made on a distributed smart grid in which many loads were responsive to the state of generation and storage and where local storage designed for specific loads was associated with local generation systems, reducing the need both for central station generation and storage. We focus this discussion on the eUtah scenario, since the problem of spilled energy is the most severe in that case. In 2050 in the eUtah scenario, the cost of spilled energy, estmated at the average levelized cost of solar and wind, is as high as $1.5 billion, starting from zero in 2019.

The present value in 2010 of spilled energy, which grows from 2020 to 2050 as shown in Figure VI-11, at a discount rate of 6 percent, is about $3.7 billion, or almost $1,300 per person in Utah in 2010. This gives an indication of the amount of investment that could be made to eliminate spilled energy. If some of that investment actually were in energy efficiency directed to shaping the load curve not only daily but seasonally, this level of investment would still be profitable (rather than netting out at zero) because

[89] The discount rate used is 6 percent, the same value used for the levelized cost calculations.

the total amount of central station generation and storage would be reduced relative to the eUtah scenario.

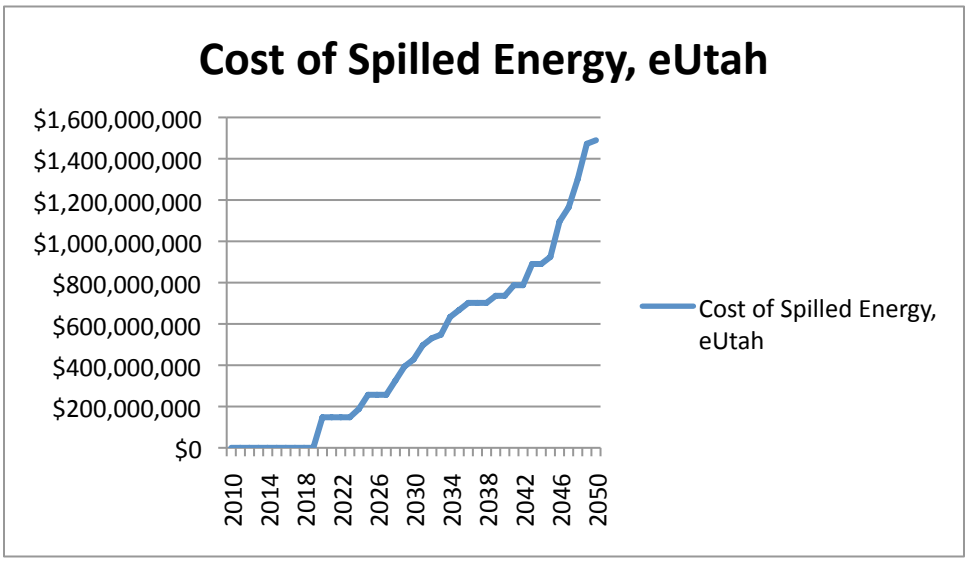

Figure VI-11: Cost of spilled energy in the eUtah scenario from 2010 to 2050, valued at the average cost of solar and wind energy generation

As we discussed in Chapter V, one of the difficulties of addressing spilled energy is because it is heavily seasonal. Figure VI-12 illustrates this problem in a different way. The expander (turbine-generator associated with the compressed air energy storage) is most fully used just for a few hours in the winter, shown in hand-drawn bubbles, in the late evening and night, when there is no solar energy output and the wind has fallen to very low levels. Figure VI-12 illustrates the transformed nature of the peak load problem in a solar/wind/storage centralized generation system. The old summer peak load problem has not quite disappeared but it is not the one that dominates the need for marginal investments in capacity. The need for marginal investments in capacity is, rather, dominated by the relational system peak, which occurs in the winter.

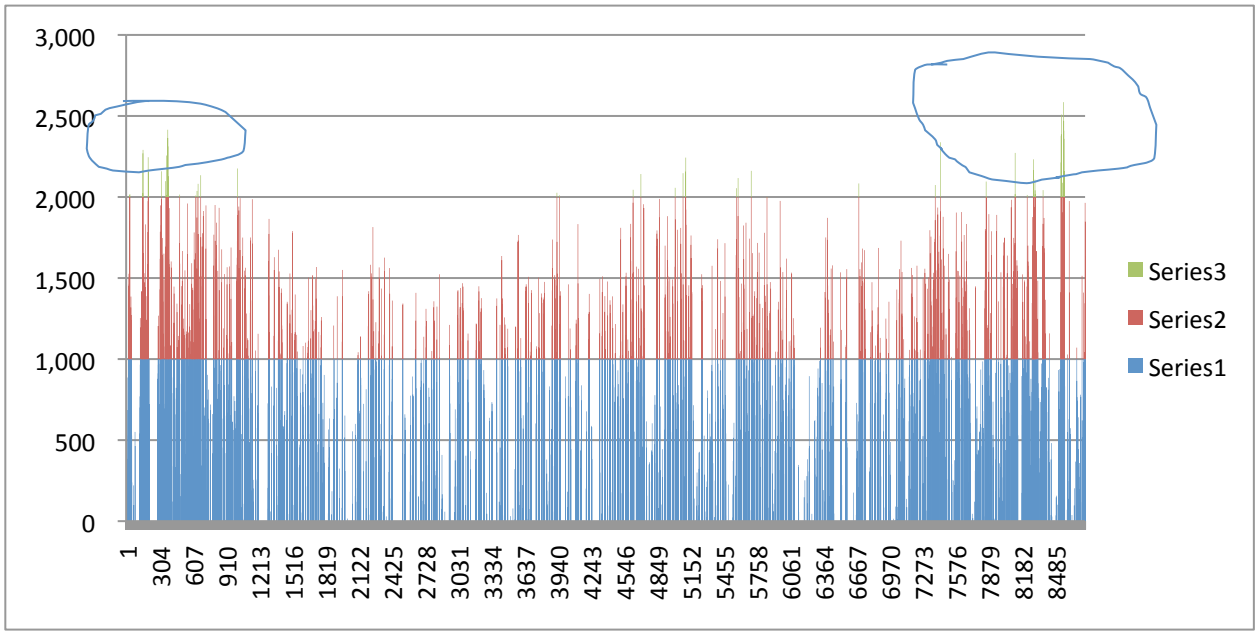

Figure VI-12: Use of expander capacity to generate electricity from storage in the reference year in the eUtah scenario. Series 1: the 1st 1,000 MW of expander, series 2, the next 1,000 MW; series 3 the final tranche. The horizontal axis is hours of the year, starting with the midnight hour on Janurary 1.

The fact that the relational system peak is seasonal yields insights into the areas where investment would have the biggest payoff. For instance, lighting is a bigger load in the winter—and especially in the hours that drive the peak installed capacity. Lighting efficiency improvements are already well-known to be economical, but they would be even more so, when the problem of spilled energy is taken into account, since winter lighting electricity use is larger than in the other seasons. Similarly, investments in improving the efficiency of blowers and pumps used in heating systems would yield a disproportionate return. District heating systems and combined heat and power systems, designed to alleviate relational system peaks may be other options. The persistence of summer utilization of most of expander capacity at some times indicates that improvements in insulation as well as in air-conditioning systems could improve system economics. Overall Figure VI-12 illustrates the complexity of the problem of the relational system peak, especially when one takes into account the potential variation of the duration and size of the peak from year to year due to fluctuations in solar and wind energy supply.

The problem of spilled energy could also be alleviated by careful choice of solar and wind locations. For instance, wind generation with higher capacity factor in the winter would alleviate the problem of spilled energy considerably in the eUtah scenario. However, this may require the use of out-of-state resources. This is dicussed in Chapter VII.

F. Sensitivity analysis

Here we vary some of the cost parameters used in the base case. When no variation is mentioned the parameters are kept the same as in the base case, which has been described in detail above. Six cases were tested:

1. High fossil fuel and nuclear O&M costs: natural gas = $10 per million Btu, coal = $3 per million Btu, nuclear fuel = $17 per MWh and nuclear O&M = $27 per MWh. The high nuclear fuel and

O&M cost is taken from the Keystone Joint Fact Finding, which had the participation of the nuclear industry as well as other experts.[90]

2. Low fossil fuel and nuclear O&M: natural gas = $3 per million Btu, coal = $1 per million Btu, nuclear fuel = $7 per MWh and nuclear O&M = $10 per MWh.
3. High nuclear capital cost and risk: Capital cost = $10,000/kW (all-in, including allowance for funds during construction) and cost of capital = 14 percent.
4. Low nuclear capital cost: $7,000/kW and 10 percent cost of capital.
5. High solar and wind cost; concentrating solar power cost = $3,000/kW and wind = $2,500/kW.
6. Low solar and wind capital cost: concentrating solar power cost = $1,500/kW and wind = $1,500/kW.

As noted above, we have not used the lowest values for capital cost in the renewable case. Capacity factor is not varied and geothermal costs are not varied. We assumed the coal with CCS costs will approximately track nuclear costs (both low and high). Tables VI-5 though VI-10 show the results of the sensitivity analysis.

Table VI-5: Sensitivy analysis in the high fossil fuel and nuclear O&M case

	BAU	Nuclear, CCS	Renewables/ Nat gas	Renewables/nat. gas/CCS	eUtah
Electricity generation cost in 2050 $	$4,796,270,903	$7,414,317,523	$6,181,530,077	$6,628,614,917	$7,023,172,637
Cost per person per year	$801	$1,238	$1,032	$1,107	$1,173
Electricity Cost as % of Utah GDP in 2050	**1.31%**	**2.02%**	**1.69%**	**1.81%**	**1.92%**
Excess cost relative to BAU	0	$2,618,046,620	$1,385,259,174	$1,832,344,014	$2,226,901,734
CO_2 emissions, mt/ year	34,816,325	5,962,996	4,156,520	1,353,149	1,002,962
CO_2 emissions reduction cost $/mt	$0	$91	$45	$55	$66
CO_2 risk in 2050 @$50 per ton relative to eUtah	$1,740,816,272	$298,149,819	$207,825,995	$67,657,446	$50,148,104
Cost including CO_2 risk	$6,537,087,175	$7,712,467,342	$6,389,356,071	$6,696,272,363	$7,073,320,741
Cost difference per person in 2050, relative to BAU, with $50/mt CO_2 cost	$0	$196	($25)	$27	$90

[90] Keystone 2007 p. 11

Table VI-6: Sensitivy analysis in the low fossil fuel and nuclear O&M case

	BAU	Nuclear, CCS	Renewables/ Nat gas	Renewables/nat. gas/CCS	eUtah
Electricity generation cost in 2050 $	$3,342,971,033	$5,743,146,949	$5,398,629,525	$5,845,714,365	$6,791,984,041
Cost per person per year	$558	$959	$901	$976	$1,134
Electricity Cost as % of Utah GDP in 2050	**0.91%**	**1.57%**	**1.47%**	**1.60%**	**1.85%**
Excess cost relative to BAU	0	$2,056,367,957	$1,711,850,532	$2,158,935,373	$3,105,205,048
CO_2 emissions, mt/ year	34,816,325	5,962,996	4,156,520	1,353,149	1,002,962
CO_2 emissions reduction cost $/mt	$0	$83	$67	$75	$102
CO_2 risk in 2050 @$50 per ton relative to eUtah	$1,740,816,272	$298,149,819	$207,825,995	$67,657,446	$50,148,104
Cost including CO_2 risk	$5,083,787,305	$6,041,296,768	$5,606,455,519	$5,913,371,811	$6,842,132,145
Cost difference per person in 2050, relative to BAU, with $50/mt CO_2 cost	$0	$160	$87	$139	$294

Table VI-7: Sensitivy analysis in the high nuclear and coal with CCS capital cost case

	BAU	Nuclear, CCS	Renewables/ Nat gas	Renewables/nat. gas/CCS	eUtah
Electricity generation cost in 2050 $	$3,686,778,993	$7,644,922,903	$5,622,315,397	$6,069,400,237	$6,858,037,925
Cost per person per year	$616	$1,276	$939	$1,013	$1,145
Electricity Cost as % of Utah GDP in 2050	**1.01%**	**2.09%**	**1.54%**	**1.66%**	**1.87%**
Excess cost relative to BAU	0	$3,958,143,910	$1,935,536,404	$2,382,621,244	$3,171,258,932
CO_2 emissions, mt/ year	34,816,325	5,962,996	4,156,520	1,353,149	1,002,962
CO_2 emissions reduction cost $/mt	$0	$137	$63	$71	$94
CO_2 risk in 2050 @$50 per ton relative to eUtah	$1,740,816,272	$298,149,819	$207,825,995	$67,657,446	$50,148,104
Cost including CO_2 risk	$5,427,595,265	$7,943,072,722	$5,830,141,391	$6,137,057,683	$6,908,186,030
Cost difference per person in 2050, relative to BAU, with $50/mt CO_2 cost	$0	$420	$67	$118	$247

Table VI-8: Sensitivy analysis in the low nuclear and coal with CCS capital cost case

	BAU	Nuclear, CCS	Renewables/ Nat gas	Renewables/nat. gas/CCS	eUtah
Electricity generation cost in 2050 $	$3,686,778,993	$4,878,380,805	$5,622,315,397	$6,069,400,237	$6,858,037,925
Cost per person per year	$616	$815	$939	$1,013	$1,145
Electricity Cost as % of Utah GDP in 2050	**1.01%**	**1.33%**	**1.54%**	**1.66%**	**1.87%**
Excess cost relative to BAU	0	$1,191,601,812	$1,935,536,404	$2,382,621,244	$3,171,258,932
CO_2 emissions, mt/ year	34,816,325	5,962,996	4,156,520	1,353,149	1,002,962
CO_2 emissions reduction cost $/mt	**0**	**$41**	**$63**	**$71**	**$94**
CO_2 risk in 2050 @$50 per ton relative to eUtah	$1,740,816,272	$298,149,819	$207,825,995	$67,657,446	$50,148,104
Cost including CO_2 risk	$5,427,595,265	$5,176,530,624	$5,830,141,391	$6,137,057,683	$6,908,186,030
Cost difference per person in 2050, relative to BAU, with $50/mt CO_2 cost	$0	($42)	$67	$118	$247

Table VI-9: Sensitivy analysis in the high solar and wind capital cost case

	BAU	Nuclear, CCS	Renewables/ Nat gas	Renewables/nat. gas/CCS	eUtah
Electricity generation cost in 2050 $	$3,711,555,530	$6,047,528,493	$6,216,174,397	$6,663,259,237	$7,769,947,246
Cost per person per year	$620	$1,010	$1,038	$1,113	$1,297
Electricity Cost as % of Utah GDP in 2050	**1.01%**	**1.65%**	**1.70%**	**1.82%**	**2.12%**
Excess cost relative to BAU	0	$2,335,972,963	$2,529,395,404	$2,976,480,245	$4,083,168,253
CO_2 emissions, mt/ year	34,816,325	5,962,996	4,156,520	1,353,149	1,002,962
CO_2 emissions reduction cost $/mt	**0**	**$81**	**$82**	**$88**	**$120**
CO_2 risk in 2050 @$50 per ton relative to eUtah	$1,740,816,272	$298,149,819	$207,825,995	$67,657,446	$50,148,104
Cost including CO_2 risk	$5,452,371,802	$6,345,678,312	$6,424,000,391	$6,730,916,683	$7,820,095,350
Cost difference per person in 2050, relative to BAU, with $50 per ton CO_2 cost	$0	$149	$162	$213	$395

Table VI-10: Sensitivy analysis in the low solar and wind capital cost case

	BAU	Nuclear, CCS	Renewables/ Nat gas	Renewables/nat. gas/CCS	eUtah
Electricity generation cost in 2050 $	$3,628,967,072	$5,964,940,036	$4,867,921,355	$5,315,006,196	$5,696,301,647
Cost per person per year	$606	$996	$813	$887	$951
Electricity Cost as % of Utah GDP in 2050	**0.99%**	**1.63%**	**1.33%**	**1.45%**	**1.56%**
Excess cost relative to BAU	0	$2,335,972,963	$1,238,954,283	$1,686,039,123	$2,067,334,575
CO_2 emissions, mt/ year	34,816,325	5,962,996	4,156,520	1,353,149	1,002,962
CO_2 emissions reduction cost $/mt	**0**	**$81**	**$40**	**$50**	**$61**
CO_2 risk in 2050 @$50 per ton relative to eUtah	$1,740,816,272	$298,149,819	$207,825,995	$67,657,446	$50,148,104
Cost including CO_2 risk	$5,369,783,344	$6,263,089,855	$5,075,747,350	$5,382,663,641	$5,746,449,752
Cost difference per person in 2050, relative to BAU, with $50/mt CO_2 cost	$0	$149	($49)	$2	$63

The arrays of numbers in Tables VI-5 to VI-10 can be summarized with a few observations:

- The lowest cost scenario for CO_2 reduction costs is the Renewables/Natural Gas scenario for a level of reductions of about 80 percent relative to 2010. The lowest cost for more than 90 percent reductions is to add a carbon capture element to the natural gas combined cycle plants in this scenario.
- If CO_2 costs and risks are ignored, then the BAU, coal-to-coal approach would be the lowest cost. However, such costs and risks cannot be ignored. They are real, and the market is factoring them in even today in the absence of formal federal limits of CO_2 emissions or a CO_2 tax.
- The cost differential between the scenarios becomes rather modest in most cases once a CO_2 cost is factored in. The cost difference per person between the BAU scenario with a $50 CO_2 emissions price (or tax) and the other scenarios are a few tens of dollars per year in most cases, extending to a few hundred dollars in two cases: the high nuclear capital cost case (with base case parameters for BAU) and the high solar and wind capital costs case. In some variations, the BAU costs (with a $50 CO_2 cost per metric ton) are actually higher. When a moderate level of CO_2 emissions cost is added to the BAU scenario, the differences between the BAU scenario and the other scenarios become small in most cases. They are within the expected uncertainties of the fuel and capital cost parameters.
- The cost of spilled energy plays a big role in the eUtah case.
- Generally, nuclear energy has no particular advantage over renewables with natural gas in reducing carbon emissions. In fact, it has a somewhat higher cost, except if nuclear capital and financing costs are assumed to be low and other costs are kept in the base case.

Figure VI-13 summarizes the sensitivity analysis for CO_2 costs.

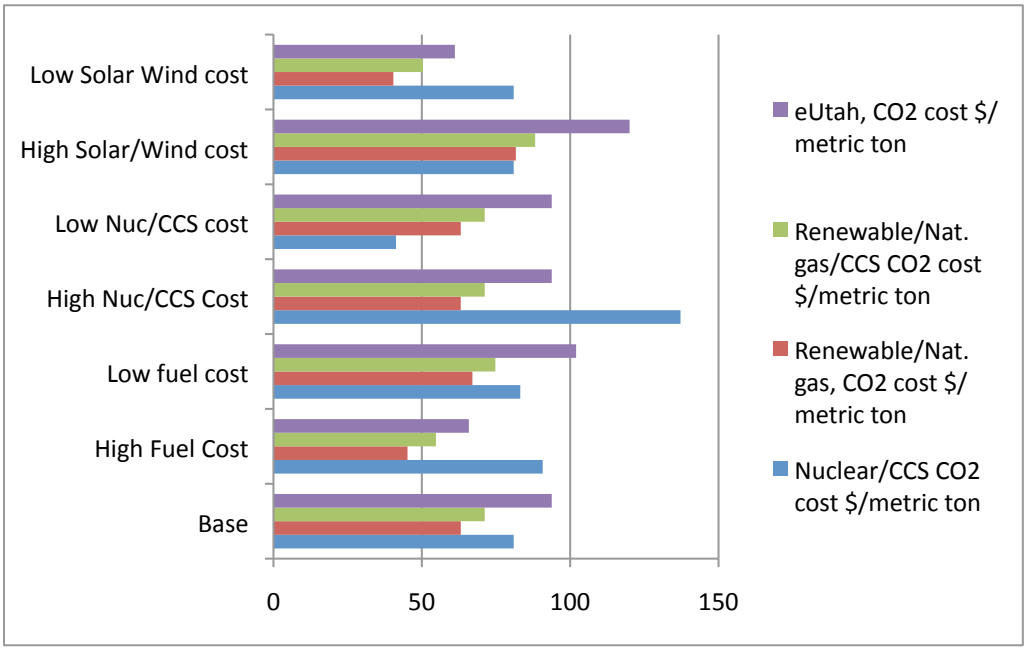

Figure VI-13: CO_2 emissions reduction costs, in dollars per metric ton, shown on the X-axis, under six variations of cost parameters compared to the base case.

G. Interstate trade in renewable energy

In this study we assumed that all renewable resources that are used will be in-state resources. This was partly a matter of convenience and partly to show that the renewable energy potential in Utah is large enough to meet the needs of the state for the foreseeable future. However, the in-state approach results in higher costs than if renewable energy were traded across state lines. Specifically, our estimate of in-state average wind energy costs for the combination of sites considered here is about $97 per MWh. The average capacity factor is 29 percent. Costs go down sharply with increase in capacity factor. The National Renewable Energy Laboratory data indicate an average capacity factor of about 40 percent for wind resources in Wyoming,[91] which would lower costs by about one-fourth to just $73 per MWh. This is comparable to new coal-fired power plants without carbon constraints and to natural gas-fired combined cycle power plants with gas at $5 per million Btu. Moreover, it has none of the risks associated with coal.

Utah could consider exporting solar energy to Wyoming and importing wind energy from there. In any case, most of the area is in the service territory of PacifiCorp, which already relies on Wyoming wind preferentially due to lower cost. The overall cost reduction by swapping Utah wind resources for Wyoming wind resources would be about $530 million dollars per year in the eUtah scenario in 2050, or almost $90 per person per year.

Since solar energy is better matched to demand, storage costs and requirements are reduced when wind and solar are combined. Further, the storage requirements and spilled energy may also be reduced by the higher capacity factor of wind energy in Wyoming. A study looking at the long term wind supply largely from Wyoming and solar mainly from Utah for both states would be beneficial. A very

[91] NREL 2010

substantial reduction in costs (possibly on the order of 10 to 20 percent) would likely be accomplished for all renewable energy scenarios modeled in this study using such a approach.

H. Water

Thermal electrity generation is one of the principal uses of water in the United States.[92] Moreover, unlike much residential water use, a large amout of water is evaporated due to the need for condensing the steam that drives the turbines. This can be done in several ways. Once-through cooling takes in water from a river or lake (or the ocean in some cases). This is heated up by 10 degrees F or more in the condenser and discharged back into the river or lake where some of the water evaporates, cooling the rest. Hundreds of millions of gallons of water are required for a once-through cooling system, but only a small fraction is evaporated. Cooling ponds with a stock of water that is drawn upon from one side of the pond and discharged to another reduce the need for water intake from rivers and lakes. Such ponds require large areas—typically a few thousand acres for a 1,000 megawatt plant, depending on the depth of the pond.

The use of cooling towers is a common method in water scarce areas, since they minimize intake requirements, but evaporation tends to be larger since the cooling is achieved almost completely by this means.

Solar photovoltaics and wind energy use essentially no water by comparison. Concentrating solar power plants that have wet-cooled condensers use more water than coal, natural gas, or nuclear power plants since they typically operate at lower temperatures, and therefore lower efficiency. The amount of water needed increases rapidly as the efficiency goes down. For instance, a decrease in efficency from 33 percent (typical for a nuclear power plant) to 20 percent doubles water requirements, all other things, such as cooling method and ambient conditions, being equal. Fortunately, concentrating solar power plants can be air-cooled. UREZ assumes dry concentrating solar power plants as the defualt technology for solar, though in the 2010 report, photovoltaics were also considered.[93] The use of water in cleaning CSP mirrors is estimated by the Department of Energy at about 2 percent of evaporative losses; this has been included.[94]

We have used water data from the National Renewable Energy Laboratory (Table VI-11).

Table VI-11: Water requirements for thermal power plants (in gallons per MWh)

Plant Type	Steam Condensing	Auxiliary Cooling and Hotel Load	Total
Stand-alone steam plant	720(1)	30(2)	750
Combined-cycle plant	240	110	350
Parabolic Trough with dry cooling	0	80	80

[92] It is the fourth largest use in terms of water withdrawal in Utah. (Synapse 2010 p. 43)
[93] UREZ II 2010 pp. 4-3 and 4-4
[94] DOE 2009 p. 4

(1) evaporation + blowdown = 12 gallons per minute/Megawatt

(2) estimated at ~5 percent of evaporation + blowdown

Source: Adapted from NREL Troughnet 2010. Auxiliary and hotel load water requirements are those needed for sanitary, drinking, building cooling and cleaning, and other functions not associated with condensor system water requirements.

Geothermal power plants, which typically operate at relatively low steam temperature, have low efficiency and therefore very high water use. Dry-cooled geothermal plants are possible, but the loss of efficiency at temperatures above 50 or 60 degrees F is very severe, leading to loss of expensive capacity in the summer, when capacity is needed most. Thiscan be seen in Figure VI-14.

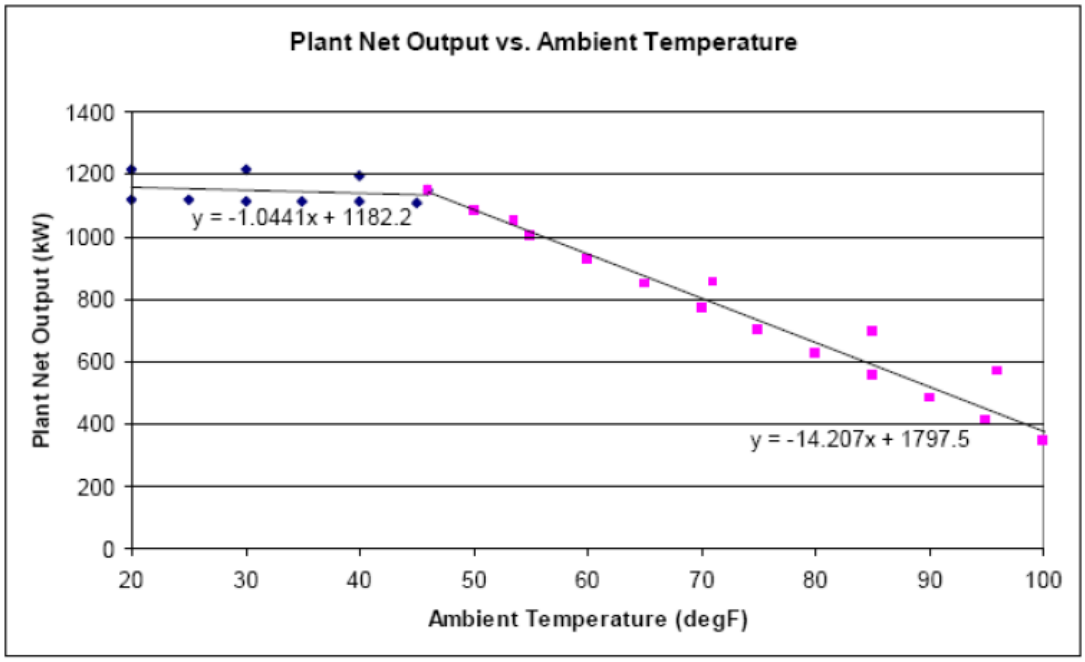

Figure VI-14: Geothermal plant output versus ambient temperature showing drastic loss of capacity at higher temperatures.
Source: UREZ II 2010 p. 4-3

In view of the data in Figure VI-14, we have assumed wet-cooling for geothermal power plants. Geothermal plants operate at a variety of temperatures and efficiencies. We have assumed an efficiency of 20 percent and water use at double that for coal or nuclear plants, or 1,500 gallons per MWh.

Finally, two of the scenarios have carbon capture and storage associated with them. CCS technologies vary in the amount of water required, but generally it is very large. The 2010 Interagency Task Force report provides a range of water uses in coal-fired power plants, ranging from about 400 gallons per MWh to about 1,000 gallons per MWh. We have used a value of 600 gallons per MWh in this report.[95]

[95] Interagency Task Force 2010 Figure A-8 (p. A-13)

For combined cycle natural gas power plants with CCS, we have increased water use by 75 percent relative to the value shown in Table VI-11.

The water use in 2050 in the five scenarios is shown in Figure VI-15. The value in 2010 is shown for reference. Note that this value is calculated using the same assumptions as for the scenarios and does not represent actual PacifiCorp water use attributable to its electricity supply to Utah.

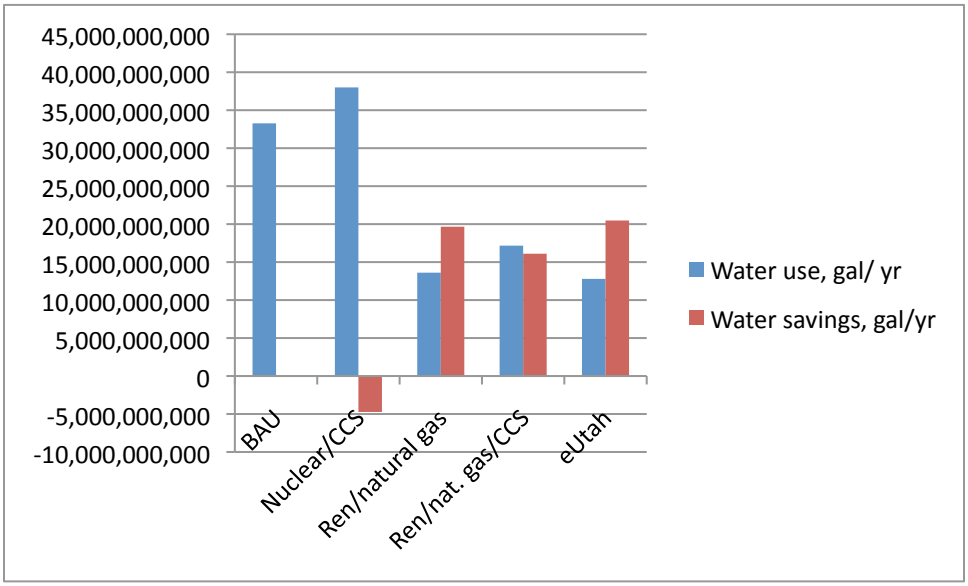

Figure VI-15: Water use in 2050 and savings compared to the BAU scenario, in gallons per year. Water use shown is mainly consumption by evaporation plus some blowdown water for cooling towers.

Note that the Nuclear/CCS scenario actually results in an increase in water consumption relative to the BAU scenario due to the water requirements of carbon capture and storage. The main water use in the remaining scenario is for geothermal generation.

At 0.56 cents per gallon as the cost of water, which is a typical water cost in Utah,[96] the Nuclear/CCS scenario incurs an added water cost of about $26 million compared to the BAU scenario, while the Renewables/Natural Gas/CCS scenario and the eUtah scenario have water cost savings of over $100 million in the year 2050. Carbon capture and storage lowers the savings in the Renewables/Natural Gas/CCS scenario to about $90 million.

Cooling tower related costs should include pollution of the water due to the extensive use of biocides and algaecides as well as chemicals, including chromium compounds in some cases, to prevent corrosion. Since cooling tower water must be discharged into rivers and streams from time to time due to the buildup of minerals and chemicals in it, there would likely be a need for water treatment before use as potable water. These costs have not been included here.

Finally, the marginal cost of water may not be a very good indicator of things to come. With a population that is projected to more than double by 2050, competing demands for water, including for potable water, could make the competition for water much more intense than it already is, possibly

[96] We have used the geometric mean of the lower and upper bounds of the cost of water given in Synapse 2010 p. 49.

giving renewed meaning to the famous quip "Whiskey is for drinking; water is for fighting over" (attributed to Mark Twain).

I. Health costs

The Synapse study concluded that the externalities due to health and water use amounted to between $36 and $45 per MWh in Utah, based on estimating the externalities of existing coal plants.[97] Almost all these costs were related to health damage (estimated excess deaths and diseases). Since existing coal plants are assumed to be phased out before 2050, these externality cost estimates do not apply even to the BAU scenario in 2050, which relies heavily on coal, since those coal plants would all be built after 2020. However, some costs would apply in the interim, since we assume that plants are retired after 60 years in the BAU scenario and 40 years in the others. However, this is a schematic approach to developing the scenarios here rather than an actual schedule. In view of that, we are not including quantitative benefits of reduced air and water pollution that would accompany a transition to mainly renewable energy sources. Whatever net benefits (after counting the added environmental costs of renewable energy sources) there are for the renewable scenarios would lower the cost of generation estimated here; correspondingly it would also lower the cost of reducing CO_2 emissions.

J. Jobs

We recognize that there are communities in Utah that are especially reliant on coal. Any proposal to phase out coal from the electricity system would impact those jobs and communities. Though renewable resources are distributed across the state, the individuals directly employed in the coal industry to meet Utah's generation needs are located in just three counties in Utah's coal belt. These are Emery, Sevier, and Carbon counties. Because this analysis focuses on Rocky Mountain Power's service area for data and policy reasons we are not analyzing the Intermountain Power Project which services mostly California municipalities nor are we analyzing the Bonanza plant which sells its power to Colorado.

There are 1,850 direct and indirect support jobs in the coal mining industry in Utah, according to the draft report of the Utah Energy Initiative, formed by the Governor of Utah.[98] Coincidentally and beneficially, the coal mining areas as well as contiguous counties possess very substantial renewable energy resources. Hence, public policy can aim not only to ease the transition but to ensure that there are comparably paid jobs in the energy sector in renewable energy construction and operation.

There are many studies indicating higher job creation in the renewable energy sector compared to fossil fuels and nuclear power. However, we do not engage in a substantive analysis of the jobs impacts of the various scenarios studied here. This is due to the complexity of the issue. For instance, solar is currently more expensive than fossil fuels. In this study, we assume that coal-fired electricity in the absence of carbon constraints will remain cheaper than solar energy. However, this is an approach with high risk of carbon-related costs, which in turn would require investments to backfit coal-fired power plants—and more jobs. Like the problem of distributed complex grids, the jobs issue was too complex to address quantitatively in this study.

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[97] Synapse 2010 p. 4

[98] Utah Energy Initiative Draft 2010 p. 3

There are three complementary ways to reduce or eliminate the impact of higher renewables (or for that matter nuclear or coal with CCS) on cost:

- **Reduce the cost of renewable energy until it is competitive with fossil fuels**. This might indeed happen, if the Department of Energy achieves its target of solar PV at $1 per peak watt. Utah would not only likely have a large solar industry for electricity for its own use, but it could export it to neighboring states.
- **Increase investment in energy efficiency**. Since the cost per MWh of many efficiency measures is much lower than that of renewables, nuclear, or coal with CCS generation technologies, balancing investments in efficiency and renewable generation would create new jobs while maintaining energy expenditure dollars with the state.
- **Become a leader in advanced energy technologies** to attract investment not only in new plants but also in research, development, and demonstration. Utah already has some ambitious efforts in this area.

Beyond these generation considerations, there continues to be a question of how long Utah coal supplies will last. Utah has estimated remaining recoverable coal reserves of 15 billion short tons,[99] the recoverable reserves in existing mines are rather low—201 million short tons, or less than 12 years at the present rate of consumption. Investment in new mines may be difficult due to the uncertainty surrounding the use of coal in power plants, now reinforced by California's ambitious target for renewable electricity. It appears that a transition in the coal mining area may be needed in any case. Renewable energy is one obvious choice.

[99] UGS Coal 2010 Table 2.3

VII. Notes on Investment Planning

A. Carbon risks

Given the large uncertainties in estimating future loads, unit capital costs, and carbon price (or tax), the differences between the scenarios described are not very large. The sensitivity analysis shows that one or the other approach could be better depending on the specifics of cost. How then to pick an investment strategy?

An important parameter in the current context is the carbon price risk. We have shown in Chapter VI that the present value of the cost of carbon emissions in a scenario that fails to take this risk into account over a prolonged period could be very large. The bar chart for the BAU scenario carbon emissions costs is reproduced here for convenience.

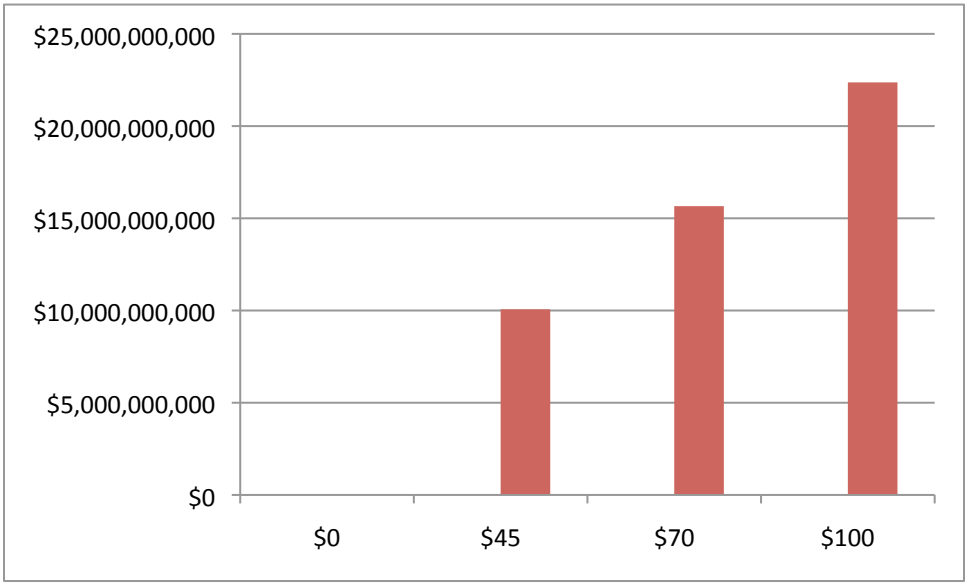

Figure VII-1: Present value, in 2010, of carbon emission costs at four prices for BAU scenario emissions in the 2020 to 2050 period.

Figure VII-1 should be seen as a schematic illustration of the consequences of persisting in a certain investment direction (we note that this is not the direction being pursued by PacifiCorp). A significant, persistent carbon price would elicit a change in investment strategy towards some mix of natural gas, renewables, coal with CCS, or nuclear, and retrofitting existing power plants (such as existing combined cycle power plants) with carbon capture and storage technology. Nonetheless, the inertia of some investment directions is much larger than others, given that the lead times for power plants are quite different. The inertia will be greater for investment directions that rely mainly or largely on coal and/or nuclear for new generation.

B. Financial risks

Financially, one of the most important parameters is the amount of capital commitment to generation investments in the pipeline at any time to build the selected portfolio. This reflects the per kilowatt capital costs, unit sizes, and lead times needed to build power plants. Assessing the total cost of projects under construction at any time provides a measure of the risk of the approach, since load, carbon prices, and fuel costs can change suddenly. If the total financial commitment at any time is relatively large and such large commitments persist in a particular investment strategy, then it would be a more risky one, other things being equal.

To illustrate this approach we compare the Nuclear/CCS scenario with the Renewables/Natural Gas scenario. For simplicity we assume that all the baseload generation in the Nuclear/CCS scenario is nuclear. This allows a clear comparison of nuclear-related financial commitments to the Renewables/Natural Gas related commitments. Both have about the same carbon reduction target. Both have about the same exposure to natural gas price risk. We compare the two scenarios using the base case capital costs described in Chapter VI and the following values for lead time:

- Six years for nuclear power plants, coal fired plants with carbon capture and storage, and geothermal power plants.
- Three years for combined cycle natural gas-fired power plants.
- Two years for wind, solar, and single-stage gas turbine peaking plants. We assume that storage will be built along with the wind and solar plants. The compressor and expander are assumed to have a lead time of two years and the cavern a lead time of five years.

Figure VII-2 shows the result.

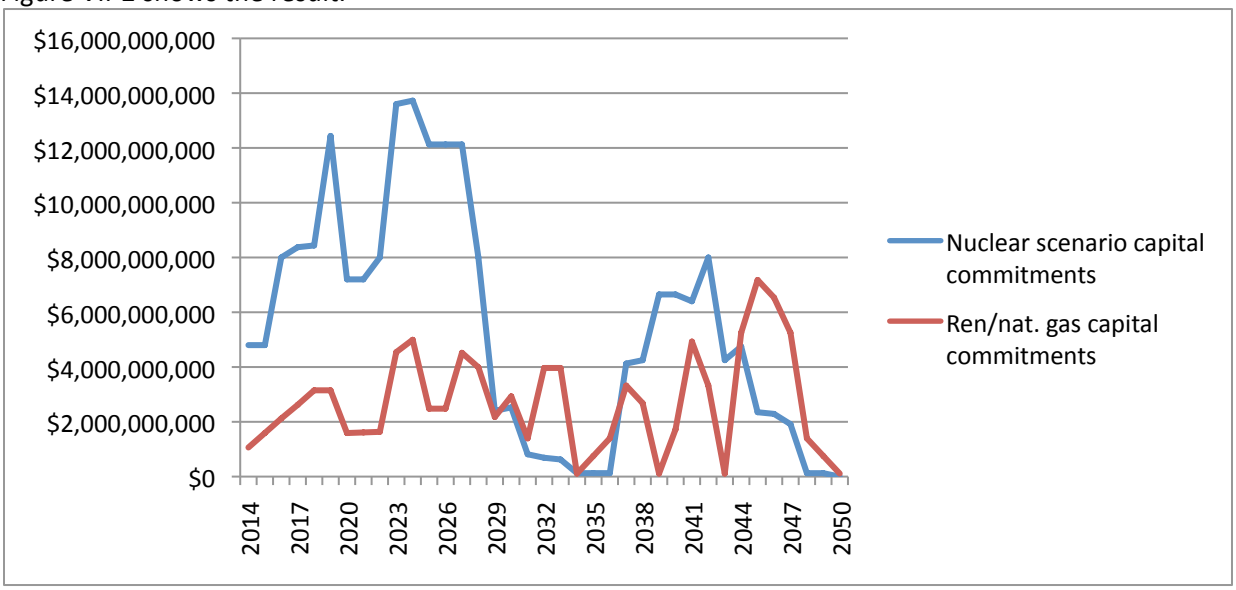

Figure VII-2: Capital commitment in any year in the 2014 to 2050 period in the Nuclear/CCS and Renewables/Natural Gas scenarios.

The chart shows the total value of projects in the pipeline at any time. Note that the amounts are larger for the nuclear case not because the cost of each project is that much larger, but because each project takes much longer. The only cost element of the Renewables/Natural Gas scenario that has a comparable lead time is the cavern, which has a small relative cost. We have taken this into account in

developing Figure VII-2. It is easy to see that the combination of long lead times and high capital costs makes the Nuclear much more risky than the Renewables/Natural Gas scenario. Further the areas under the respective curves, which represent the cumulative risk over the 2020 to 2050 period also show the same result: the Nuclear/CCS (with only nuclear as baseload and no coal with CCS) scenario have about double the risk as the Renewables/Natural Gas scenario. [100]

Doubling the risk is a non-linear matter from the point of view of a company strategy if the total amount of commitment to construction projects becomes comparable to or greater than the market capitalization of the company. This is typical of U.S. nuclear projects, which are carried out by privately owned companies. For instance, the $22 billion Progress Energy two-reactor project, mentioned earlier, is about 70 percent larger than its market capitalization of $12.86 billion at the time of this writing.[101]

This comparison actually understates the differences in risk. Experience has shown that nuclear projects can incur huge delays. Six years is a modest estimate for lead time in the United States. Delays would greatly increase the differential between the two scenarios in the favor of the Renewables/Natural Gas scenario. For instance, Florida Power and Light estimated in 2007 that a delay of one year towards the end of a two-reactor nuclear power project would result in an increase in costs of $800 million to $1.2 billion.[102]

The risks are actually larger than calculated here since we have not taken into account the fact that all presently certified reactors are very large—more than 1,000 MW per unit. Single units of more than 1,000 MW are quite unsuitable for Utah's electricity sector. Were a large unit size to be used it would need electricity markets out of state; failing that, the addition of such a large capacity would create considerable overcapacity for several years, resulting in added costs. We have assumed that unit sizes will be 200 MW to 700 MW for the baseload elements in the Nuclear/CCS scenario (either coal or nuclear) and that larger unit sizes will find markets outside of Utah at no risk. [103]

The risk of carbon capture and storage projects is rather more difficult to estimate, given that the technology is not yet commercial in the context of electricity generation. For instance, siting and safety questions have not yet been fully resolved in the context of the large amount of CO_2 that must be stored for very long periods of time. As noted, we have assumed, based on available literature, that the costs of coal with CCS will be comparable to nuclear. Here we assume the financial risks will be comparable as well, since unit size will be larger than wind or solar and lead times will tend to be long. The risks will be variable from one site to another, since CCS risk will depend partly on the size of the storage reservoir to be developed, the number of plants it would serve, and the length of the pipelines for transporting the CO_2 from the power plant to the underground storage location.

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[100] The balance would be somewhat different with coal plus CCS since the fuel costs of this would be higher and the capital costs somewhat lower. The base case levelized costs including fuel, O&M, and capital charges for both are the same.

[101] NYSE 2010 Progress Energy, viewed on December 2, 2010 at 11:54 AM

[102] FPL 2007 p. 52

[103] There has been considerable discussion of small modular reactors as a way to reduce the cost and the overall financial risk of nuclear projects. The discussion focuses on the potential positive points of such reactors, such as cost reductions that can be achieved by mass manufacture like cars in an assembly line, but less on problematic facts such as the loss of economies of scale as reactor size goes down, how assembly lines in foreign countries, especially low-wage countries would be inspected, what the procedures for recall might be, etc. None have been licensed. The present indications are that the opinions of the promoters lean rather precariously to the optimistic side. An overview of the issues associated with small modular reactors is provided in Makhijani and Boyd 2010.

The conclusions that emerge from this analysis are reflected in the financial and electricity generation worlds. The relatively low risk of natural gas combined cycle plants is widely recognized in the industry. Natural gas and wind are at the center of utility investment strategy at present, including at PacifiCorp. Even the CEO of Exelon, has noted the current prospects of natural gas make nuclear impractical.[104] The situation bears out the judgment of the CEO of GE, Jeffrey Immelt, who (while arguing for nuclear loan guarantees) told the *Financial Times* in November 2007 that were he the CEO of a utility, he "would just do gas and wind….You would say [they are] easier to site, digestible today [and] I don't have to bet my company on any of this stuff. You would never do nuclear. The economics are overwhelming."[105] The observation about nuclear being a bet-the-company risk is one of the principal reasons that Wall Street refuses to finance nuclear power plants.

Despite the widespread acknowledgement of nuclear risks, considering nuclear in the investment mix has become a matter of convention though there is essentially no merit to it, especially in the Western Interconnection, where there are vast renewable resources available. The industry has asked for federal loan guarantees. Yet nuclear investments are turning out to problematic even with such guarantees. The most dramatic example is the rejection of the terms of a federal loan guarantee by Constellation Energy, which has put a large nuclear project in Maryland (that had the advantage of a partnership with the largest nuclear power company in the world, the Electricité de France) in limbo.[106]

The above analysis indicates that nuclear power is essentially of no value, at least in the context of Utah's electricity sector for the foreseeable future. PacifiCorp does not have active plans to consider nuclear power in the 2010 to 2020 time frame; nor does the draft of the Governor's Task Force give it any place in the next ten years. Indeed, there are a number of caveats quite apart from the time frame:[107]

> **Nuclear power generation deserves additional evaluation, but will not be available for electricity generation in this 10-year strategic plan.** The feasibility of future nuclear energy development in Utah will be impacted by the emerging role of nuclear energy nationally, as well as water, waste disposal, size of the plant, rail access, transportation of spent fuel, transmission costs, and available certified designs.

C. Carbon capture and storage

The importance of coal in Utah lends considerable weight to investing research and development (R&D) resources in carbon capture and storage that may not otherwise be justified given the availability of renewable resources in Utah. However, there is an additional critical and rather new reason to give a place to CCS R&D. The analysis in this study has shown that reducing CO_2 beyond 80 percent can be accomplished in more than one way. However, since natural gas combined cycle power plants have much lower CO_2 emissions than coal, CCS is less expensive with combined cycle power plants than it is with coal.

[104] Rowe 2010
[105] As quoted in McNulty and Crooks 2007. Emphasis added.
[106] PennEnergy 2010, viewed on December 2, 2010
[107] Utah Energy Initiative Draft 2010 p. 9

The use of CCS with coal has been the topic of the most R&D, evaluation, and public policy debate. This is understandable, since coal is by far the largest fuel source for electricity production in the United States and in several other key countries, including China and India. The same approaches that are used for CCS with coal-fired power plants can also be used with solid biomass fuels.[108] The new facet that emerges from this analysis is the importance of developing CCS with combined cycle natural gas-fired power plants. This is an area that has not received much attention because CO_2 emissions from such plants are 35 to 40 percent of those of a typical coal-fired power plant.

The federal Interagency Task Force evaluated new natural gas combined cycle plants along with a number of different approaches for CCS with coal. Figure VII-3, reproduced from that report, shows a summary of the economic analysis in it. The overall cost per MWh without CCS is comparable for the combined cycle plant (somewhat higher in the Interagency Taskforce report than in this one). The increase in cost of generation due to CCS was $44 per MWh. The overall increase in the cost of coal generated electricity as estimated by the Task Force was $40 to $65 per MWh, depending on the technology used for generation. In this study, the cost of coal-fired electricity using a pulverized coal plant was estimated at $74 per MW in the base case. We used $150 per MWh for coal with CCS, for a cost differential of $76 per MWh.

When avoided costs of CO_2 emissions are considered, CCS with natural gas is more expensive at $114 per metric ton. However the overall costs are lower because the total emissions from a natural gas combined cycle plant are 35 to 40 percent of a coal-fired power plant. For requirements of high levels of reduction of CO_2 it would be attractive to consider natural gas-fired power plants with CCS, as demonstrated in this study.

Moreover, natural gas combined cycle power plants have been a mainstay of recent generation investments and are becoming more so as the perceived risks of investments in coal increase. Like pulverized coal-fired power plants, natural gas combined cycle plants can also be backfitted with carbon capture technology. The National Energy Technology Laboratory has published an analysis of the level of CO_2 price (or tax) at which such retrofitting would become economical.[109] The study concluded that it would be economical to capture CO_2 by retrofitting a natural gas-fired power plant if CO_2 emissions cost $65 to $72 and 90 percent of the CO_2 were recovered. This corresponds to an increase of less than $30 per MWh of electricity generation. In contrast, backfitting a coal-fired power plant would cost $89 per MWh, according to the estimate of the Interagency Task Force shown in Figure VII-3. The per-metric ton cost differential is not great only because the amount of carbon to be captured in a coal-fired power plant is much greater.

[108] This was a major reason for recommending the development of CCS in Makhijani 2010a.
[109] NETL 2010

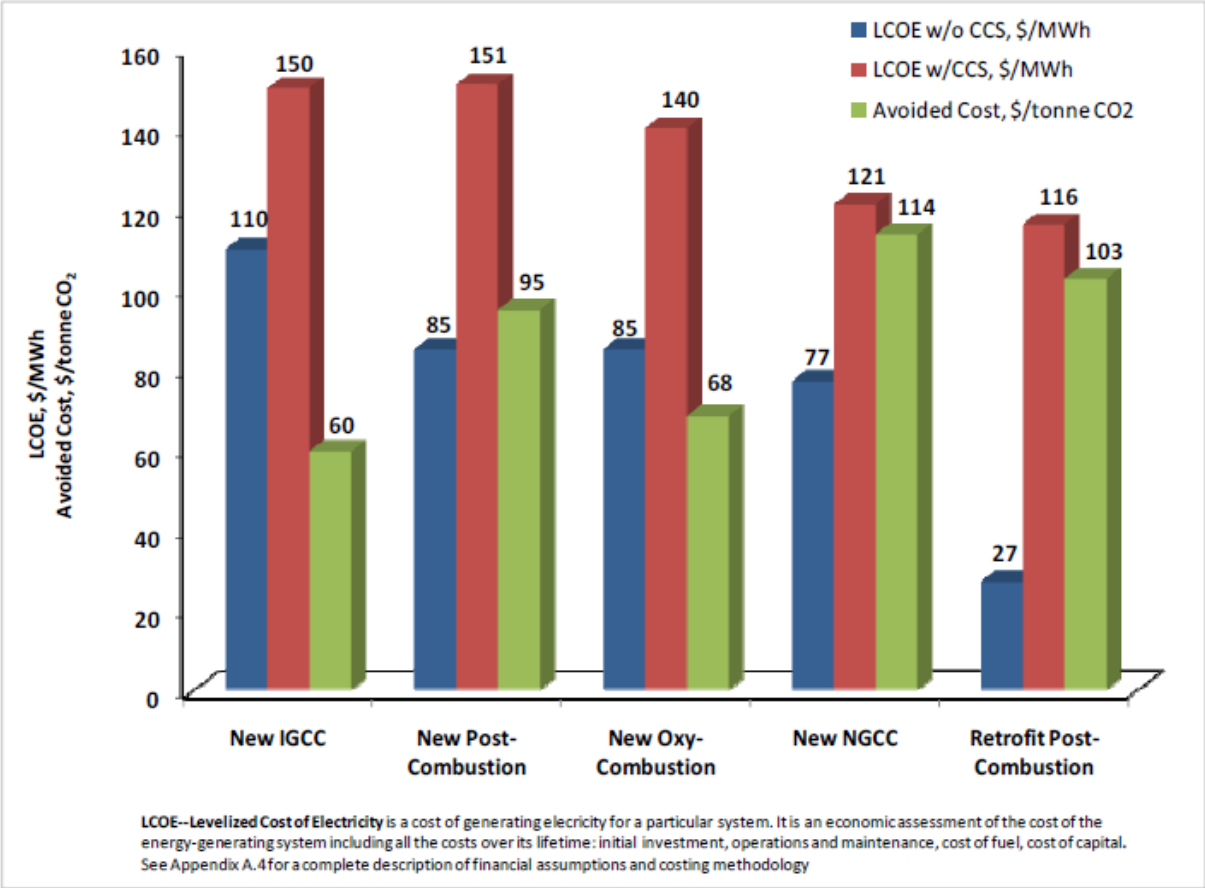

Figure VII-3: Costs of electricity generation with and without CCS for various technologies in new fossil fuel plants. All examples are for coal, except NGCC, which is a "natural gas combined cycle" plant. Source: Interagency Task Force 2010 Figure A-9 (p. A-14)

The State of Utah is already a leader in coal-related CCS research and development, with its agency, USTAR, sponsoring or enabling some of this work.[110] It would put Utah even more at the head of this field if CCS technology, both for retrofitting existing plants and for new plants, were added as a major component of this research.

D. The IRP process

This analysis indicates that more insight is gained into an investment strategy that calculates the cost of reducing carbon by different approaches than by assuming a price (or tax) for carbon emissions and creating generation portfolios. Setting up scenarios to actually calculate what the cost of CO_2 reductions would be at various target levels provides a cost estimate that, in turn, can be used to estimate risk if no action is taken.

[110] See the USTAR website at http://www.innovationutah.com.

Secondly, it is critical to take into account the overall financial commitments demanded by a particular investment direction. The analysis of comparative risk indicates that it is much less risky to proceed in the direction of renewables plus natural gas combined cycle power plants than to focus on traditional central station thermal power plants as the mainstay. But to go in that direction, it is essential to develop contingency plans for storage.

Such considerations indicate that a revamping of integrated resource planning to make the greatest risks more transparent would be salutary. We note here that the Division of Public Utilities in Utah, in reviewing PacifiCorp's 2008 IRP, has also concluded that the IRP process needed a complete reevaluation:[111]

> The Division believes that the IRP process has evolved over the 19 years since the IRP Standards and Guidelines were issued by the Utah [Public Service] Commission. The Division has observed a number of issues, problems, improvements, delays, and many other changes over this time period. The Division recommends that it is now time to revisit the entire IRP process. In particular, the Division believes that the IRP process has become cumbersome, and in order for it serve as a meaningful planning process, the IRP process itself needs to be formalized.

The analysis in our report indicates that, so far as centralized generation investments are concerned (that is, apart from efficiency and distributed, intelligent grid, demand dispatch, and related issues), the focus should be on solar, wind, geothermal, and combined cycle natural gas power plants. Within this set, solar is still on the higher cost side, so that in the immediate horizon, a wind, natural gas and geothermal focus is warranted. The first two are part of PacifiCorp's IRP, which moreover, does not plan any coal or nuclear units in the 2010 to 2020 planning period.

However, risk reduction is more than just choosing generation technologies for a few years. It requires preparation for long-term strategic directions. The following choices are indicated by the analysis in this report:

1. Increasing solar and wind energy will require investments in storage. Currently only pumped hydro storage and compressed air energy storage are commercial large scale options. The former is not available to Utah. It is therefore critical to evaluate and develop sites, examine the environmental impacts, and seek permits so that when solar and wind generation increase beyond the single digit percentages, storage can be put into place in a reasonable time and cost. PacifiCorp does not appear to have active plans for large scale storage at present. The State of Utah should at any rate develop such plans. As noted earlier, Magnum Gas Storage is developing a site at which more than one cavern can be constructed, so that both natural gas and compressed air storage can be co-located. PacifiCorp might usefully revisit the issue and develop plans for CAES.
2. Batteries are still too expensive to consider for large-scale storage (by which we mean thousands or tens of thousands of megawatts hours). But it could yield significant benefits when combined with investments in distributed generation, notably solar PV.
3. Given that spilled energy is a major concern with high penetration of renewable resources, development of demand response methods should be a high priority. This should go much beyond present demand-side-management programs in the PacifiCorp portfolio. For

[111] Utah Division of Public Utilities 2009 p. 2

instance, the implementation of a pilot project in which a demand aggregator would provide resources on the same basis as spot market electricity purchases would illuminate the costs and prospects of reducing spilled energy, reducing generation costs at peak load times, and reducing the installed capacity needed whether it is within a conventional peak load framework or a renewable "relational peak demand" framework.

4. It is important to coordinate efficiency improvements, for instance, in the area of advanced passive design buildings and zero net energy buildings with the development of a suitable distributed grid that can be flexible enough to handle the various elements. The approach recommended by the American Institute of Architects—steadily moving towards a zero energy building by 2030—would have a major impact on electricity and energy load as well as on the shape of the demand curve. Rather than react to developments, it would be useful to integrate this into utility planning and estimate what it would mean in the next IRP.
5. Development of models for optimizing a variety of elements (as distinct from macro-level IRP approaches) appears essential to being ready to seize the opportunities that are presenting themselves with lower renewable energy costs. While there is no perfectly clear crystal ball in these matters, the costs of solar electricity (either PV or CSP or both) are coming down rapidly even as other costs have been increasing. Solar PV costs have declined by a third or more in the same period as capital costs of wind energy have approximately doubled (in the last several years). Optimization of a renewable system is a major issue, since without that approach a significant portion of the costs will be driven by spilled energy.

A word about smart grids is warranted here. There has been too much identification of smart grid with smart meters, which have been the focus of the investment so far. This term that covers different levels of "smart" from remote meter reading, at its simplest, to complex devices that provide two way communication of large amounts of information about the state of everything from a specific device in a home to the state of the entire grid. The development of an intelligent grid is still in its infancy, much in the stage of, say, early email systems as compared to today's Internet and smart phones. A number of issues surrounding the development of technical standards, communications protocols, communications security, and security of systems, privacy, cost, and pricing must be considered together. The promise of the approach is great—given the potential for reducing cost and pollution, creating jobs, allowing much greater freedom of choice to consumers and a much better functioning of electricity and energy markets. At this stage, pilot programs that integrate the various elements of an intelligent electricity system need to be developed. There are already some lessons learned as with the Boulder, Colorado, project, where the cost of a dedicated communications system turned out to be unexpectedly high.

It is also essential to start this process now, because many developments such as encouragement of zero net energy buildings are creating the necessity to integrate many levels of efficiency, generation, and storage in the comprehensive system. Without some integrative approach, individual measures that benefit, say, building owners could well cost the system more, for instance, in increased distribution system costs.

Utah could spur renewable energy development in the very areas that now are dependent on coal. Therefore, the development of an infrastructure to lay the foundation for large-scale deployment of Utah's renewable resources is warranted. The draft report of the Governor's Utah Energy Initiative also

recommends the same thing.[112] The UREZ reports and other work done so far have provided a starting point. We hope that this report will help clarify the next steps in helping Utah create an economical, efficient, and environmentally sound electricity sector.

[112] "Given the current situation with coal as a primary fuel for base-load electric generation, Utah needs to develop every viable renewable energy project it can identify. (Utah Energy Initiative Draft 2010 p. 9)

Attachment A: Renewable resource choices

To create the hourly wind and solar generation numbers for our analysis we begin with the zones identified by the Utah Renewable Energy Zones (UREZ) Task Force. We used the estimates in UREZ Task Force Phase II Report (UREZ II) without modification.[113]. We did not use all UREZ identified zones in the analysis for our model, because the total resources required for creating the model are smaller than the available Utah renewable generation capacity. Moreover, hourly data are required for our analysis. They are not available for all zones. Instead of creating an hourly data set for all UREZs, we created a portfolio of generation assets representative of Utah potential that could be scaled up in our modeling as generation requirements increase. We used UREZ II Figure ES-1, which is reproduced in Chapter III, as a geographic guide to compilation of hourly data for our model.

In order to create the most realistic model possible, we restricted ourselves to UREZ sites for which actual hourly wind and solar data were available. Without hourly data, a realistic matching of supply to demand would not be possible and the sizing of storage capacity and related compressor and generator facilities would not reflect the variability in Utah's renewable resources, not the complementarity between solar and wind resources and their combination to the patterns of demand in Utah.

Wind Generation Data

UREZ I identifies wind energy sites[114] and associates many of them with anemometers placed through the Utah Anemometer Loan Program (UALP).[115] These sites are divided amongst the zones identified in the UREZ II report. We used data from the Utah State Energy Program to correctly associate the UREZ I wind energy sites and UALP data sites, with the UREZ II zones.[116] We supplemented this information with UREZ II Figure ES-1, UREZ I Appendix C, UREZ I Figure 13, UREZ I Figure 12, and the UALP online map.[117] We then were able to identify UREZ II zones for which there was publicly available data. Table A-1 reports our UREZ II zone selections and their associated anemometer sites.

Table A-1: UREZ and Anemometer Tower Names and Capacities

UREZ Name:	**UALP Tower:**	**UREZ Capacity:**
Black Rock	Cricket II	700 MW
Cedar	Elmo	250 MW
Cedar Creek	Snowville	315 MW
Duchesne	Duchesne	320 MW
Garrison	Garrison	120 MW
Helper	Soldier Summit	480 MW
Milford	Milford	860 MW
Total Capacity:		**3,045 MW**
% of UREZ Total Capacity (8,875 MW):		34%

[113] UREZ II 2010 Table ES-1
[114] UREZ I 2009
[115] UGS 2010 Site Data
[116] The tables were in the following emails: Curtis Carrigan, Emails to Arthur Morris, 3 March 2010 and 2 August 2010
[117] UGS 2010 Site Data

These data taken together provide a workable and representative basis for this feasibility level study because they allow us to create a model of supply based on actual meteorological variation in the state of Utah.

In some cases, we did not find hourly data for a whole calendar year. In such cases, we used data for 12 continuous months for such stations. In a few cases, there were minor gaps in measurements, which were filled by interpolation. The UGS UALP program is an impressive and transparent program and an invaluable resource in our analysis. Yet, the procedure used here for an initial examination of high penetration of renewable energy in Utah would not be suitable for an actual design of a grid. But it suffices for this study. Expansion and improvement of the wind energy database is important to improving the prospects for wind energy development; it is even more important to deliberately use geographic diversity as a design element to reduce the impact of intermittency of wind energy supply at any particular site.

All wind speed data were downloaded from the UALP website. Several steps of manipulation were necessary before the data were converted into hourly megawatts and loaded into our spreadsheet model. These steps are listed and explained below:

1. **Collate downloaded files into complete years.** Because the UALP data is separated by calendar year and some years have partial data each site's data was collated so that every file began January 1st at 00:00 and ended December 31st at 23:50 though some files combined years. At this point all data were in ten-minute time-steps. It is important to note that these anemometers did not collect data for the same years, thus some inter-annual meteorological variation is part of our data set, however, the goal of our study is to demonstrate how to deal with real world variation, not to perfectly estimate or forecast this variation. A small number of sites had incomplete data in spite of our efforts to only select zones that had complete data associated with them. When necessary random values were selected using either dummy week construction or random number generator functions designed to match the statistical characteristics of the surrounding data. The total quantity of data gaps filled in this way constitutes less than one percent of the total observations in the study. These estimated data points statistically match seasonal and hourly characteristics of the observed data.
2. **Convert ten-minute time-step to one-hour time-step**. To match wind data to the hourly solar and load data in our model we created hourly averages for every hour of the year. This conversion reduced our data set from 52,560 observations for each of our 12 wind sites to 8,760 observations.
3. **Conversion to meters-per-second.** All of the data reported by UALP were in miles-per-hour, for consistency we converted all model input values to Standard International (SI) units.
4. **Conversion to common hub height.** The anemometer tower's wind speeds are reported at either 20-meter or 50-meter hub heights, while UREZ I & II assume 80 meter hub heights in their calculations of capacity.[118] UREZ I Appendix B explains the relationship between wind speeds at different hub heights:

> In nearly all cases, winds increase with height. Thus the average speeds at 80 meters above ground (selected as the basis for this study) will be higher than those recorded at

[118] Elise Brown, Email to Arthur Morris, 10 August 2010

the 20-m and 50-m levels of the USEP stations. The formula to adjust wind speeds to the 80-m height is as follows:

$V_2/V_1 = (z_2/z_1)^{\alpha}$ Where V stands for the average speed at heights 2 and 1, and z stands for the heights and alpha is the power law exponent.[119]

While UREZ I does not list power law or wind shear exponents (α) for its data sites they do list average wind speeds that have been converted to 80-meter hub heights for all of the data sites.[120] We calculated average wind speeds for each of the data sites from the UGS hourly wind speed data already assembled, and used the formula below to calculate α for each site. Since we dealt with many sites, we added a superscript to α to keep track of the various values of the power law exponent.

$$\frac{\log\left(V_2^s / V_1^s\right)}{\log\left(z_2^s / z_1^s\right)} = \alpha^s$$

Where V_2^s is the average wind speed calculated from the Utah Anemometer Loan Program data for the site and z_2^s is the height of that anemometer tower at site s, while V_1^s is the average 80-meter wind speed calculated in UREZ I and z_1^s is 80 meters, and α^s is the wind shear exponent for site s.

We finally convert each of the 8760 wind speed observations for each of our data sites from the 20-meter or 50-meter anemometer hub height to 80-meter wind speeds using the following formula:

$$V_1^t = V_2^t\left(\frac{z_1^s}{z_2^s}\right)^{\alpha^s}$$

Where V_1^t is the 80-meter wind speed at the site in hour *t*, z_1 is the height of the 80-meter tower, while V_2^t is the observed wind speed at the anemometer in hour *t* and z_2^s is the height of that anemometer tower. α^s is the wind shear exponent at site *s,* calculated as described above.

5. **Convert wind speeds (m/s) to electrical output.** To convert the wind speeds to power output we used the Idaho National Laboratory's database of wind turbine power curves. For our analysis we use the GE 1.5 S turbine with a 70.5m rotor, the power curve from NREL originates with the manufacturer of the turbine, GE.[121] This curve allowed us to convert wind speeds to kilowatt electricity output. At this point the data reports output from one turbine at each site. Modeling system power production requires us to scale production to the capacities presented in UREZ II.
6. **Scale output to UREZ Zones**. To represent the generation potential in the selected zones we multiplied the single turbine output calculated in Step 5 by the number of turbines required for the zone capacity identified in UREZ II, and converted the output to MW for consistency within the model.

[119] UREZ I 2009 p. 47
[120] UREZ I 2009 pp. 16-20
[121] INL GE Wind

7. **Total selected sites**. The hourly data from the selected sites are then totaled and input into the spreadsheet model as "Unit Wind Output."

Solar Generation Calculations:

To characterize Utah's solar generation potential and capture the hourly variability in these resources, in much the same manner as employed with wind resources, we combine UREZ data and assumptions with observed meteorological data.

A portfolio of sites was selected from across the state representing diverse geography, quality of resources, and proximity to present fossil fuel resources. As was the case with wind, our selections were constrained by the availability of hourly meteorological data.

Hourly direct normal irradiance (DNI) data were downloaded from the National Solar Radiation Data Base (NSRDB).[122] DNI is reported in the NSRDB data sets in watts per meter squared (W/m^2), the values downloaded can be accurately conceptualized as the amount of energy from the sun hitting a square meter at a 90-degree angle within the zone over the observed hour.

UREZ II outlines the generation capacity of each zone in Table ES-1, while UREZ I offers this standard definition of capacity: "Generating capacity is the maximum output available from a generator."[123] UREZ I asserts that, "a rule of thumb for CSP [concentrating solar power] is that the field of solar collectors required for a 50 MW plant is one square kilometer."[124] These assumptions and the DNI data allow us to calculate the CSP efficiency implicit in this assumption of UREZ. Conveniently, for our purposes, W/m^2 are equivalent to MW/km^2, this makes conversion of DNI data from W/m^2 to MW/km^2 simple.

To convert the hourly DNI data to hourly production data we use a simplified approach that allows easy aggregation of solar data from different sites.

Where $E_{z,t}$ is the electrical output in MW for zone *z* at time *t*, $I_{z,t}$ is the DNI for site *z* at time *t*, A_z is the area of zone *z*, and e_{UREZ} is composed of the average CSP outputs divided by the total insolation for each site, as defined below.

Land areas were calculated for each of the UREZ zones used in the eUtah Solar Generation Portfolio with the following formula:

$$A_z = \frac{C_z}{r_c}$$

Where A_z is the area of zone *z* in km^2, C_z is the capacity of zone *z* from UREZ II Table ES-1 in MW, r_c is the ratio of capacity (MW) to area (km^2) assumed in UREZ I and II to be 50 MW of capacity per km^2.

The 50 MW per km^2 relationship (r_c) implies an efficiency of CSP technology, this efficiency is e_{UREZ} above. To derive this number we use each site's DNI data and r_c. A capacity of 50 MW for each 1 km^2

[122] NSRDB 1991-2005
[123] UREZ I 2009 p. 11
[124] UREZ I 2009 p. 15

means that at peak radiation the CSP technology can produce 50 MW per km^2 installation. The ratio of peak output (50 MW) to peak insolation is the solar efficiency implied by r_c and is e_{UREZ} above. We calculate efficiency implied at each data site to create e_{UREZ} using the following formula for each site:

$$e_z = \frac{r_c}{I_{MAX_z}}$$

Where e_z is the implied by r_c at site *z*, and I_{MAX_z} is the maximum DNI at site *z*.

And:

$$e_{UREZ} = \frac{\sum_{i=s}^{n} e_{z_i}}{s}$$

Where *s* is the number of data sites with hourly DNI data. This unweighted average approach gives a value of e_{UREZ} that is somewhat lower than a weighted average.

According to the above formulae we convert the NSRDB DNI data to peak electrical output.
For reference the table below matches UREZ names to NSRDB data sites.

Table A-2: UREZ and NSRDB Names, with Capacities and Areas

UREZ Name:	**NSRDB Site:**	**UREZ Capacity (C_z):**	**Zone Area (A_z):**
Clive	Wendover	1,876 MW	37.52 km^2
Escalante Valley	Cedar City	2,133 MW	42.66 km^2
Grand	Moab	226 MW	4.52 km^2
Intermountain	Delta	1,564 MW	31.28 km^2
Red Rock	Blanding	1,164 MW	23.28 km^2
Wayne	Moab	1,204 MW	24.08 km^2
Total:		**8,167 MW**	**163.34 km^2**
% of Total UREZ Identified Solar Capacity (14,696 MW)			55%

These output data are then input into the spreadsheet model where they are scaled to meet the generation requirements in combination with other resources (wind, geothermal and, in two scenarios, natural gas). These data supply a realistic picture of the variation and quantity of generation of a geographically and resource diverse generation portfolio.

Attachment B: Scenario assumptions

A. Technical assumptions

1. All scenarios:

- A 12 percent peak margin is maintained for all hours in the year.
- No changes are made to the generation portfolio of PacifiCorp until 2020. It is assumed that any deficits projected by PacifiCorp will be met by purchases.
- Generation elements added after 2020 are for Utah demand only.
- All renewable resources are in-state resources.
- Existing wind capacity is modeled as a new in-state resource, for convenience. This results in somewhat higher cost estimates.
- DSM Class I capacity in 2010 will continue to be available up to 2020.
- Interruptible capacity will grow from the 2010 value in proportion to growth in peak demand.
- Existing PacifiCorp hydropower and geothermal capacity in the East section attributable to Utah (125 MW at 75 percent of the East section total of 156 MW) is maintained as part of existing capacity throughout the 2010 to 2050 period.
- PacifiCorp, like other utilities, engages in both sales and purchases of electricity. The supply scenarios and demand projections in this study exclude all such transactions. This gives rise to some anomalies in the 2010 to 2019 period, but these are not relevant to the cost and planning discussion. It is assumed that gaps would be met by purchases in this period. After 2020, this study assumes that all generation needed is within Utah.
- Additions to capacity planned by PacifiCorp in the March 2010 IRP update for the 2010 to 2020 period are maintained in all scenarios. About 75 percent of the planned eastern section additions are allocated to the PacifiCorp's Utah service area.

2. Business-as-Usual scenario:

- As noted the BAU scenario is NOT the trajectory of PacifiCorp investments in the future. Rather, it is a reference scenario that has continued major reliance on coal, with natural gas providing a supplementary role, as at present.
- Existing fossil fuel plants are retired at 60 years.
- No CO_2 emission controls or constraints are assumed.

3. Nuclear/CCS scenario:

- The nuclear and coal with carbon capture and storage capacity will be about equal.
- Nuclear reactors are not assumed to have the currently sold large unit sizes. Rather, it is implicit that if large sizes are built, the excess power will be sold out of state or that smaller sizes will be available. This assumption provides a rather optimistic view of nuclear power financially, as discussed in Chapter VI.

- Existing fossil fuel plants are retired at 40 years, but the retirements between 2010 and 2020 are kept at 60 years.
- A medium level of efficiency will be achieved relative to the BAU scenario.
- CCS will result in the storage of 80 percent of CO_2 emissions from coal with CCS plants.

4. Renewable scenarios

- All renewable resources will be within the state of Utah.
- Existing fossil fuel plants are retired at 40 years, but the retirements between 2010 and 2020 are kept at 60 years.
- A somewhat higher level of efficiency than the Nuclear/CCS scenario will be achieved.
- CCS will result in gradually rising CO_2 storage, up to 80 percent of CO_2 emissions from combined cycle natural gas-fired power plants by 2050 in the Renewables/Natural Gas/CCS scenario.
- Wind and solar resources will be added in proportion to each other and to storage to maintain the reliability requirement of 12 percent reserve margin over the peak hour. Note that in the case of the renewable scenarios, the peak demand is a relational system peak, as explained in Chapter 2. That is, it occurs when the solar, wind, and storage resources are the lowest in relation to the demand. It may occur at times of relatively low demand, or it may not. It will vary from one year to the next.
- Year-to-year variations in solar and wind data are not taken into account.

B. Economic parameters

Table B-1 Capital costs used for constructing the base case cost estimates

All-in capital costs, $/kW, except cavern	
Nuclear (Note 1)	$8,000
Coal no CCS, BAU	$3,000
Natural gas combined cycle	$1,250
Wind	$2,200
Concentrating solar power, no storage (Note 2)	$2,200
Geothermal Utah average	$5,300
CAES compressor	$300
CAES expander	$400
CAES balance of system	$300
CAES cavern $/kWh (Note 3)	$3

Notes: 1. Nuclear cost estimates for new projects vary a great deal and have been esimtated in the range of $6,000 to $10,000 per kW (all-in costs, including allowance for funds during construction). The Florida Power and Light analysis [delivered] to the public utilies commission of that state estimates all-in costs for nuclear as 75 percent larger than overnight costs.[125] Hence a range of $4,000 to $6,000 for all-in costs translates into a cost range of about $7000 to $10,000. The Progress Energy project in Florida is estimated at $22 billion for 2,200 MW, but this includes about $3 billion for transmission. Net of transmission, the cost is over $8,600 per kW. It should be noted that both projects are heavily subidized by a Construction Work in Progress charge to ratepayers. The South Texas Project of 2,700 MW is estimated at $18.2 billion, or about $6,740 per kW, but it should be noted that even before

[125] FPL 2007, p. 250 of the 251 page pdf file

project construction began costs estimates rose more than three-fold from less than $6 billion in 2007 to $18.2 billion in late 2009.[126]

2. No concentrating solar power plants are included in this study until 2020 (in the eUtah scenario) and until 2025 in the Renewables/natural gas scenario. The estimated cost used for CSP in the 2020 to 2050 period is projected for the 2020 to 2030 decade. See, for instance, CEC 2009, p. 20.

3. The CAES cavern cost is per kWh. For CAES, EPRI-DOE 2004 has been used as the basic source.[127] The capital costs for CAES in the EPRI-DOE report have been doubled for 2010, in keeping with the cost escalation of wind and NGCC, and kept constant thereafter. No cost reduction due to extensive deployment is assumed. The cavern cost for solution-mined salt caverns in the EPRI-DOE report is estimated at $1.75 per kWh for a 10-hour storage cavern, with costs going down for larger storage times and vice versa (EPRI-DOE 2004 Table 15-1 (p. 15-3)). Since the storage amounts in this report are longer than 10 hours, a reference value of $1.50 was assumed in the context of the study and doubled to $3/kWh to bring it in line with the costs of most other energy projects.

Table B-2 Parameters: Parameters used for different energy technologies

Technology	Net cost of capital	Life, years	Capacity factor	Total O&M, including fuel, $/MWh
Nuclear	12%	40	90%	20
Combined cycle natural gas	8%	30	80%/35% See note 6	39.50
Wind	8%	25	29%	10
CSP	8%	25	27%	25
Geothermal	8%	40	85%	20
Coal no CCS	8%	40	80%	28.80
CAES Expander/Compressor	8%	25	Variable	variable
Cavern	8%	40	Variable	

Notes: 1. The 8 percent cost of capital is in the middle of the range for an average Default Investor Owned Utility and a Merchant plant. (CEC 2009 Table 18 (p. 51))

2. O&M costs, base case, assume natural gas fuel cost of $5 per million Btu and coal costs of $1.38 per million Btu, as per the advice of the Advisory Board of this project. The nuclear fuel cost of $7 per MWh is about the present industry average. The non-fuel nuclear O&M cost for the base case is assumed at $13 (and $10 for the low case). For other O&M costs, the Energy Information Administration's Annual Energy Outlook input data and National Renewable Energy Laboratory data were consulted. (NREL 2008 p. 28 (for wind), EIA 2010a (levelized cost section—all types), Stoddard et al 2006 Table 5-3 (for CSP), and CEC 2009, all types)

2. CAES: Heat rate = 4,500 Btu/kWh Non-fuel O&M costs vary by component and are a few dollars per MWh. Total O&M costs, including fuel, are shown here; fuel costs are also separately shown.

3. The natural gas cost in the base case is $5 per million Btu and the heat rate used is 6,500 Btu/kWh (52.5 percent efficiency) for new plants. GE advertises new natural gas combined cycle power plants as having 60 percent efficiency, which gives a heat rate of 5,690 Btu/kWh.[128] However, there was no readily available installed cost estimate for these plants and hence the higher heat rate was used in the estimates in this report. For coal O&M costs

4. Solar and wind: Capacity factors are for the combination of sites selected. For CSP, the value used is near the upper end of the capacity factors estimated for single axis dry-cooled parabolic trough CSP plants in UREZ II (UREZ 2010, p. 4-4). For wind, the capacity factor used is in the middle of those cited in UREZ I 2008, Table 7, for sites with winds averaging 7 meters per second or more.

[126] Hamilton and Caputo 2009

[127] EPRI-DOE 2004

[128] See the GE Energy website at http://www.gepower.com/prod_serv/products/gas_turbines_cc/en/h_system/index.htm, viewed on November 30, 2010.

5. For technologies with a lifetime of less than 40 years, the present value of a replacement prorated for the remaining years is added to the capital cost. For example, the expander cost of $400 per kW is increased by $56. The present value of $400 invested 25 years hence, discounted at 6 percent is $93.20. But this has a life of 25 additional years, or 10 years beyond the 40 year reference time. So only (15/40)*93.20 = $55.92 is added to the capital cost of the expander. A similar calculation is done for other combined cycle, wind, and concentrating solar power plants, as well as the compressor part of the CAES.
6. Combined cycle natural gas plants are used in a baseload mode in the three renewable scenarios at 80 percent capacity factor and in the intermediate load mode in the Nuclear/CCS scenario at 35 percent capacity factor. The capital charges are adjusted accordingly. For simplicity, total O&M costs are not changed since they are dominated by fuel costs in both cases.

Table B-3: Demographic, economic, and electricity growth parameters for the scenarios

Average electricity growth BAU	1.91%
Assumed BAU ratio electricity to economic growth	0.53
Implicit economic growth rate	3.61%
Average population growth rate	1.81%
Per person economic growth rate	1.80%
Size of economy in 2050 relative to 2010	4.12
Utah GDP in 2010, $	$111,000,000,000
Utah GDP in 2050, $	$457,796,169,539
Utah population, 2010	2,927,643
Utah population, 2050	5,989,089
PacifiCorp electricity and economy fraction in Utah	80%
GDP per person in 2010, $	$37,002
GDP per person in 2050, $	$76,438
PacifiCorp generation cost per MWh in 2010 (Note 3)	$41.19
PacifiCorp generation cost, 2010 (estimated)	$1,000,698,611
2010 generation cost as % of GDP	1.13%
2010 households	958,165
2050 households	2,200,285
2010 generation cost per person (all sectors)	$342

Sources: State of Utah population projections. Also see the notes.
Notes: 1. The ratio of 0.53 of electricity growth rate to economic growth rate is based on the 2000 to 2007 historical rate. This may overestimate demand relative to economic growth since the trend has been for this ratio to decline.
2. The generation cost per person is NOT the annual individual direct cost of residential electricty. Rather, it represents the total electricity generation expenditures per person for all sectors in Utah—residential, commercial, industrial, and agricultural. In other words, it represents direct personal expenditures on electricity as well as indirect expenditures in other sectors.
3. Generation cost of $41.19 for 2009 was provided by PacifiCorp, personal communication with Arjun Makhijani, 6 December 2010. This value is assumed constant for existing generation for the BAU scenario and for other scenarios until 2033 (inclusive), when all existing coal plants are retired in these scenarios. This means that we assume no new investments in existing plants, though some may be planned, for instance for pollution control. For non-BAU scenarios during 2034 to 2050, a value is derived using a heat rate of 9,000 Btu for the mix of remaining natural gas generating stations, using the prices of gas as recommended by the Board ($3 to $10), with a

base case value of $5 per million Btu, with a $10 per MWh non-fuel O&M cost. The results for 2050 are not sensitive to these assumptions.

C. Parameters for sensitivity calculations

Cost parameters used in the sensitivity calculations are described below. Note that when no variation is mentioned the parameters are kept the same as in the base case, which has been described in detail above. Six cases were tested:

1. High fossil fuel and nuclear O&M costs: natural gas = $10 per million Btu, coal = $3 per million Btu, nuclear fuel = $17 per MWh and nuclear O&M = $27 per MWh. The high nuclear fuel and O&M cost is taken from the Keystone Joint Fact Finding, which had the participation of the nuclear industry as well as other experts.[129]
2. Low fossil fuel and nuclear O&M: natural gas = $3 per million Btu, coal = $1 per million Btu, nuclear fuel = $7 per MWh and nuclear O&M = $10 per MWh.
3. High nuclear capital cost and risk: capital cost = $10,000/kW (all-in, including allowance for funds during construction) and cost of capital = 14 percent.
4. Low nuclear capital cost: $7,000/kW and 10 percent cost of capital.
5. High solar and wind cost; concentrating solar power cost = $3,000/kW and wind = $2,500/kW.
6. Low solar and wind capital cost: concentrating solar power cost = $1,500/kW and wind = $1,500/kW.

[129] Keystone 2007 p. 11

Attachment C: Advisory Board Members

The eUtah Project: A Renewable Energy Roadmap

Rob Adams, Beaver County Economic Development Corporation

Kimberly Barnett, Environmental Coordinator for Salt Lake County Mayor Peter Corroon

Michele Beck, Director, Utah Department of Commerce, Office of Consumer Services

Kristin Berry, Former Vice President of Energy Financing, Sentry Financial

Jeff Edwards, President and CEO of the Economic Development Corporation of Utah

Bryson Garbett, President Garbett Homes, Former President Utah Homebuilders Association, and Former State Legislator

Professor Ned Hill, Former Dean, Marriott School of Management, Brigham Young University

Ted McAleer, President, Utah Science Technology and Research Initiative (USTAR)

Phil Powlick, Director, Utah Division of Public Utilities

Roger Weir, Industry Expert

Myron Willson, Director of the Office of Sustainability, University of Utah

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