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

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.

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 utilities commission of that state estimates all-in costs for nuclear as 75 percent 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.

[80] FPL 2007, p. 250 of the 251 page pdf file
[81] Hamilton and Caputo 2009
[82] EPRI-DOE 2004

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 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.

[83] 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.
[84] Interagency Task Force 2010
[85] Interagency Task Force 2010 Figure A-9

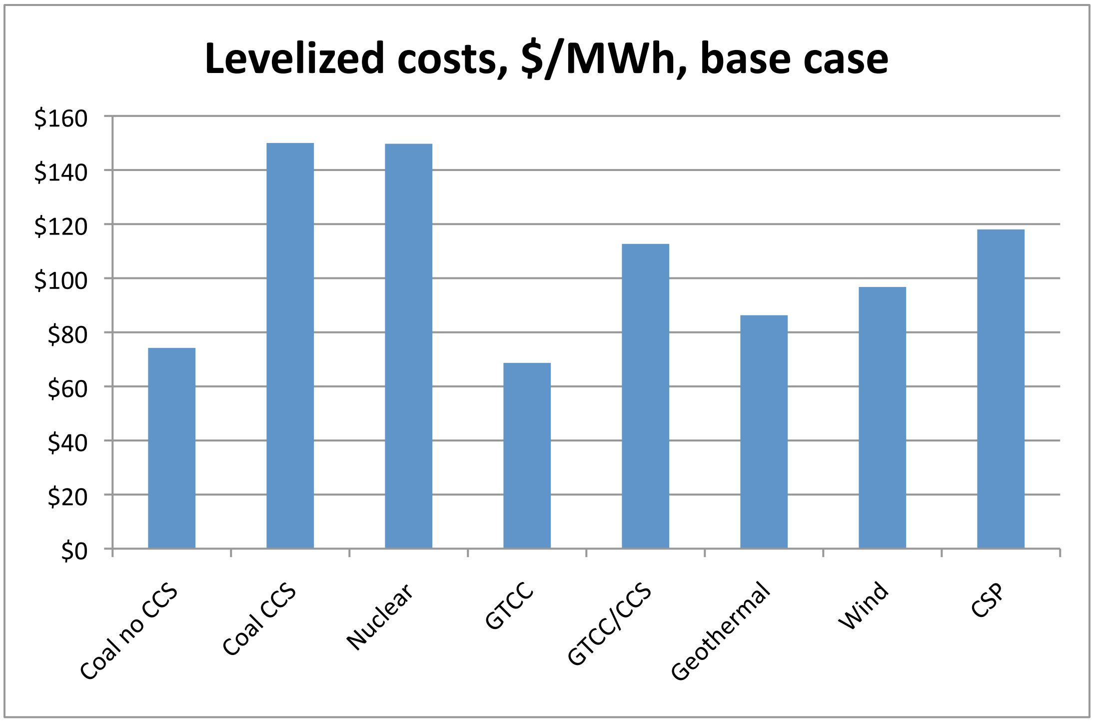

Figure VI-1. Levelized costs of generation technologies used in this report. GTCC stands for a combined cycle natural gas turbine plant. Base case costs are those calculated for the parameters catalogued in this section.

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.

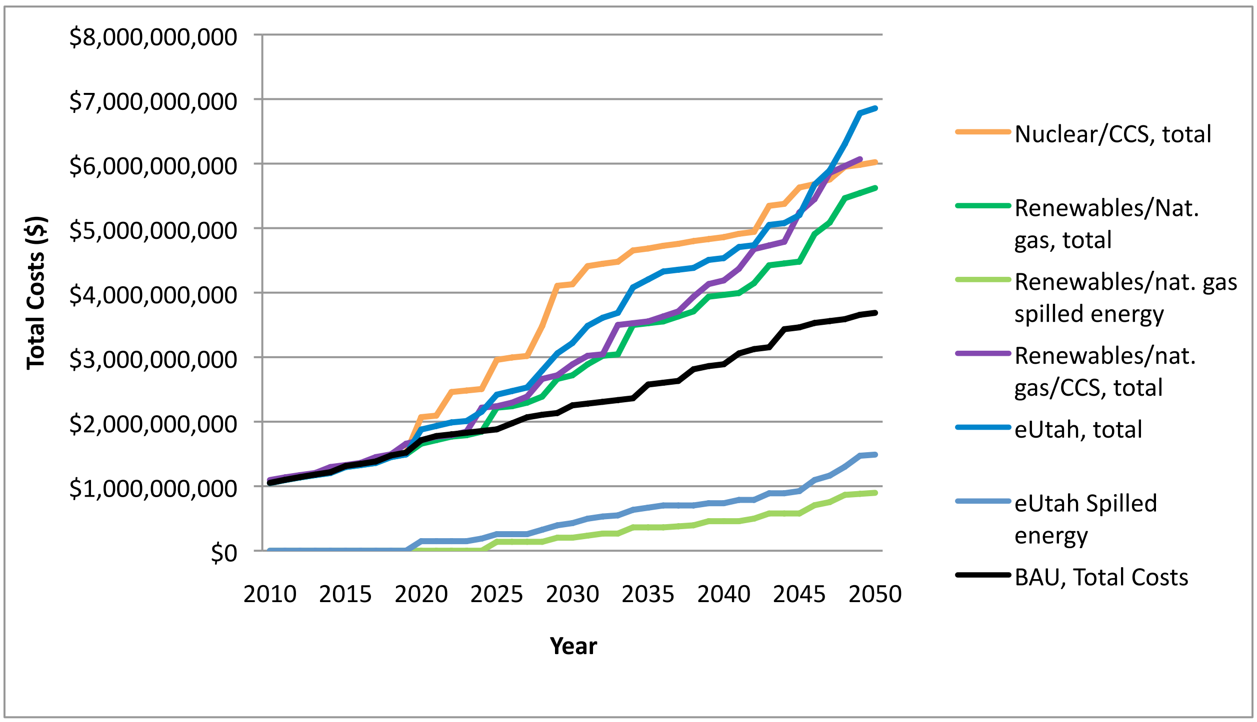

Figure VI-2: Total cost of generation, 2010-2050 in five scenarios, as well as the cost of spilled energy in the renewable scenarios (Renewables/Natural Gas and eUtah)

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.

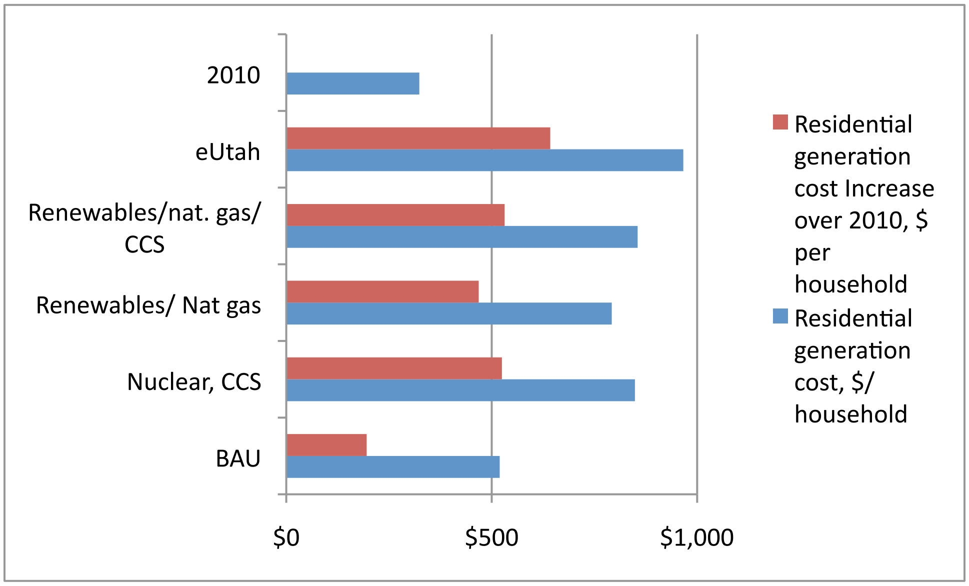

Figure VI-3: Residential electricity costs per household, 2050, with the 2010 cost shown for reference

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

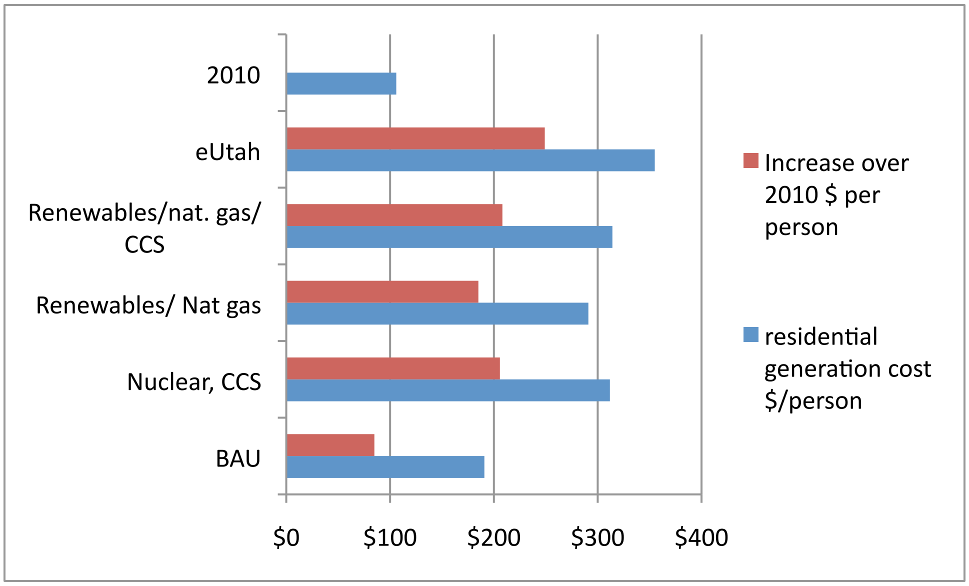

Figure VI-4: Residential electricity generation cost per person, 2050, with the 2010 cost shown for reference.

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.

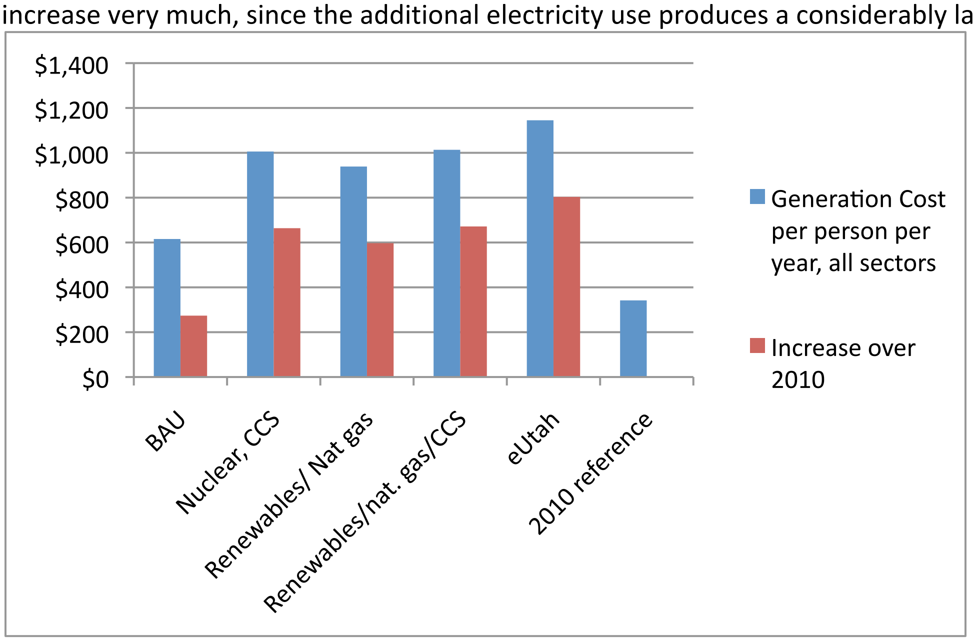

Figure VI-5: Costs of electricity generation per person, 2050, for all sectors of the Utah economy, with the 2010 cost shown for reference

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.

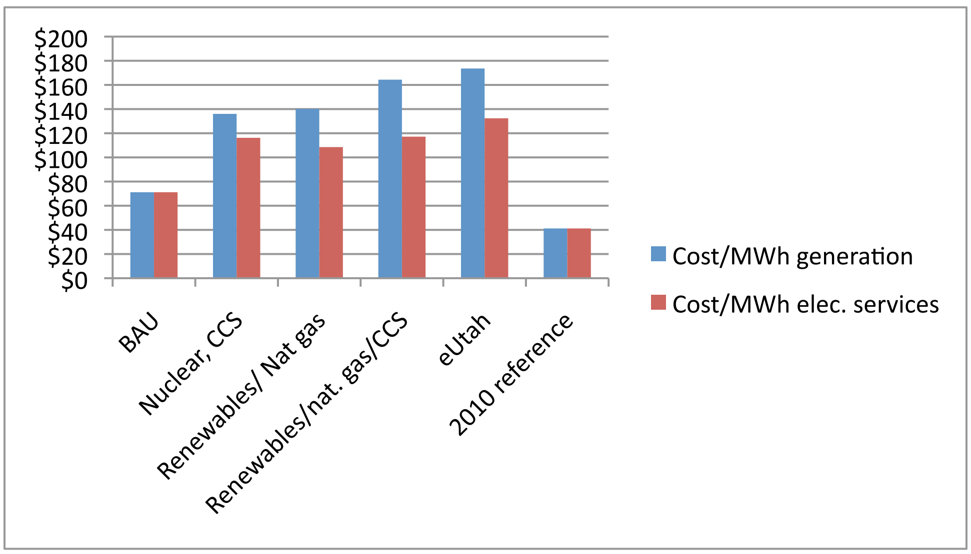

Figure VI-6: Cost per MWh of electricity generation and electricity services in 2050, with the 2010 cost shown for reference

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.

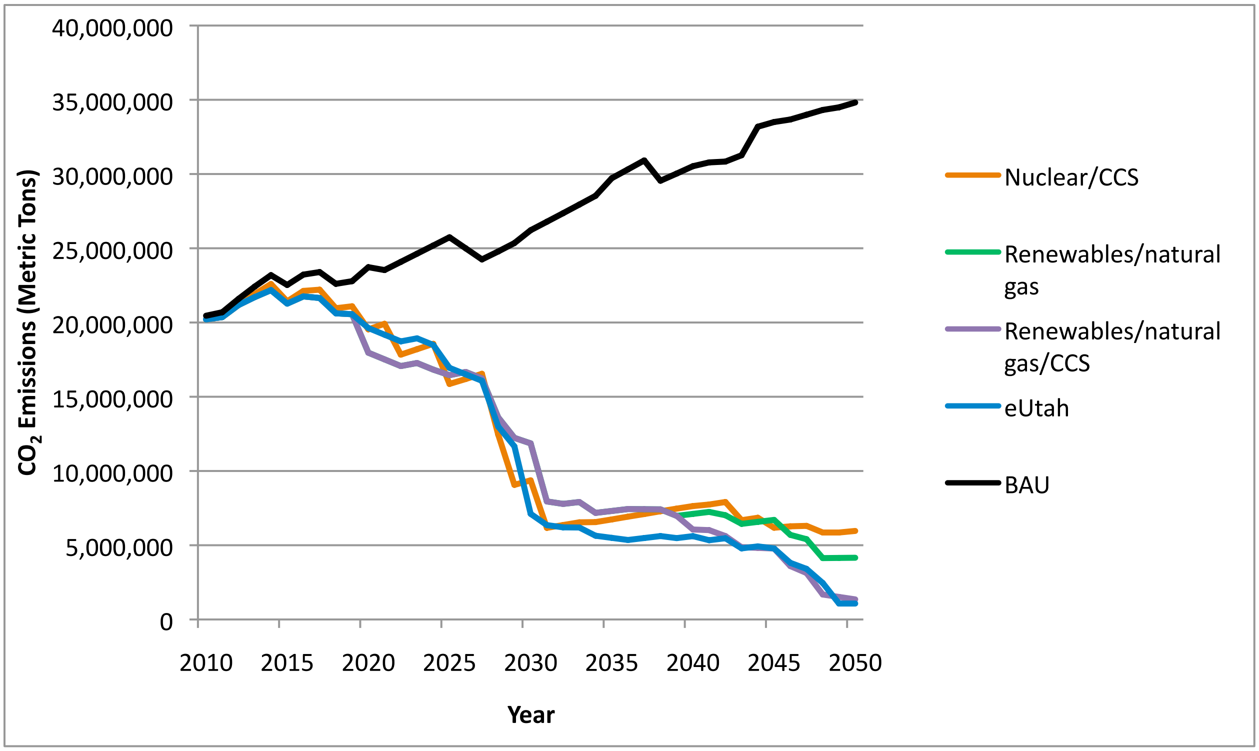

Figure VI-7: CO_2 emissions in the various scenarios. The emissions increase in the BAU scenario, is a result of the fact that carbon is not constrained as part of the BAU scenario design. The jagged curves result, in part, from varying amounts of generation from existing capacity (see text).

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.

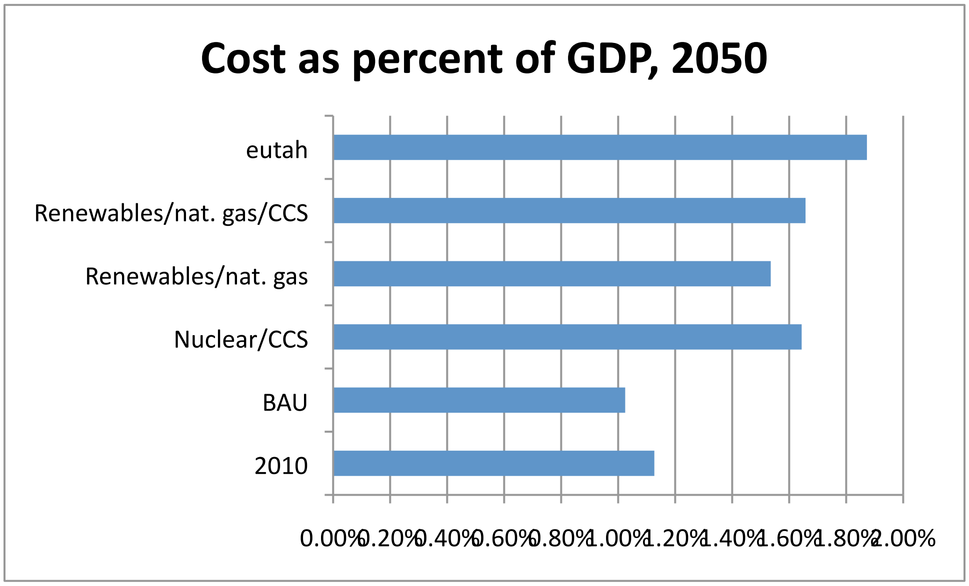

Figure VI-8: Percent of Utah GDP devoted to electricity generation in 2050, with the 2010 value shown for reference.

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.

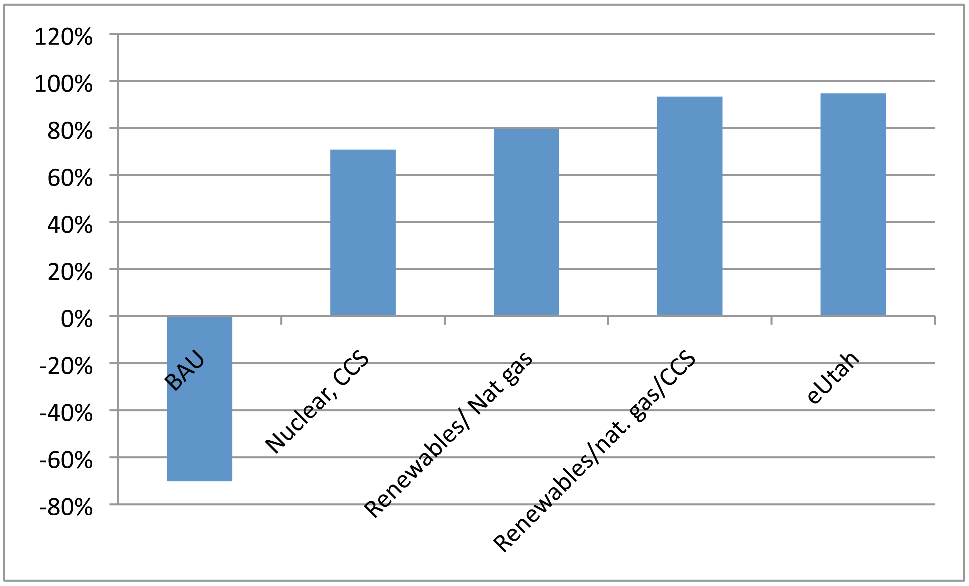

Figure VI-9: CO_2 emissions reductions in the year 2050 relative to 2010 in the various scenarios. The negative number for BAU represents an increase in emissions.

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]

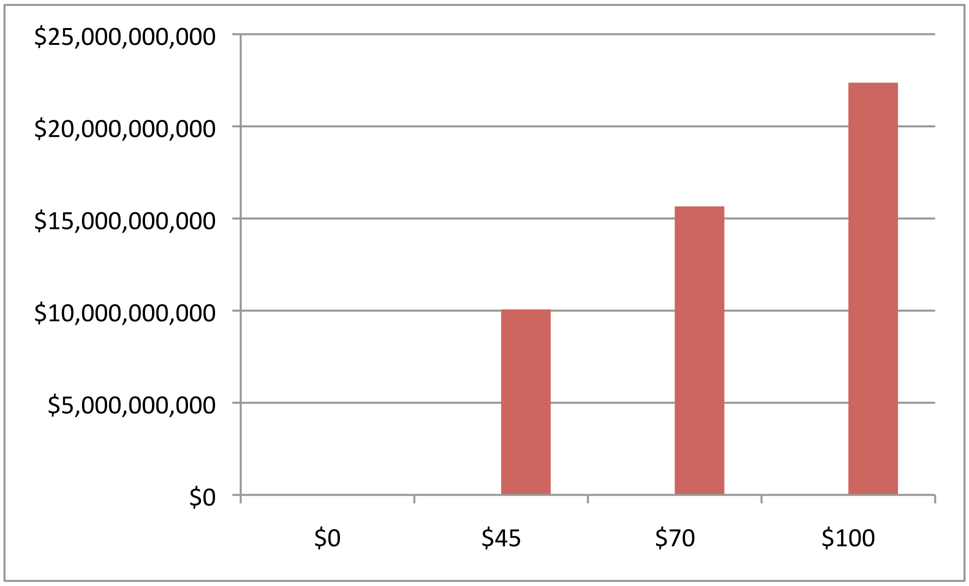

Figure VI-10: Present value in 2010 of carbon costs incurred over the period 2020 to 2050 at various levels of carbon tax

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.

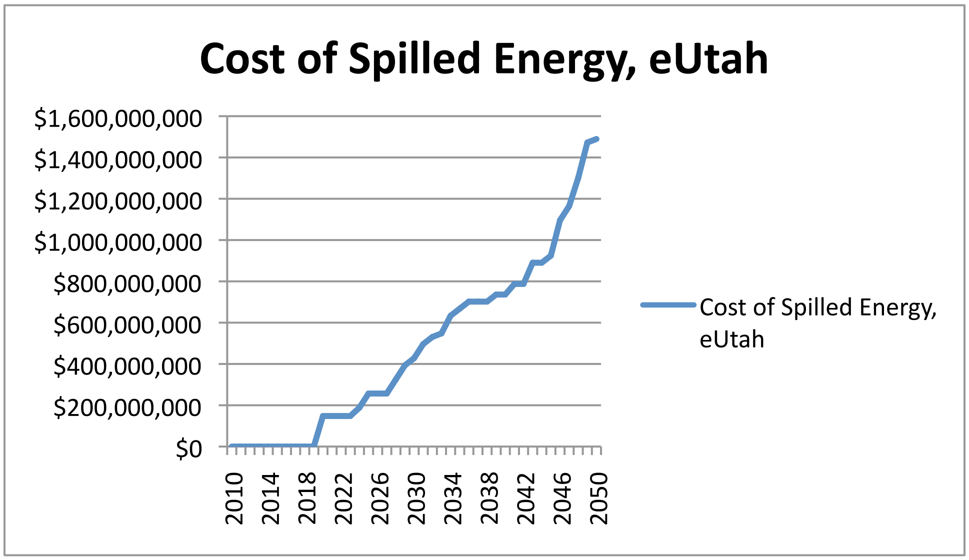

Figure VI-11: Cost of spilled energy in the eUtah scenario from 2010 to 2050, valued at the average cost of solar and wind energy generation

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.

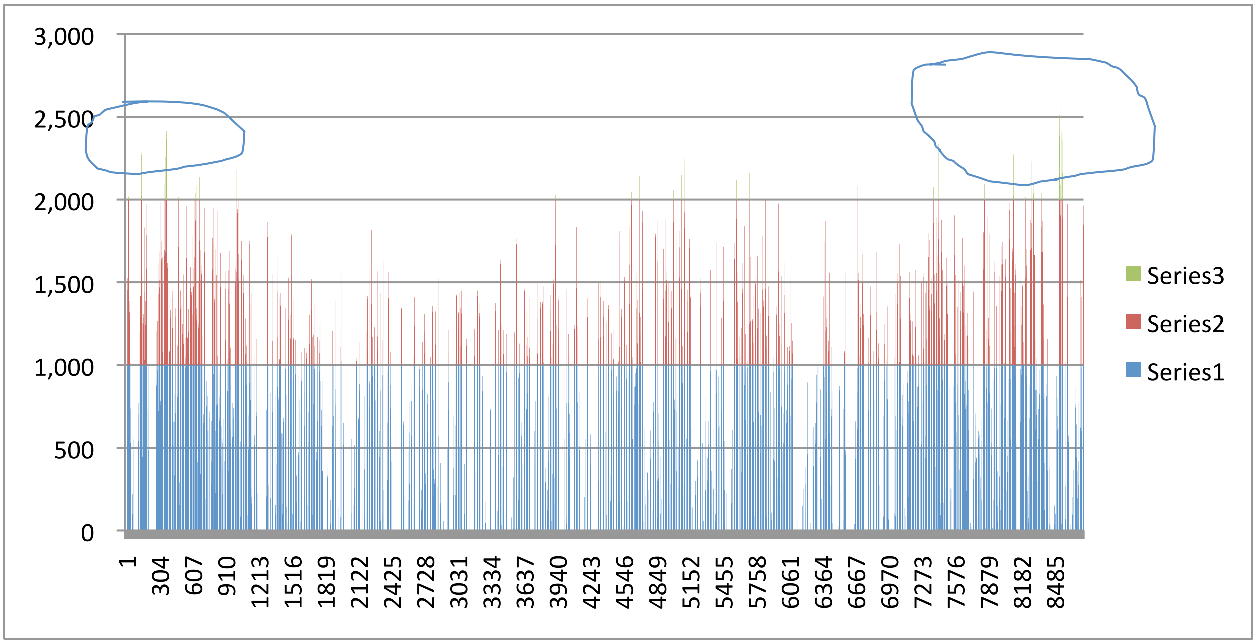

Figure VI-12: Use of expander capacity to generate electricity from storage in the reference year in the eUtah scenario. Series 1: the 1st 1,000 MW of expander, series 2, the next 1,000 MW; series 3 the final tranche. The horizontal axis is hours of the year, starting with the midnight hour on Janurary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

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

[90] Keystone 2007 p. 11

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	$616	$815	$939	$1,013	$1,145

year					
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.

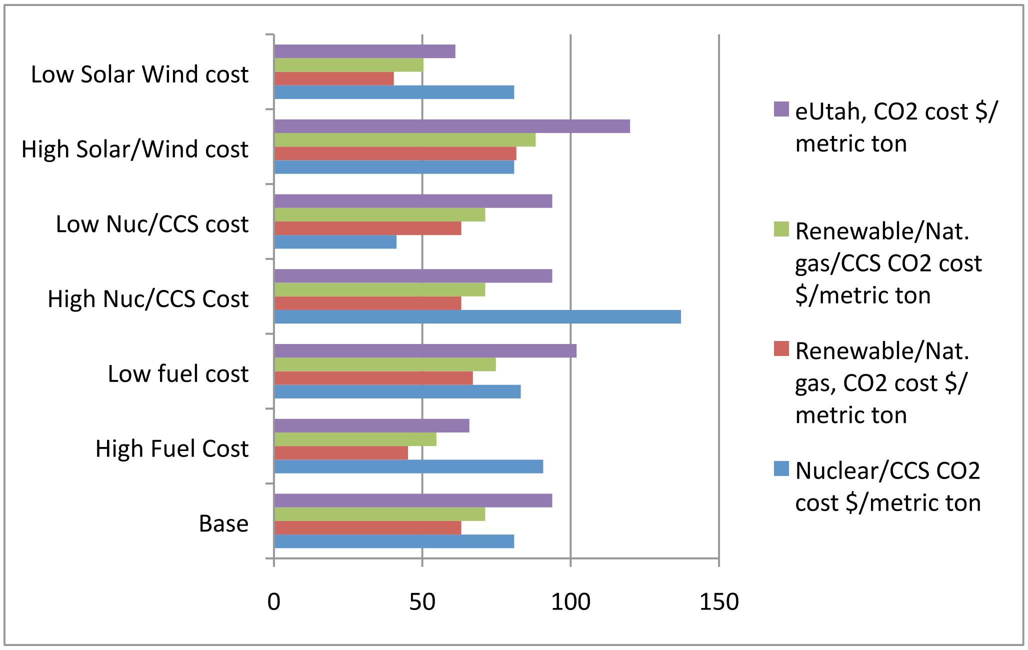

Figure VI-13: CO_2 emissions reduction costs, in dollars per metric ton, shown on the X-axis, under six variations of cost parameters compared to the base case.

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

[91] NREL 2010

supply 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 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

[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

Parabolic Trough with dry cooling	0	80	80

(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.

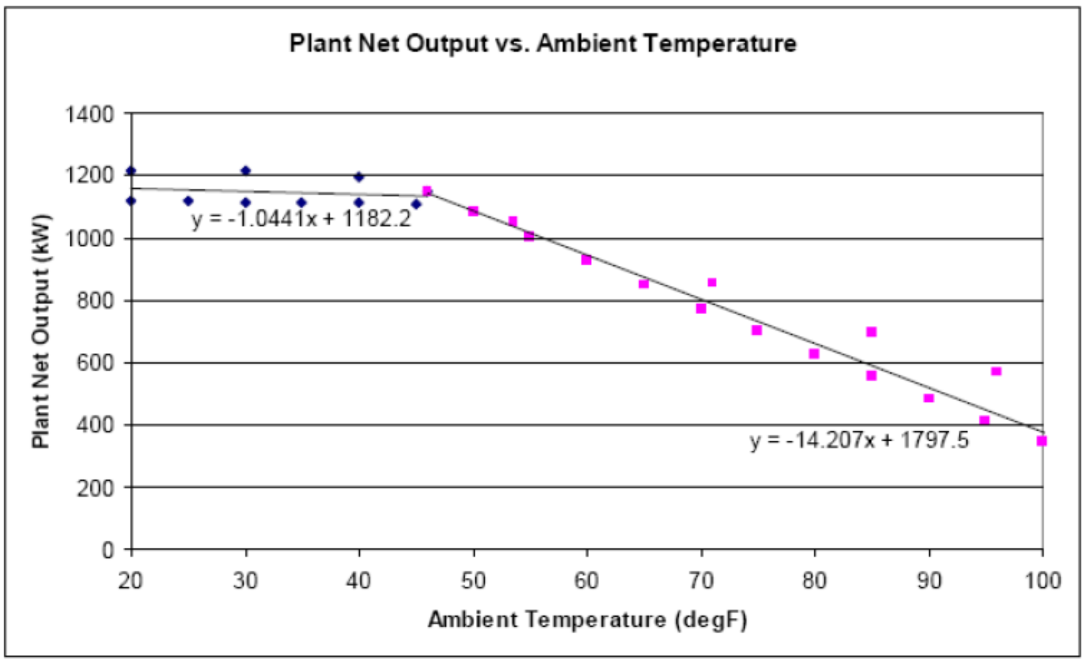

Figure VI-14: Geothermal plant output versus ambient temperature showing drastic loss of capacity at higher temperatures.
Source: UREZ II 2010 p. 4-3

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] 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.

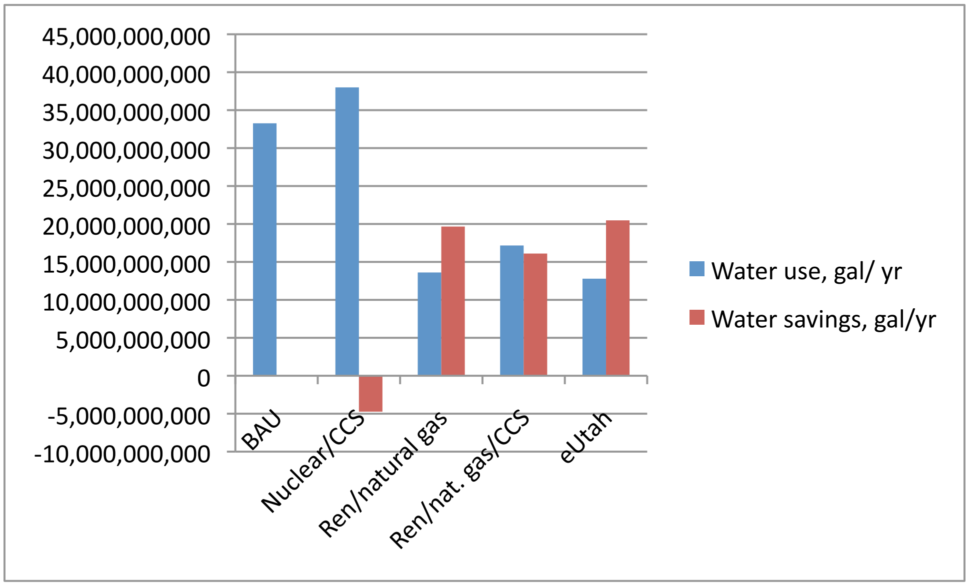

Figure VI-15: Water use in 2050 and savings compared to the BAU scenario, in gallons per year. Water use shown is mainly consumption by evaporation plus some blowdown water for cooling towers.

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.

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

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

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 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

[97] Synapse 2010 p. 4

[98] Utah Energy Initiative Draft 2010 p. 3

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.

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.

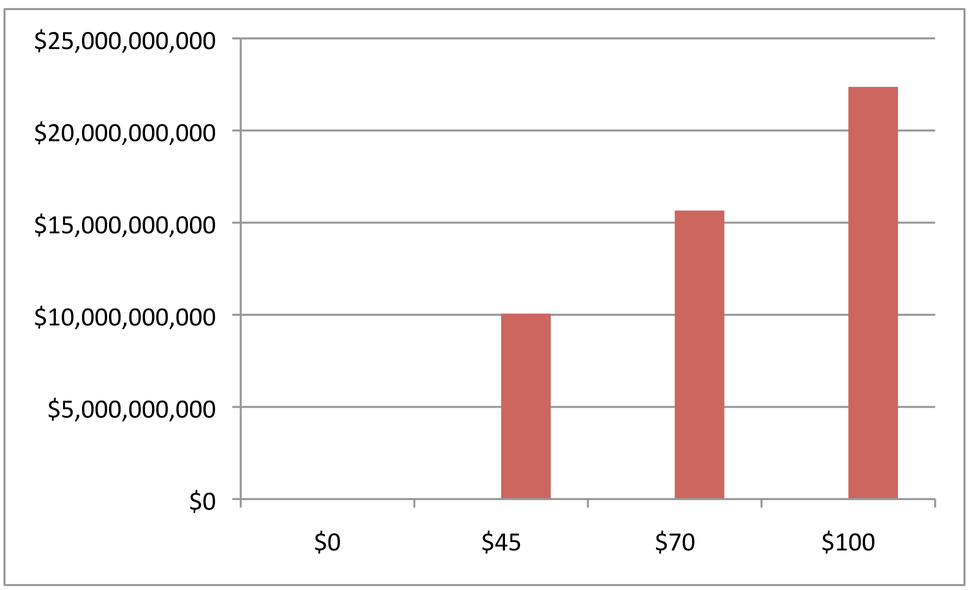

Figure VII-1: Present value, in 2010, of carbon emission costs at four prices for BAU scenario emissions in the 2020 to 2050 period.

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.

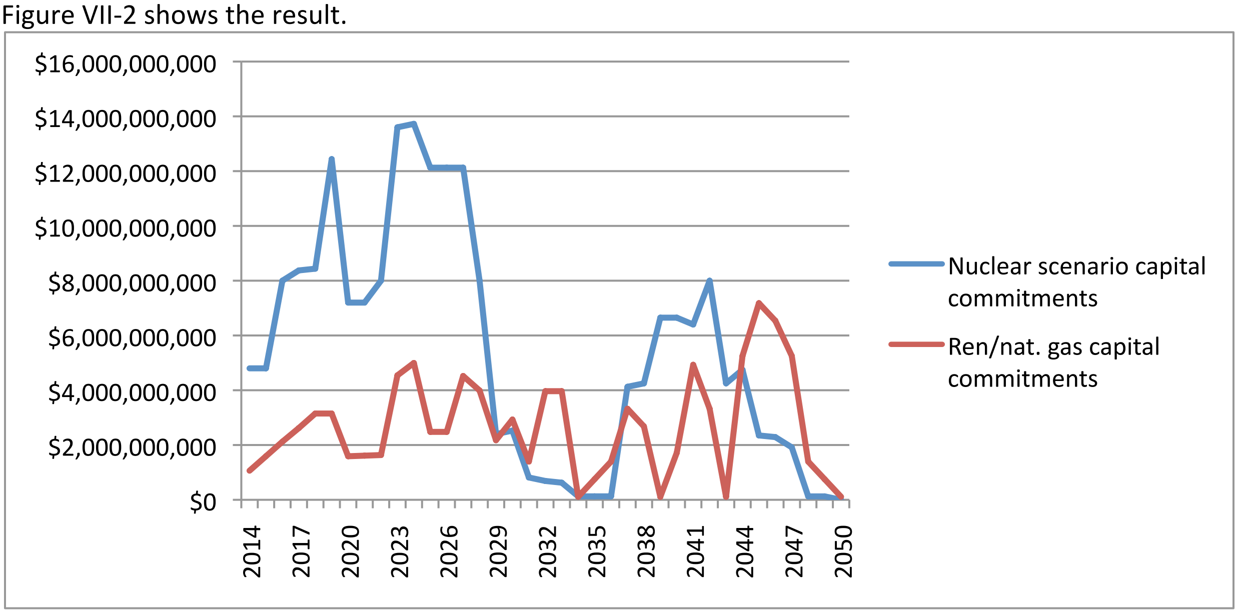

Figure VII-2: Capital commitment in any year in the 2014 to 2050 period in the Nuclear/CCS and Renewables/Natural Gas scenarios.

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

[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.

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.

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

[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

much lower CO_2 emissions than coal, CCS is less expensive with combined cycle power plants than it is with coal.

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

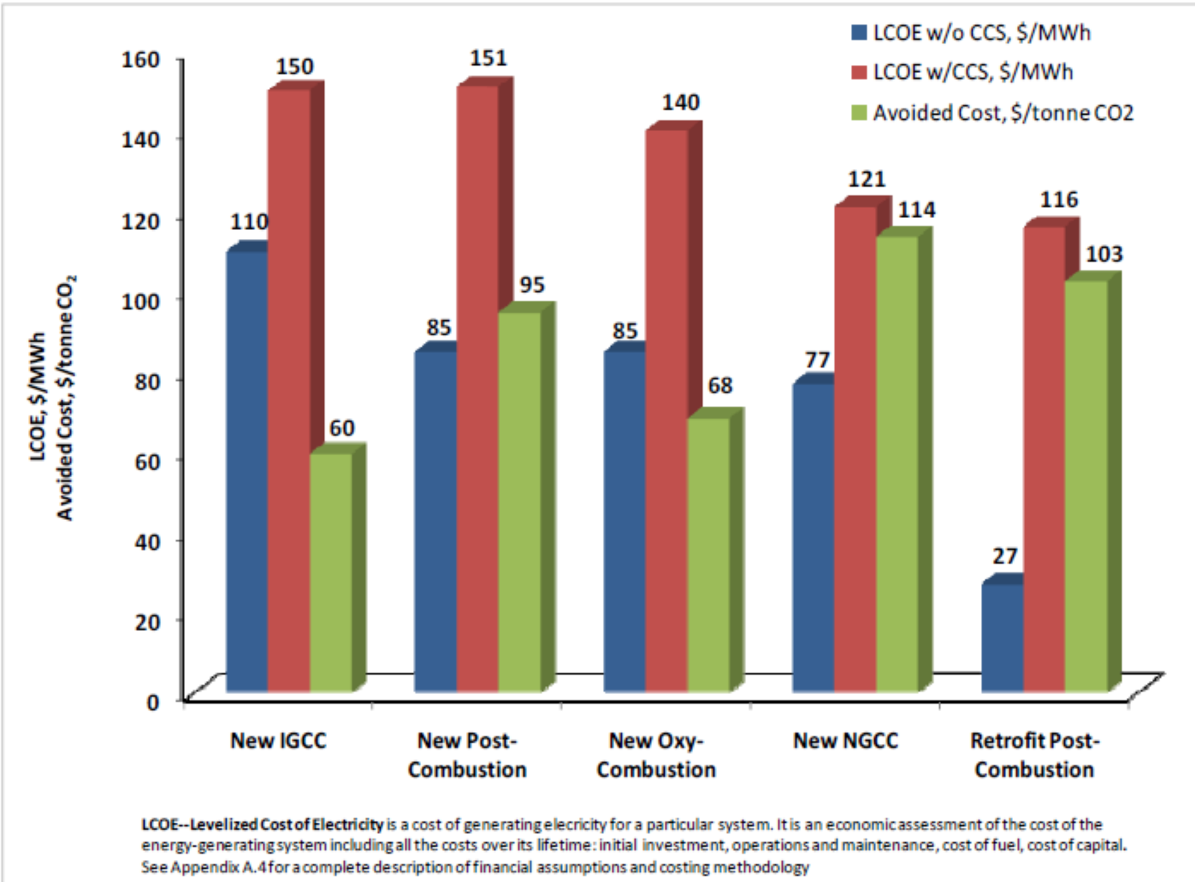

Figure VII-3: Costs of electricity generation with and without CCS for various technologies in new fossil fuel plants. All examples are for coal, except NGCC, which is a "natural gas combined cycle" plant. Source: Interagency Task Force 2010 Figure A-9 (p. A-14)

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.

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[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.

$$E_{z,t} = I_{z,t} A_z e_{UREZ}$$

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.

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[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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