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Energy Economics, Inc.

Co-Benefits of Energy Efficiency and Renewable Energy in Utah

AIR QUALITY, HEALTH, and WATER BENEFITS

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Table of Contents

Utah Disclaimer

The following report was prepared as part of a study to quantify and monetize the co-benefits of energy conservation, energy efficiency, and renewable energy deployment in Utah. The principle funding source was a $150,000 U.S. Department of Energy grant (DF-FG26-07NT43340) awarded in September 2007 to the Utah State Energy Program. Matching funds were provided by the Governor's Energy Advisor and by the Division of Public Utilities. The Office of Consumer Services, State Energy Program, and Division of Air Quality, also provided in-kind support for the project. Collectively, the participating agencies issued a nationwide Request for Proposals seeking a firm to undertake the study. This report is the result of that study.

The participating agencies have monitored and reviewed the project at multiple stages and have provided input and comments about this report. However, this report represents primarily the findings of Synapse Energy Economics, Inc. Its findings and recommendations do not necessarily reflect the positions or policies of any or all of the participating state agencies.

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1. Executive Summary

Synapse Energy Economics, Inc. (Synapse) was contracted by Utah State agencies, including the State Energy Program, the Division of Public Utilities, the Division of Air Quality, the Office of Consumer Services, and the Governor's Energy Advisor (collectively, "Utah Agencies") to develop and apply methods of calculating water and health co-benefits of displacing electricity generation technologies in Utah with new energy efficiency (EE) or renewable energy (RE).

Co-benefits are defined herein as the monetary value of avoided externalities, or the indirect social costs, of energy production. The externalities of power production include both socialized benefits, such as employment opportunities and an increased tax base, as well as significant social and environmental costs, such as health problems, regional haze, and acid rain caused by emissions, as well as the consumption of limited natural resources, including water. Co-benefits are the social and environmental externalities that can be avoided through the implementation of new policies that either displace or replace existing generation. Regulatory mechanisms, such as compelling emissions and/or water controls on existing and new generators, are one method of mitigating external social costs.

According to this and other research, the monetary value of co-benefits and externalities is on the same order of magnitude as the direct costs of energy production (such as capital, fuel, and operational costs) and benefits (such as reliability and availability). These monetizations provide a more comprehensive economic evaluation of existing generation, and of technologies that avoid harmful externalities. Toward this end, Synapse' research establishes and applies a methodology to quantify and monetize two co-benefits of energy efficiency and renewable energy: avoided human health costs and depletion of water resources.

Currently, electricity generation in Utah is almost entirely fired by fossil combustion, and of that, about 82% is fired by coal. This resource mix is relatively inexpensive in direct costs to both Utah and out-of-state consumers, but results in significant emissions of air pollutants and consumes a large share of Utah's increasingly valuable water resources. The authors estimate that fossil generation in Utah today:

- consumes about 73,800 acre feet, or 24 billion gallons, of fresh water per year;
- results in 202 premature deaths per year;
- contributes to 154 hospital visits per year for respiratory injuries, and 175 asthma-related emergency room visits each year.

We estimate that the health and water impacts from Utah fossil generation have a monetary value of between $1.7 and $2.0 billion dollars per year (2008$), or between

$36 and $43 per megawatt-hour (MWh) of fossil generation in Utah, a value similar to the direct costs of conventional electricity generation.[1]

The purpose of this study is to put forth methodologies estimating the co-benefits that can be achieved from renewable energy and energy efficiency. The quantification of these co-benefits, and of the externalities from which they derive, is by no means straightforward, and there are significant assumptions and uncertainties that underlie this study. Some of these uncertainties are:

- The statistical dispatch model relies on limited, public historic generation data to estimate how fossil resources will respond to efficiency and renewable energy (Section 3);
- Emissions of fine primary particulate matter ($PM_{2.5}$) are estimated where reported data are not available, primarily for gas-fired generators (Section 4.2.1);
- Population exposure to $PM_{2.5}$ emissions are based on previous modeling exercises, which carry an intrinsic degree of uncertainty (Section 4.2.2);
- For most gas-fired power plants in Utah, no direct chemistry-transport modeling has been conducted, and therefore this study relies on extrapolations from previously modeled power plants (Section 4.3);
- Ozone exposure modeling is based on a single paper in which relationships were derived for a single summertime month in 1996, and therefore the uncertainties on ozone impacts (morbidity) are likely large and potentially highly biased (Section 4.3);
- Morbidity estimates are based largely on recent peer-reviewed meta-analyses, rather than Utah-specific studies (Section 4.2.3);
- The relationship between population emissions exposure and premature mortality (the concentration-response function) is approximated as linear (Section 4.2.3);
- While this study uses the federally recommended value of $8 million per statistical life. This, economic estimates of the value of a statistical life (VSL) is based on the previously EPA-designated value of $5.5 million (1999$) adjusted to $8 million (2008$). The range of economic estimates of the VSL in EPA's determination ranged widely between $1 and $10 million dollars (1999$) (Section 4.2.5);
- Water use at power plants is inconsistently reported and sparsely available, and therefore this study has estimated water consumption for some power plants based on values from the literature (Section 5.2);

[1] The ranges on the co-benefit and externality values reflect only uncertainties in the externality cost of water consumption, a previously undefined metric which was derived for the purposes of this study. The range indicates neither the uncertainty associated with the impacts of emissions on health, nor does it incorporate the range of published value of statistical life (VSL) measures.

- The externality cost of water is undefined and likely highly variable by region, even within Utah (Section 5.3)

To give a sense of the magnitude of the uncertainties for just some of these estimates, a paper co-authored by one of this study's authors quantified and propagated uncertainties in all aspects of uncertainty modeling.[2] For the coal-fired power plants in Utah, health damages per kWh ranged between 20% of the central estimate (at the 5th percentile) to 250% of the central estimate (at the 95th percentile) represented in this paper.

Most of the externality costs estimated in this study are sourced at coal-fired generators. Reducing the level of in-state coal-fired generation would result in significant benefits for residents of Utah and downwind states. This reduction could occur, in small part, from a reduction in load in Utah, or the integration of new renewable energy onto the grid in Utah and surrounding states. However, Utah is a net electricity exporter in an extensive and highly integrated Western electric grid that extends from the Rocky Mountain States to the Northwest, and from the Northwest down to California. Because of the dynamics of this system, it is unlikely that modest amounts of EE or RE in Utah alone would effectively displace coal-fired generation in Utah. Therefore, the co-benefits from the "passive" integration of EE and RE are modest relative to the externality costs of generation. We estimate that total co-benefits for EE and RE range from a high of $27 per MWh of fossil generation avoided, when wind or solar photovoltaics are employed, to a low of a *cost* of $4 per MWh, when high water-use concentrating solar thermal systems are employed.

By way of contrast, an active replacement of the least efficient power plants in Utah with energy efficiency and either gas generation or renewable energy results in very high co-benefits to the state. We find that for each MWh of coal generation avoided, Utah avoids $69 - $79 of externality cost, a benefit that exceeds the cost of most electrical generation.

This analysis examines the marginal health and water benefits from modest amounts of energy efficiency and renewable energy in Utah. It does not examine the benefits that could be realized from a market transformation in the West, with significant penetrations of new renewable energy, dramatic load reductions, or a price on greenhouse gas emissions.

1.1. Approach

In this study, calculating co-benefits entails four processes. First, we must determine which conventional resources are likely to be displaced, replaced, or avoided by EE and RE. Second, we must establish the health and water impacts that are avoided by displacing conventional generation. Third, a monetary value must be ascribed to these physical externalities. Finally, we present the co-benefit cost-effectiveness of EE and RE

[2] Levy, J.I.; Baxter, L.K.; Schwartz, J. Uncertainty and variability in health-related damages from coal-fired power plants in the United States. *Risk Analysis*. **2009**, 29(7) 1000-1014.

as the value saved for every unit of conventional energy avoided. Applied in this research, co-benefits are estimated as the difference in externality costs between a baseline (business-as-usual) future versus alternative scenarios with new investments in energy efficiency, renewable energy, or a proactive replacement of existing generators.

Synapse analyzed a range of feasible energy efficiency and renewable energy options to assess their potential in realizing health and water co-benefits. These scenarios are organized into four over-arching categories, including:

1. **Baseline**, in which load growth continues unabated and new in-state demand is met with gas generators; [3]
2. **Energy efficiency and demand response**, ranging from modest reductions of 1% per year relative to baseline load growth, to more aggressive targets of 3% per year by 2020;
3. **Renewable energy**, including wind at any of three locations (Porcupine Ridge, TAD North, and Medicine Bow, Wyoming), two photovoltaic options (flat plate and tracking), two concentrating solar thermal projects (parabolic trough and a solar tower), and geothermal operations; and
4. **Replacement** of selected inefficient and aging coal generators with either energy efficiency and new combined cycle gas, or energy efficiency and a combination of renewable energy projects

We compare the projected 2020-21 generation and emissions from each of the alternative scenarios to the projected baseline generation and emissions using a load-based probabilistic emissions model, described in Chapter 3. This model, which is based on statistical analysis of 2007-2008 generation and emissions data from the US EPA's continuous emissions monitoring (CEM) program, was developed by Synapse to determine the emissions benefits of replacing conventional generation with emissions-free resources. Once the generation and emissions for each scenario have been determined, we estimate water and health impacts for each scenario, including water use, mortality, and morbidity, relative to the baseline. We also estimate some aspects of lost productivity, including restricted activity days and lost school days. The externality costs are calculated based on the physical impacts (mortality, morbidity, and water use).

In addition to producing carbon dioxide (CO_2) that has been linked to climate change, the combustion of fossil fuels results in the emission of pollutants such as nitrous oxides (NO_X), sulfur dioxide (SO_2), and fine particulates, and in some cases mercury, all of which are harmful to human health. We use an independent modeling framework to estimate the downwind chemical and particulate impacts, as well as resulting premature deaths (mortality), hospitalizations for respiratory and cardiac illnesses and asthma (morbidity), and lost productivity.

[3] Load growth is estimated from data provided in 2008 by PacifiCorp, a western utility serving over 88% of Utah generation.

A value of statistical life (VSL) is used to assign monetary values to health outcomes, reflecting a societal willingness-to-pay to avoid adverse health effects. The VSL used in this study is not an explicit recommendation. Numerous studies have attempted to derive a VSL, with estimates ranging from under $1 million to over $10 million per statistical life, as noted above. Based on an EPA's recommended value of $5.5 million (in 1999$), this study used a time-adjusted VSL of approximately $8 million. The method used here has been widely applied, and is endorsed by the EPA Science Advisory Board, the US Office of Management and Budget, and the National Academy of Sciences, amongst others.

The water-related externality cost is derived from the consumption of water by thermal generators (both fossil and renewable), and the estimated marginal cost of water in Utah. Thermal generators use water for boilers, cooling, and emissions controls. In this study, we track consumptive (non-recycled) water use for cooling purposes, based on the historical rate of water consumption for individual fossil generators in the state. We estimate a range of social values for water in Utah based on recent water-rights transactions. We estimate that, in general, Utahns are willing to pay between $520 and $5,182 per acre-foot, or 0.16 to 1.59 cents per gallon for water rights (2008$). Fresh water consumed by power plants that could otherwise be used for other purposes costs the state $38-$383 million per year today.

1.2. Summary of Results

1.2.1. Externalities

In a business-as-usual baseline scenario, we project 279 premature deaths per year by 2020 associated with electric generation impacts, compared to 202 premature deaths in the the reference year, an increase primarily due to population growth.[4] We further project nearly a 25%-45% increase over the baseline year in hospital admissions and ER visits per per year associated with electric generation impacts. However, we estimate that water consumption for generation will grow only moderately, to 77,400 acre feet per year (a 5% 5% increase) due to increasing gas use and only moderate increases in existing coal-fired fired generation (see

Table 1-1).

The energy efficiency and renewable energy scenarios reduce externalities only moderately relative to the baseline. Clean energy programs in Utah would tend to primarily displace gas generation, and do not result in significant externality savings. According to our analysis, significant co-benefits would accrue only when older, inefficient coal units are retired and replaced with energy efficiency programs, renewable enegy and gas-fired generating units.

[4] Approximately 86% of these deaths occur in downwind states from particulates and pollution emitted from generators in Utah. Breakdowns between Utah and out-of state externalities are given in Table 7-2.

Table 1-1: Physical externalities from baseline and scenarios in 2020-2021

	Health Externalities				Water Use, Acre Feet per Year
2007-2008	Statistical Deaths per Year	Cardiovascular Hospital Admissions per Year	Respiratory Hospital Admissions per Year	Emergency Room Visits per Year	
Reference Case	202	21	154	175	73,800
2020-2021					
			Baseline Scenario		
Baseline Load Growth	279	32	194	225	77,400
			Energy Efficiency Scenarios		
EE (SWEEP)	277	31	193	224	75,900
EE (2% per yr)	274	31	192	223	75,800
EE (3% per year)	267	30	186	216	72,400
			Renewable Scenarios		
Wind (Porcupine)	273	31	189	220	74,400
Wind (TAD North)	271	31	187	218	74,000
Wind (Medicine Bow)	271	31	187	218	73,900
Solar (Flat Plate PV)	276	31	191	222	75,900
Solar (One-Axis Track)	275	31	190	221	75,500
Solar (CSP Trough, Wet Cooled)	277	31	192	224	82,700
Solar (CSP Trough, Dry Cooled)	277	31	192	224	76,500
Geothermal	269	31	186	217	89,600
			Replacement Scenarios		
Replace Coal w/ EE and Gas	182	20	137	157	57,300
Replace Coal w/ EE and RE	178	20	136	155	56,200

In this research, mortality, morbidity, and water consumption are monetized to obtain an externality cost for the reference case (2007-2008), a business-as-usual baseline scenario, and the EE and RE scenarios. We find that fossil-fired generators in Utah result in $1.6 billion (2008$) of health-based damages, and consume between $38-383 million of water. On a per unit energy basis, externalities cost between $36 and $43 per MWh today.

Synapse was not contracted to estimate damages or externalities associated with the emissions of greenhouse gasses, such as carbon dioxide (CO_2). However, other research has evaluated the extent of potential damages occurring from climate change and estimated a range of costs attributable to climate change associated with each ton of CO_2 emissions. If the externality cost of CO_2 were included at a cost of $80 per ton of CO_2, the externality cost of greenhouse gas emissions from power generation in Utah today would be approximately $3.4 billion (2008$), or $72 per MWh of conventional generation.

1.2.2. Co-Benefits

To monetize the estimated co-benefits of avoided fossil generation in Utah, we have calculated expected externality savings, relative to the baseline scenario, in dollars per unit energy of avoided generation. The most significant cost savings from a co-benefit perspective are in avoided mortality, followed by avoided water and morbidity (Table 1-2).

Table 1-2: Monetary co-benefits in dollars per avoided MWh of generation in 2020-2021.

2020-2021	Health Co-Benefits 2008$ / MWh **All** (in Utah) Mortality		Morbidity		Avoided Cost of Water 2008$ / MWh (Low - High)	Total Co-Benefit 2008$ / MWh (Low - High)
			Efficiency Scenarios			
EE (SWEEP)	**$5.6**	($1.5)	**$0.1**	$0.0	**$0.2 - $2.1**	**$5.9 - $7.8**
EE (2% per yr)	**$7.8**	($1.7)	**$0.1**	$0.0	**$0.1 - $1.4**	**$8.0 - $9.3**
EE (3% per year)	**$12.3**	($2.8)	**$0.2**	$0.1	**$0.3 - $3.1**	**$12.8 - $15.6**
			Renewable Scenarios			
Wind (Porcupine)	**$18.6**	($4.5)	**$0.4**	$0.2	**$0.5 - $5.5**	**$19.5 - $24.4**
Wind (TAD North)	**$20.4**	($4.5)	**$0.5**	$0.2	**$0.6 - $5.5**	**$21.4 - $26.3**
Wind (Medicine Bow)	**$18.9**	($4.4)	**$0.4**	$0.2	**$0.5 - $5.2**	**$19.8 - $24.5**
Solar (Flat Plate PV)	**$19.0**	($4.9)	**$0.4**	$0.2	**$0.6 - $5.5**	**$20.0 - $25.0**
Solar (One-Axis Track)	**$20.7**	($5.0)	**$0.4**	$0.2	**$0.5 - $5.5**	**$21.7 - $26.6**
Solar (CSP Trough, Wet Cooled)	**$7.7**	($2.6)	**$0.1**	$0.1	**-$12.0 - -$1.2**	**-$4.2 - $6.6**
Solar (CSP Trough, Dry Cooled)	**$7.7**	($2.6)	**$0.1**	$0.1	**$0.2 - $2.0**	**$8.0 - $9.8**
Geothermal	**$19.8**	($4.6)	**$0.4**	$0.2	**-$15.6 - -$1.6**	**$4.6 - $18.7**
			Replacement Scenarios*			
Replace Coal w/ EE and Gas	**$67.26**	($7.39)	**$1.00**	($0.48)	**$0.9 - $8.7**	**$69.1 - $76.9**
Replace Coal w/ EE and RE	**$68.94**	($7.79)	**$1.00**	($0.48)	**$0.9 - $9.0**	**$70.8 - $78.9**

*The replacement scenarios estimate co-benefits against is avoided *coal* generation. These values are not directly comparable to the other scenarios

We find that reducing energy consumption through energy efficiency measures results in savings of between $6 to $16 per MWh of conventional generation displaced. In the renewable energy scenarios, we find total co-benefits range from a *cost* of $4 per MWh to a savings of $27 per MWh.

To achieve even more dramatic co-benefits, if approximately one-third of Utah's most inefficient and polluting coal generators are replaced with a rigorous energy efficiency program and either gas or renewable energy, externalities amounting to $70 - $79 could be realized for each MWh of coal retired or displaced.[5]

1.3. Policy Implications

Externalities are costs that have an impact on society but that are not included (internalized) in the direct cost to the producer of a good or service. In the case of electric power generation, the externalities explored here are the costs of mortality, morbidity, and depletion of water resources as experienced in Utah and downwind – costs that are imposed upon society but are borne incompletely or not at all by the

[5] These last two scenarios cannot be considered on the same scale as the other EE and RE scenarios because the denominator (MWh of generation avoided) is different. Because externalities from coal-fired generation are far higher than those from gas-fired generation, simply replacing coal generation with gas reduces the externality cost significantly, but does not avoid fossil generation. Estimated as a co-benefit, this calculation would result in unreasonably high co-benefits per MWh avoided.

owners or operators of the generating plants. Avoiding these “indirect” costs represents a co-benefit to the state, as well as for neighboring states. This co-benefit is additional to the direct benefits of avoided fuel consumption, operating costs, and the need for new generation and transmission.

In this research, we find that the externality cost of fossil fuel combustion for electricity is expensive, comparable in magnitude to the total direct cost of conventional generation. However, we conclude that newn energy efficiency and renewable energy programs in Utah can achieve relatively modest externality savings. This is because efficiency and renewable energy in Utah primarily displaces natural gas-fired energy and imported hydroelectric capacity, rather than coal. As a theoretical bookend, we find that replacing older, inefficient generators with efficiency and low-emissions units results in a dramatic reduction in externality costs.

Another approach that is likely to achieve significant societal benefits in Utah, not quantified in this research, is to reduce energy consumption requirements throughout the Western United States. Utah is an electricity exporting state in a tightly interconnected regional grid; reducing regional power requirements or introducing a high penetration of renewables throughout the region could result in avoided generation in the region and significant water and health benefits in Utah. Coalitions such as the Western Regional Air Partnership (WRAP) or the Western Climate Initiative (WCI) provide opportunities to influence regional demand that affects Utah. Without integrated regional approaches, EE and RE are unlikely to produce significant co-benefits in Utah.

Modeling emissions avoidance, externalities, and co-benefits can be useful for planning and licensing purposes. The results of this study may be used in state processes for considering the full costs and benefits of new generators in utility integrated resource plans (IRPs), determining effective strategies to comply with federal or regional air quality plans and state implementation plans (SIPs), estimating pathways to meet emissions targets for regional and federal regulations, calculating benefits of state, regional, or federal renewable portfolio standards, and examining indirect costs and benefits of transmission expansion plans. This approach can help lead to resource planning and policy decisions that better reflect the interests of Utah and its residents.

2. Introduction and Scope

Energy efficiency (EE) and renewable energy (RE) both decrease dependences on fossil fuels and reduce harmful emissions and environmental impacts from energy production. Meeting energy requirements by improving end-use efficiency has the joint benefit of moderating energy costs, while also trimming "criteria" and greenhouse gas emissions and reducing water consumption at fossil power plants. New renewable energy projects can serve to displace existing fossil generation, also lessening emissions and water consumption. These reductions improve public health, increase water availability for other uses and ecosystems, and reduce the risk of climate change. The monetary values of these benefits, known as co-benefits, are not often considered in energy resource plans, but could have significant impacts if the social costs of damaged human health or water consumption were considered.

This study focuses on the health and water co-benefits of efficiency and renewable energy to more thoroughly examine the costs and benefits of alternative energy supply. Turning to EE and RE is rapidly becoming a mainstream mechanism to achieve emissions reductions and other environmental benefits. For example, the US Environmental Protection Agency (EPA) allows states to reward select EE and RE projects with emissions allowances as an option to meet air quality goals.[6] A number of states have implemented EE and RE "set-asides" for EPA mandated emissions reductions. In these states, a portion of emissions reductions may be met through efficiency and renewable energy programs. Such states include Connecticut,[7] the District of Columbia, Delaware, Illinois,[8] Indiana,[9] Massachusetts,[10] Maryland, Michigan, Missouri,[11] New Jersey,[12] New York,[13] Ohio, Pennsylvania, Virginia, Wisconsin, and Texas.[14] Increasingly, state and proposed federal renewable portfolio standards[15] are designed to reduce emissions.

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6 US EPA.

7 Application for CAIR Energy Efficiency and Renewable Energy Set-Aside (EERESA) NOx Allowances. 2009. http://www.ct.gov/dep/cwp/view.asp?a=2684&Q=432654&depNav_GID=1619

8 Emissions Impact of the Sustainable Energy Plan for Illinois. 2007. http://www.illinoisbiz.biz/NR/rdonlyres/BECFB4FB-B5AA-4874-B353-85E879A11BA0/0/092007ILEmissionsImpactRptJUL07.pdf

9 Indiana NOx Budget Trading Program. 2003. http://www.in.gov/idem/files/EE_REguide2.PDF

10 State Set-Aside Programs for Energy Efficiency and Renewable Energy Projects Under the NOx Budget Trading Program: A Review of Programs in Indiana, Maryland, Massachusetts, Missouri, New Jersey, New York, and Ohio. 2005. http://www.epa.gov/RDEE/documents/eere_rpt.pdf

11 Missouri (http://www.dnr.mo.gov/pubs/pub2234.pdf),

12 New Jersey – A Leader in Fighting Pollution. Federal-state partnership to improve air quality benefits from clean energy projects. 2008. http://www.nrel.gov/docs/fy08osti/41173.pdf

13 New York (http://www.nyserda.org/cair/documents/CAIR%20Plan.pdf)

14 Reducing Emissions Using Energy Efficiency and Renewable Energy. Texas Comission on Environmental Quality. 2008. http://www.tceq.state.tx.us/implementation/air/sip/eere.html

15 H.R. 2454--111th Congress: American Clean Energy and Security Act of 2009. (2009). In GovTrack.us (database of federal legislation). Retrieved Nov 18, 2009, from http://www.govtrack.us/congress/bill.xpd?bill=h111-2454

The Utah Agencies requested a report that develops methods of quantifying and valuing health and water co-benefits of EE and RE implemented within the state.[16] This report is designed to help State agencies establish quantitative metrics to inform state policy. Specifically, State agencies are interested in understanding the costs of uncontrolled and/or fugitive emissions from traditional sources within the state that could lead to undervaluing renewable energy, energy efficiency, and/or energy conservation programs meant to supplement, displace, or replace traditional generation.

2.1. Co-Benefits and Externalities, Direct and Indirect Costs

Externalities are defined by the National Academy of Sciences as "activit[ies] of one agent (i.e., an individual or an organization like a company) that affect the wellbeing of another agent and occur outside the market mechanism."[17] External costs and benefits are imposed upon society and are external to the costs experienced by generation owners or utility ratepayers.[18] In this research, externalities are specifically negative impacts. The co-benefits of alternative energy programs are defined here as the benefits accrued to society by avoiding negative externalities associated with energy production. These benefits are distinct from the direct, internalized costs and benefits of energy production: direct, internalized costs are met by ratepayers, while external, indirect costs and benefits are faced by society at large.

[16] "Consideration of environmental externalities and attendant costs must be included in the integrated resource planning analysis. The IRP analysis should include a range, rather than attempts at precise quantification, of estimated external costs which may be intangible, in order to show how explicit consideration of them might affect selection of resource options." Utah Docket 90-2035-01 (1992).

[17] National Academy of Sciences. Hidden Costs of Energy: *Unpriced Consequences of Energy Production and Use.* Committee on Health, Environmental, and Other External Costs and Benefits of Energy Production and Consumption; National Research Council. National Academies Press, 2009.

[18] In this research, we define "costs" as expenditures or losses, and "benefits" as improvements in wellbeing (monetary or otherwise) and costs avoided.

Certain costs are traditionally estimated for the purposes of planning and rate-making, while other costs are not usually considered. In most cases, only the direct costs and benefits are internalized as costs to ratepayers. Examples of direct and indirect costs and benefits are characterized in Table 2-1.

Table 2-1: Examples of direct and indirect costs and benefits of power generation

	Direct Costs and Benefits	Indirect Costs and Benefits
Typically considered in planning [19]	- Capital and infrastructure - Fuel - Operations and maintenance (O&M) - Transmission requirements - Capacity and reliability - Environmental regulation compliance	- Employment - Tax basis - Future environmental regulation compliance [a]
Typically not considered in planning	- Downstream economic impacts - Economic multiplier effects - Demand response impact price effect	- Health impacts - Water consumption - Environmental degradation (land use, haze and visibility, ecosystem impacts) - Waste storage / disposal - Upstream environmental impacts (extraction, processing, and transportation)

[a] Future environmental regulations include the risk or probability that regulations will restrict future activities or increase the cost of operations.

In this analysis, co-benefits are estimated as the monetized value of the social externality costs of generation that are avoided by renewable energy or efficiency, on an energy unit basis (i.e. $/MWh). Each unit of fossil generation avoided reduces a social cost (health, premature deaths, and water consumption), yet not all displaced MWh of fossil generation are equally harmful. Co-benefits measure the value of the harm of each MWh avoided by using EE or RE.

By monetizing these impacts, externalities can be considered on a similar scale with direct costs and benefits. In Utah, the direct application of this exercise is in the valuation of least cost resources for utility integrated resource plans (IRP), resource acquisition approval processes, and demand-side management program approval and review.

2.2. Report Approach and Organization

Establishing the monetary value of the co-benefits of efficiency and renewable energy programs requires several distinct steps. First, we must determine which conventional resources are likely to be displaced, replaced, or avoided by EE and RE. Second, we must establish the impacts that are avoided by displacing conventional generation.

[19] "Considered in planning" is the typical case; some states and utilities consider other costs and benefits as well.

Third, a monetary value must be ascribed to these physical externality impacts. Finally, we present the co-benefit cost-effectiveness of EE and RE as the value saved for every unit of conventional energy avoided. The merit of this presentation is that different EE and RE pathways may be evaluated on a similar basis to standard costs and benefits, given here in constant dollars per megawatt-hour.

In this paper, we estimate the physical and monetary externalities of a baseline scenario, as well as thirteen alternative scenarios, including moderate penetrations of wind, solar, geothermal, and efficiency technologies on the existing electrical grid. The physical and monetary co-benefits are calculated as the difference between the baseline scenario and each of the alternative scenarios.

We do not estimate the direct costs (capital, fuel, or O&M) of new generation or transmission, nor do we estimate the direct costs of energy efficiency programs, or avoided costs of saved fuel, operations, or new infrastructure. Both EE and RE programs are assumed achieve moderate penetrations in Utah, and do not account for large-scale market or technological transformations or new environmental control technologies on existing conventional facilities. The scope of this report is to quantify the physical and monetary co-benefit value of EE and RE programs relative to the existing, or foreseeable future, grid.

The baseline scenario assumes that state energy demands grow according to utility forecasts, and new demands for energy and capacity are met through new gas-fired generators, a relatively conservative approach that assumes a state or federal interest in a low emissions future. To calculate the conventional generation and emissions avoided by EE and RE programs, we create a series of scenarios, organized into four over-arching categories: a baseline (described above), energy efficiency at three levels of penetration, eight renewable energy scenarios, and two auxiliary scenarios exploring the impact of replacing one-third of the most inefficient generation in Utah with energy efficiency and new gas generators or a mixed portfolio of renewable energy.

In each of the scenarios, we run a statistical model designed to estimate the expected hourly generation and emissions from each of Utah's fossil generators both now and in the future, given load growth over time. We create hourly load profiles for potential near term efficiency and renewable options, and impose these profiles on hourly demand, assuming the new resources are non-dispatchable.[20] The statistical model, described in Chapter 3 and Appendix D returns estimated generation and emissions from each of Utah's fossil generators, which are then used to calculate health and water impacts. The model is calibrated with data from a reference year (2007-2008) and run to 2020-2021.

This study estimates health impacts, including mortality, morbidity, and reduced productivity, using an EPA-standard model. We use a source-receptor matrix method to estimate how emissions of oxides of nitrogen (NO_X), sulfur dioxide (SO_2), and

[20] Solar and wind resources do not generate on demand, and therefore either run and displace fossil or hydroelectric resources, or must be curtailed. Therefore, the demand profile that must be met by conventional resources is demand less the energy produced by renewables or reduced by energy efficiency.

particulates (PM) from Utah generators impacts air quality in Utah and downwind regions. These air quality impacts are, in turn, used to estimate the number of premature deaths, hospitalizations, and lost work days. Different EE and RE scenarios produce a range of emissions from fossil units in Utah, resulting in varying levels of health impacts. Ascribing a dollar value to life, health, and wellbeing is difficult and controversial, but is a required component of monetizing externalities and co-benefits. Our externality cost for each scenario in 2020 is derived from standard (federal) monetary values associated with statistical mortality and morbidity. This analysis is described in Chapter 4.

We estimate water consumption from historical records of cooling water requirements for fossil generating units in Utah. Assuming that no dramatic changes are made to the way cooling water is used at fossil generators, we can estimate future water consumption requirements based on generation. We estimate twp monetary externality prices for fresh water consumed based on, at the high end, the marginal “willingness to pay” for water rights in Utah and at the low end, the median water transaction price in Utah. The monetary cost of water used by power generation (including water intensive renewable energy projects) is the estimated social externality cost in Utah. Chapter 5 details these methodologies.

The baseline, energy efficiency, renewable energy, and replacement scenarios are all built from hourly load profiles, based on the model described in Chapter 3. To estimate the impact of these resources on hourly generation and emissions, we build load profiles from existing data sources detailing efficiency targets, wind availability, and solar patterns. The methods used to build the scenarios and their resulting externalities and co-benefits are described in Chapter 6.

The externalities estimated from this exercise are significant; we find that society is paying roughly as much for damages imparted by fossil generation in Utah as are ratepayers, on a unit-energy basis. However, despite these high costs, the co-benefit value of Utah-based EE and RE is relatively modest, unless a proactive approach to reducing damages is taken in concert with new resources. Chapter 7 presents key findings and discusses assumptions and policy implications.

This report is scoped with addressing secondary benefits and co-benefits of new EE and RE as well, particularly potential impacts on natural gas prices in Utah and possible reductions of regional haze. We postulate that there would be a negligible and fleeting (or non-existent) impact on natural gas prices form changes in generation in Utah, and find that there is insufficient data on haze constituents in Utah to characterize feasible reductions. We discuss these ancillary environmental and economic costs in accompanying appendices.

3. Avoided Generation and Emissions

In this research, we estimate the externalities avoided by implementing modest levels of new energy efficiency (EE) and renewable energy (RE) in Utah. This analysis seeks to quantify co-benefits from *marginal* changes in EE and RE, rather than systemic operational or structural changes to the electricity grid or market. The following chapter describes a method for estimating displaced or avoided generation and emissions, given an electrical grid largely similar to the one in operation today. An equally valid, but distinctly different approach might estimate displaced or avoided generation and emissions given a structurally different electricity market, such as one with a very high penetration of renewable energy, carbon constraints, or a modified transmission grid. The purpose of this study is to provide an estimate of the co-benefits of EE and RE in the near future.

To estimate marginal avoided generation and emissions, we construct a model simulating fossil dispatch dynamics based on historical generator behavior. One significant factor in this analysis is Utah's position as a net exporter of fossil generation for most months of the year. In this chapter, we (a) review the structure of the electricity sector in Utah and the US West, (b) describe our statistical dispatch model, and (c) review how the model is modified to incorporate seasonal changes imposed by hydroelectric output in the Northwest. The statistical dispatch model relies on limited, public historic generation data to estimate how fossil resources will respond to efficiency and renewable energy.

3.1. Electricity Generation and Demand in Utah and the West

Utah is a net exporter of electric power to the US West, generating over 45,372 GWh of energy in 2007, yet consuming only about 61% of the energy produced in the state (see Figure 3-1). Over 98% of Utah's generation in 2007 was derived from fossil resources (coal, petroleum, and gas), and of this, coal accounted for about 83% of all energy produced. Many of Utah's coal generators sit relatively close to coal mines; between rich local resources and inexpensive transportation costs, coal generation in Utah is a relatively inexpensive proposition. The amount of gas generation used in Utah has risen sharply since 2005, as several new combined cycle plants were brought into operation.

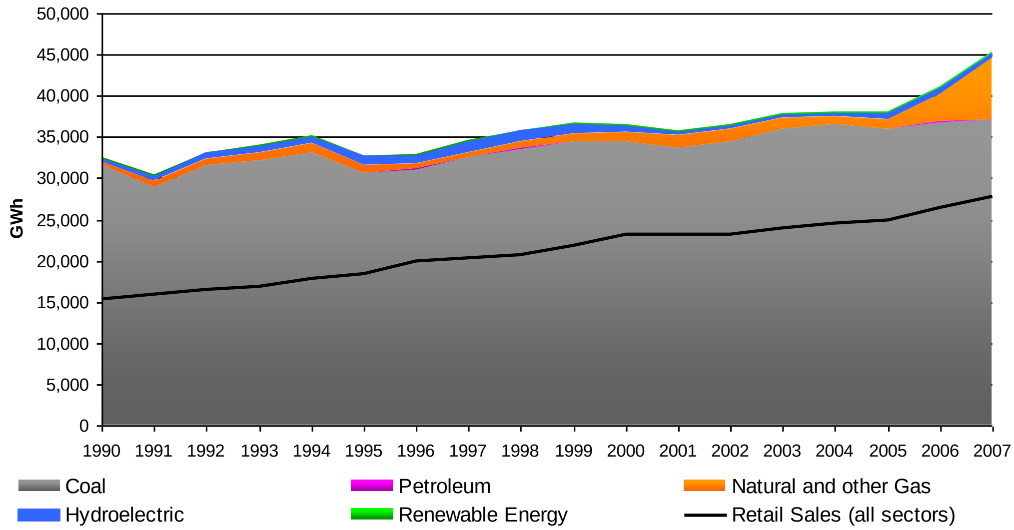


Figure 3-1: Electricity generation and consumption in Utah, 1990 through 2007. Fuel types labeled by color; the dark line represents demand in Utah over the same time period, on the same scale. Source: EIA[21,22]

Utah is part of a highly interconnected grid in the west, comprised of high capacity transmission running from the Rocky Mountain West (MT, WY, UT, and CO) to the Northwest (WA, OR and ID), and from the Southwest (NV, AZ, and NM) into California. There is significant transfer capacity from the Northwest down to California as well, and a direct connection between a coal power station in Utah (the Intermountain Power Project, or IPP) and southern California. Of the major sources of electricity throughout the West, coal generation in Utah, Wyoming, and Montana are amongst the least expensive (at least in terms of direct costs of generation).

The relationship between generation in the Rocky Mountain West (RMW) and electricity use in the Northwest and California is complex and important to this analysis, both in estimating power plant dynamics and in understanding the magnitude of co-benefits that can be expected from modest renewable or energy efficiency programs in Utah. In 2008, RMW and the Southwest produced ~230% and ~140% more energy, respectively than these regions required. In the same year, California imported ~20% of its electricity from other states in the West (see Figure 3-2), while the Northwest remained approximately energy balanced, on net.[23]

[21] US DOE Energy Information Administration, 2009. Utah Electricity Profile: Generation by Primary Energy Source, 1990 Through 2007. Available online at: http://www.eia.doe.gov/cneaf/electricity/st_profiles/sept05ut.xls

[22] US DOE Energy Information Administration, 2009. Utah Electricity Profile: Retail Sales, Revenue, and Average Retail Price by Sector, 1990 Through 2007. Available online at: http://www.eia.doe.gov/cneaf/electricity/st_profiles/sept08ut.xls

[23] Author's calculations. Source data EIA Form 861 (Demand) and EIA Form 923 (Generation), 2008.

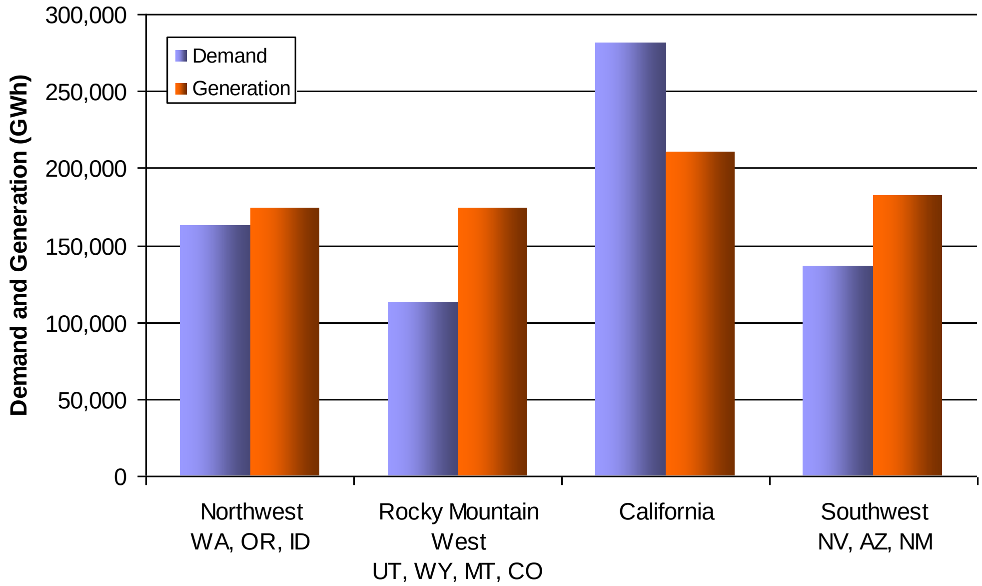


Figure 3-2: Electrical demand and gross generation in Western states, 2008. Source: EIA Forms 923 and 861.

Much of the electricity in the Northwest is produced from hydroelectric sources (70% in 2008), many of which are seasonally dependent on spring runoff, continuing through the summer. When hydroelectric energy is abundant, the Northwest supplies energy to California, and capacity to some parts of the RMW. When rivers run low in the autumn and winter, the Northwest imports significantly more energy from the RMW and supplies much less to California.[24] Therefore, generation in the RMW is highly dependent on hydroelectric conditions in the Northwest. The net effect is that the RMW region is able to supply relatively inexpensive coal generation to the Northwest, which in turn can "bank" the energy as water and supply premium hydroelectric energy to California during periods of high energy demand.

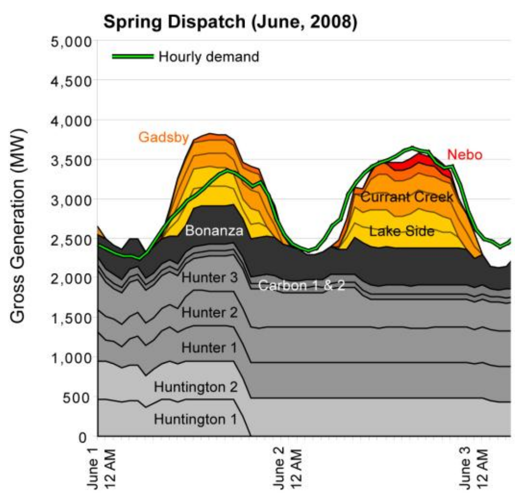
Utah is a net exporter to the Western grid, both via a direct current (DC) line from the coal-fired Intermountain Power Project (IPP) to southern California, and through connections to Idaho and the Northwest. IPP operates largely independently of demand in Utah: more than 80% of generation from the power station is sold and transferred directly to California. Other coal-fired stations operate nearly continuously, providing power to Utah during spring runoff (which coincides with peak demand in Utah), and energy for export during the autumn and winter (see Box 1, below). Gas fired power stations in Utah, however, respond both to daily fluctuations in demand, as well as seasonal changes in demand and interstate supply.

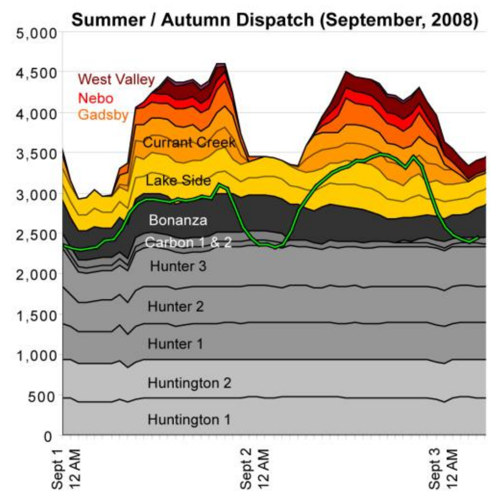
[24] Western Electric Coordinating Council. Historical Analysis Work Group. (April, 2009) *2008 Annual Report of the Western Electricity Coordinating Council'sTransmission Expansion Planning Policy Committee: Part 3 Western Interconnection Transmission Path Utilization Study.*

Box 1: Electric Generation Dispatch in Utah

Electric systems are typically dispatched in "economic merit" order to optimize resource use and provide electricity at the lowest possible direct cost. In economic dispatch, generators with the lowest operating and fuel costs operate often, while generators with higher costs operate less frequently. Electric dispatch can be visualized as a "stack" of generators, with the most often operating generators (baseload) at the bottom and least frequent (peakers) at the top. The diagrams below shows such stacks for Utah's fossil generators (excluding the Intermountain Power Project [IPP]) in spring (June) and summer (September), respectively. Coal generators appear in shades of gray, and gas generators appear in shades of orange. The total height of all of the stacked plots indicates the total gross generation of fossil generators in the state during any given hour. The green line indicates load requirements in Utah during these time periods.

The diagrams show that Utah is a net exporter of electric power during almost all times of the year. During spring runoff (left diagram), hydroelectric power is available in the Northwest, and Utah power plants are dispatched to primarily meet load requirements in Utah. In the autumn, hydroelectric power in the Northwest decreases, and fossil-fired generation increases. Utah generators run near maximum capacity, in this case delivering to out of state customers over 1,500 MW during peak hours and 1,000 MW during off-peak hours.





The primary difference between the spring and summer dispatch order is that both combustion and combined-cycle gas generators run at far higher capacity factors when hydroelectric energy is unavailable; some coal generators may undergo maintenance during these periods. Otherwise, coal generators in Utah run at very high capacity factors (>85%) in almost all circumstances.

Due to the complex regional interactions, and because Utah is a net exporter of generation, it is likely that demand reduction programs (EE or RE) will reduce more expensive gas generation in Utah, or provide the opportunity for Utah to export unused capacity to out-of-state markets. Coal generation in Utah is imperceptibly impacted by changes in demand in Utah today, and thus we can predict that it is unlikely that coal-fired generation will be displaced on the margin in Utah with moderate in-state EE or RE.

It is feasible, however, that more significant penetrations of RE, or regional moves to reduce energy consumption could impact coal-fired generators. Such regional transformations are not modeled in this analysis. Ultimately, as this analysis will show, as in other studies,[25,26] that the most significant health and water externalities from electrical generation are associated with coal generation. Therefore, we expect relatively small co-benefits from EE and RE unless coal generation is replaced by other energy sources.

To quantify the extent to which EE and RE in Utah could provide monetary co-benefits, we construct a dispatch dynamics model. The following section describes the model basis.

3.2. Displaced Emissions

In this paper, we define "displaced" emissions as those emissions that would otherwise be emitted from generators within our defined system in the absence of new energy projects. The question at hand can be defined simply: assuming that new EE reduces demand and new RE are must-take resources, which generators back down to balance load and generation? In a highly integrated electrical grid, the answer is not obvious.

A number of methods have been used to estimate emissions displaced on the margin when renewable energy or energy efficiency are brought online.[27] The question of how to calculate displaced emissions is, at its core, an economic question. In the absence of transmission or environmental constraints, resources are dispatched in economic merit order (see Box 1). In this research, rather than defining the costs and operational constraints of each resource to approximate the loading order, we use historical behavior to statistically represent each unit's behavior relative to demand, a behavior which, we assume, has been guided by economics, as well as operational and transmission constraints.

The basis of this model is that, within a conceptual box, generation is dispatched to meet load requirements. When load increases, generation must increase somewhere in the system to meet the load requirement; conversely, when load decreases, some electricity generation units will decrease generation accordingly. The model examines historical behavior in load and generation and predicts how each generator will respond if load increases or decreases. Therefore, as load increases or decreases, the model will estimate the amount of generation that would have historically been required to meet the load requirement, and the quantity of pollutants that would have been emitted if the generator had operated as predicted. In this model framework, adding small to moderate

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[25] National Research Council of the National Academy of Sciences. 2009. Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use. National Academies Press.
[26] Lockwood, A.H., K. Welker-Hood, M. Rauch, B. Gottlieb. November, 2009. Coal's Assault on Human Health. Physicians for Social Responsibility.
[27] Several other approaches are described in Appendix C: Displaced Emissions, Background.

amounts of renewable energy or energy efficiency to the system is similar to decreasing hourly load requirements. As existing fossil generators see lower loads, they decrease generation (and emissions) and are thus displaced.

Synapse Energy Economics developed the following analytical technique for the State of Connecticut and the US Environmental Protection Agency to estimate emissions reductions from energy efficiency and scrubber technologies.[28] The model estimates generation and subsequent emissions from the relationship between historic hourly load (demand) and fossil generation. In the model, statistics are defined for the frequency of unit operation (on or off) and unit generation (MW output) for any given demand, and the probability distribution of emissions of NO_x, SO_2, and CO_2 for unit generation. Once these statistics are defined, a Monte Carlo simulation is used to estimate expected mean and distribution of generation and emissions at each load level.

Our model construct is backwards looking, building a statistical database that portrays the system behavior at a period of time. Manipulating some of the assumptions of this statistical model, we can predict how simple, short-term changes will impact dispatch operations.

3.3. Data sources: Demand, Generation, and Emissions

The model requires inputs of hourly load for an appropriate time-period (in this case, a full leap year, or 8,784 hours) and hourly fossil generation from units which comprise some defined region of the grid (preferentially a full power control area). The model structure developed here is unique in that it estimates generation dynamics from historical and generally non-proprietary data. The detailed hourly generation and emissions data are freely available from the EPA. Hourly demand was obtained from utility sources.

3.3.1. Hourly Load Data

The reference year for the Utah analysis begins in the fourth quarter of 2007 (October 1, 2007) and runs through the end of the third quarter in 2008 (September 30, 2008). At the time of this analysis, complete year 2008 data were unavailable for either load or generation. In addition, the Lake Side combined cycle plant was brought online in 2007, and was not fully operational until the third quarter of the year. Because the use of either calendar year would result in an incomplete dataset, the reference year comprises parts of both.

PacifiCorp provided hourly load profiles for 2007 and 2008 in each service region, including Utah. Over the time period of interest, PacifiCorp provided over 80% of

[28] James, C., J. Fisher. June 10, 2008. Reducing Emissions in Connecticut on High Electric Demand Days (HEDD): A report for the CT Department of Enviromental Protection and the US Environmental Protection Agency. Available online at http://www.ct.gov/dep/lib/dep/air/energy/ct_hedd_report_06-12-08_12noon.pdf

electricity in Utah (see Table 3-1).[29] Hourly load data were unavailable from other electricity providers in Utah; therefore contemporary PacifiCorp loads were scaled up to represent total monthly demand in Utah.[30] It is assumed that the historical and future hourly load profiles of other load-serving entities in Utah are proportional to that of PacifiCorp.

Table 3-1: Largest 10 load-serving entities in Utah in 2007. *Source: EIA Form 861*

Electric Utility	Sales (MWh)	Fraction of State Sales
PacifiCorp (Utah)	22,352,159	80.4%
Provo City Corporation	793,540	2.9%
City of St. George	620,654	2.2%
City of Logan	429,124	1.5%
City of Murray	371,964	1.3%
Moon Lake Electric Assn. Inc.	367,492	1.3%
Dixie Escalante R E A, Inc.	320,820	1.2%
City of Bountiful	307,068	1.1%
City of Springville	237,306	0.9%
Spanish Fork City Corporation	203,050	0.7%

3.3.2. Hourly Fossil Generation and Emissions Data

Generation and emissions are derived from the EPA Clean Air Markets Division (CAMD) dataset of hourly reported gross generation, heat input, and emissions of NO_x, SO_2, and CO_2.[31] The data are collected by the EPA Continuous Emissions Monitoring (CEM) program to inform compliance with the Acid Rain Program, Title IV of the Clean Air Act.[32] The program covers all fossil power units over 25 MW. The CAMD dataset is made available to the public and updated on a quarterly basis.

Table 3-2 shows statistics for the units in this analysis, including the unique DOE code for each plant (ORISPL), the first year the generator was in operation, the operating capacity of the plant during the study period (in MW), the total gross generation over the study period, hours in operation (out of a total of 8,784),[33] capacity factor, and average emissions rates over the study period.

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[29] US Department of Energy, Energy Information Administration (2009). Form 826, Monthly Electric Utility Sales and Revenue Data. Available online at http://www.eia.doe.gov/cneaf/electricity/page/eia826.html

[30] Monthly demand by major utilities, cooperatives, and municipal utilities in Utah from EIA Form 826

[31] Available at http://camddataandmaps.epa.gov/gdm/

[32] US EPA (2009). Acid Rain Program: Emissions Monitoring and Reporting. http://www.epa.gov/airmarkets/progsregs/arp/basic.html

[33] Year 2008 included a leap year, increasing total hours in the analysis period by 24 hours to 8,784.

Table 3-2: Basic information on fossil units in Utah that report to the CAMD database.

Plant Name	Unit ID	Fuel Type	ORISPL [a]	Generator Year Online [b]	Gross Operating Capacity (MW)[c]	Gross Generation (MWh)	Hours in Operation [d]	Capacity Factor	Emissions Rate NO_x lbs/MWh	Emissions Rate SO_2 lbs/MWh	Emissions Rate CO_2 tons/MWh
Bonanza	1-1	Coal	7790	1986	507	3,965,905	8,607	89.1%	3.60	0.52	1.07
Carbon	1	Coal	3644	1954	79	560,449	8,171	80.8%	5.29	8.06	1.03
Carbon	2	Coal	3644	1957	113	753,150	7,190	75.9%	5.16	8.58	1.11
Currant Creek	CTG1A	Gas	56102	2005	289	1,607,484	7,660	63.3%	0.06	0.00	0.39
Currant Creek	CTG1B	Gas	56102	2005	295	1,609,129	7,645	62.1%	0.06	0.00	0.38
Gadsby	1	Gas	3648	1951	60	48,037	1,664	9.1%	1.44	-	0.79
Gadsby	2	Gas	3648	1952	72	71,451	2,091	11.3%	1.44	0.00	0.80
Gadsby	3	Gas	3648	1955	107	135,590	2,635	14.4%	0.85	0.00	0.67
Gadsby	4	Gas	3648	2002	42	93,016	4,209	25.2%	0.18	-	0.63
Gadsby	5	Gas	3648	2002	42	90,939	4,075	24.6%	0.17	-	0.61
Gadsby	6	Gas	3648	2002	44	88,264	3,980	22.8%	0.17	-	0.61
Hunter	1	Coal	6165	1978	464	3,487,376	8,201	85.6%	3.92	1.59	1.07
Hunter	2	Coal	6165	1980	465	3,631,600	8,602	88.9%	3.85	1.32	1.04
Hunter	3	Coal	6165	1983	506	3,869,964	8,439	87.1%	3.44	0.56	0.96
Huntington	1	Coal	8069	1977	485	3,611,204	8,192	84.8%	3.34	1.33	0.94
Huntington	2	Coal	8069	1974	491	3,942,857	8,574	91.4%	2.10	0.52	0.98
Nebo	U1	Gas	56177	2004	151	572,325	4,928	43.1%	0.17	0.00	0.44
West Valley	U1	Gas	55622	2002	60	107,093	4,186	20.3%	0.21	-	0.61
West Valley	U2	Gas	55622	2002	60	108,051	4,261	20.5%	0.18	-	0.61
West Valley	U3	Gas	55622	2002	60	89,225	3,754	16.9%	0.17	-	0.62
West Valley	U4	Gas	55622	2002	40	97,684	3,899	27.8%	0.19	-	0.61
West Valley	U5	Gas	55622	2002	41	96,163	3,726	26.7%	0.15	-	0.60
Lake Side	CT01	Gas	56237	2007	307	1,636,421	7,072	60.7%	0.04	0.00	0.38
Lake Side	CT02	Gas	56237	2007	308	1,691,057	7,235	62.5%	0.04	0.00	0.38
Millcreek	MC-1	Gas	56253	2006	40	35,067	928	10.0%	0.56	-	0.52
Intermountain	1SGA	Coal	6481	1986	956	7,785,281	8,376	92.7%	3.72	0.76	0.96
Intermountain	2SGA	Coal	6481	1987	965	7,365,781	7,912	86.9%	3.54	0.74	0.97

[a] ORISPL = DOE plant identification number. Multiple units comprise single plants; combined cycle units are identified by combustion turbine components.
[b] Generator year online from EPA eGRID dataset
[c] Capacity in this table represents maximum gross generation (before busbar) reported during study period, as reported to CAMD. This value may differ from reported nameplate net capacity.
[d] Hours online represents the number of hours during the study period where gross generation is greater than zero. Study year has 8784 hours.

3.4. Representation of exports and seasonal dynamics

The analysis estimates total required generation on an hourly basis by comparing trends of historic gross generation and demand. In most regions of the country, these are correlated, but not necessarily the same, depending on imports and exports. The basis of the analysis relies on an implicit relationship between total system load and individual unit operations.

Due to the significant differences between demand and generation during periods of high imports and exports, the analysis required a manual characterization of period of high export or moderate imports due to hydroelectric operations in the Northwest.

Figure 3-3 shows the relationship between Utah hourly demand during the study period and Utah hourly fossil generation over the same period, plotting 8,784 data points of demand and generation on a scatterplot.[34] If every unit of generation produced in Utah was consumed in Utah, this graph would show only a 1:1 line, with as much being consumed as being produced. Instead, this figure shows that demand in Utah is not strongly correlated with generation in Utah. Often, generation exceeds demand by as much as 2000 MW, and is sometimes lower than demand by a few hundred MW.

During periods of either high hydroelectric availability in the Northwest or high local demand, Utah's generators ramp with local load requirements (the lower, nearly 1:1 bound on the scatter plot of load versus generation in Figure 3-3) and exports are small. However, during the autumn and early spring, when hydroelectric availability is low, baseload coal generators increase operations.

[34] The figure excludes generation from the Intermountain Power Project (IPP), 80% of which is sold to California through a high capacity direct current transmission line.

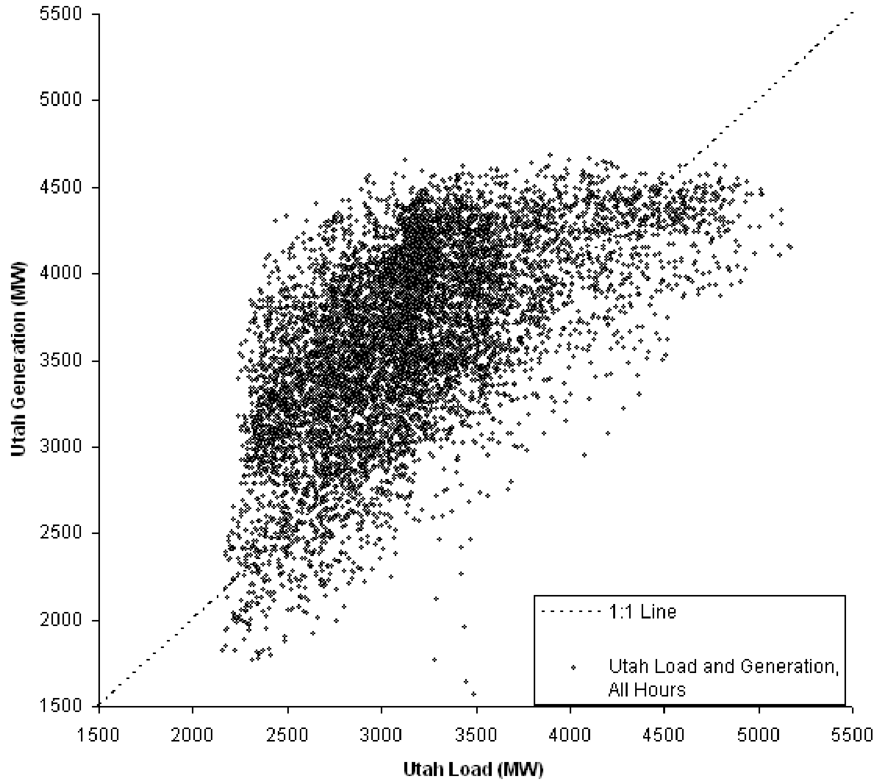

Figure 3-3: Hourly generation and load in Utah, excluding the IPP facility. Each point represents one hour during the study period (8784 points total). Points near the 1:1 line are periods of few net exports. Exports are above the 1:1 line; the top of the triangle is saturated generation, where all Utah generators are operating near full capacity.

Because of these significant discrepancies in behavior relative to an exogenous variable, hydroelectric capacity, we divide the year into two categories:

Category A: High hydroelectric availability in the northern Western Electric Coordination Council (WECC-N) Region *and/or* high demand in Utah (minimal exports from Utah)

Category B: Low hydroelectric availability (high level of exports from Utah)

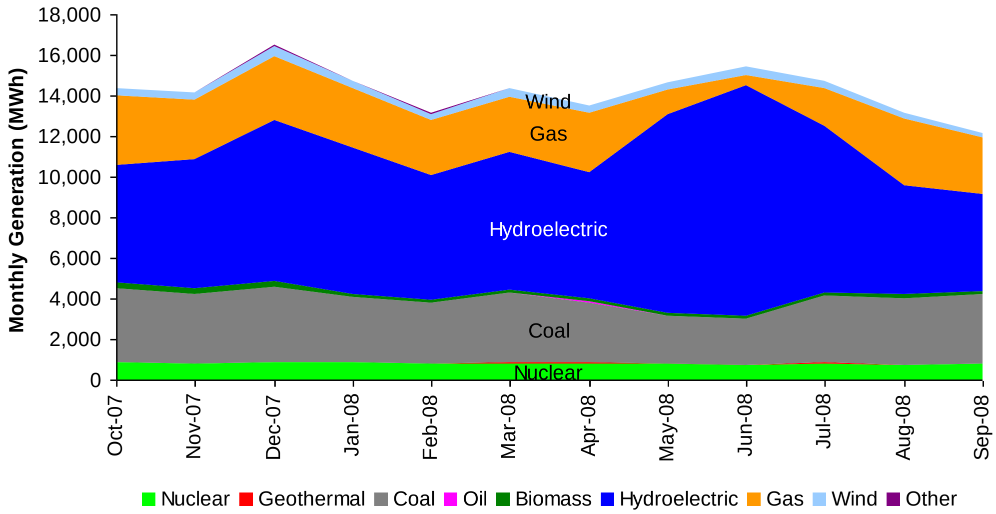

Figure 3-4: Monthly generation in the Western Electric Coordination Council (WECC-N) Region (includes OR, WA, ID, MT, UT, and parts of CA, WY, and CO). Hydroelectricity output peaks May through July, displacing gas and coal. A smaller peak occurs in the winter.

Examining patterns of load and generation throughout the region, and monthly hydroelectric generation in WECC (see Figure 3-4 and Figure 3-5), we chose the period from May 4th through August 31st and November 28th through March 3rd (with the exception of December 18 to January 1st) in Period A, and the remainder of the year in Period B. These categorizations roughly separate the year into periods when plants in Utah are exporting, and when Utah load is served by local generation (see Box 1, page 21).

A timeline of average daily load and generation (excluding the Intermountain Power Plant) during the study period is shown in Figure 3-5. On top of the time series, shaded regions indicate the dates covered by load periods A and B. Dispatch dynamics are fundamentally different during these two load periods (see Box 1, above), and so we analyze fossil displacement within each period independently.

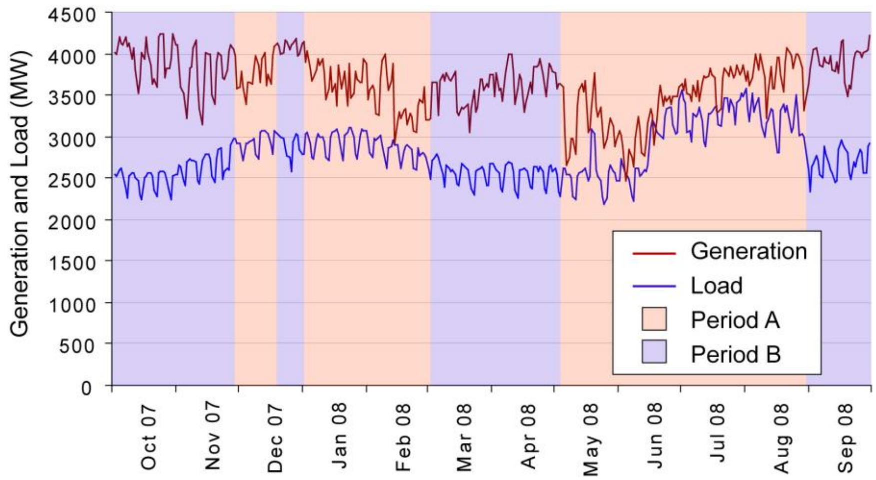

Figure 3-5: Time series of average daily generation (red) and load (blue) in Utah. Shaded regions represent load periods, differing by level of demand and hydroelectric operations.

3.4.1. Generation Statistics from Load

Statistics are gathered from the generation dataset by examining discrete "load bins", the hours when load fell between an upper and lower bounding demand. There are 40 such load bins, distributed such that each load bin represents the same number of hours. These bins can be envisioned as evenly spaced slices of a load duration curve. In this study, there are 8784 hours divided into two "categories" due to fluctuating hydroelectric conditions in the Northwest (see section above); bins in the first period (A) represent 123 hours each, and bins in the second period (B) represent 101 hours each.

In each load bin, two statistics are gathered:

- The probability that each unit is operational, defined by the number of hours in which a unit generates more than zero gross MW, divided by the number of hours in the bin.
- The probability distribution function of the unit's generation within the load bin, in linearly spaced categories.

Operational Probability

The fraction of time that an electricity generating unit (EGU) is operational is a function of the type of generator, relative to the generation mix. For example, a baseload unit, or a unit which is maintained for the purposes of exporting energy, will be operational even when very little load is demanded (off-peak hours), and thus generate in most of the load bins. A peaking unit, however, is unlikely to ever operate at low load levels, but might occasionally operate at high loads. For forecasting purposes, this analysis assumes that the historical fraction of time that a unit operated at any given load is also the probability that it will operate in the future at that same load, given similar conditions.

The analysis algorithm references each hour of the year into a load bin. In each load bin (i.e. each "slice" of the load duration curve), we count the number of hours in which each generator was operational. The operational probability for each generator in each load bin is simply the number of hours the unit was operational divided by the total hours in the bin.

Generation Probability Distribution

When units do run, the amount generated is often also a function of demand. The program collects statistics for each generator on how much energy the unit produces in each load bin. The information is translated into a discrete probability distribution function with twenty different generation options. This process creates a histogram of potential power outputs for a generator when a particular load is demanded.

The analysis algorithm parses each EGU's generation into twenty bins, from one MW output to the maximum output of the EGU. Within each load bin, for each hour that the generator is operational, the level of its output is used to score one of the twenty load bins. For example, combustion turbine #1 on the Currant Creek Power Project is able to generate up to 270 MW, so twenty bins of approximately 13.5 MW each are created in each load bin. In almost all hours where Utah load is above 3,500 MW, the unit has a gross generation of 210 MW. When Utah load drops below 3,500 MW, the unit reduces generation to about 160 MW. This behavior is captured in the statistics represented by the generation probability distribution. The distribution is used to then estimate future output under new load conditions.

3.4.2. Emissions statistics from generation (probabilistic emissions rate)

Unit emissions statistics relative to unit generation are gathered from the database similarly to the way in which generation statistics were gathered relative to load. For many types of units, emissions are a reasonably straightforward function of generation (higher emissions when more power is generated). In other datasets,[35] emissions are calculated as a rate relative to generation (lbs NO_x / MWh, or tons CO_2 / MWh), assuming a linear increase with generation. However, emissions (particularly NO_x and SO_x) are not always tightly correlated with generation (see Figure 3-6), and can vary depending on running conditions, operating temperatures, and whether emissions controls are in operation.

[35] For example, see the US Environmental Protection Agency's eGRID dataset (http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html), one of the most comprehensive resources for plant-level, state and regional emissions reporting data, based on the CAMD dataset.

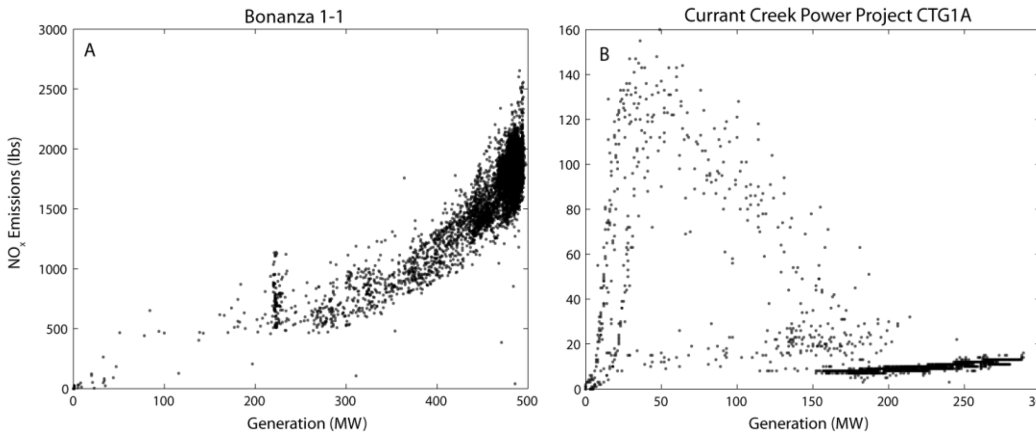

Figure 3-6: NOx emissions versus generation for two Utah EGUs. Dots represent hours of the year; there are 8784 dots per scatter plot. (A) Emissions from Bonanza 1-1 rise with generation output along a non-linear curve. (B) Currant Creek 1 emissions are high as the plant warms from cold start; emissions rise slowly past 150 MW of output. *Please note that the graph scales are different and not proportional.*

The model uses 20 generation bins, or categories, for each unit, bounded by zero and the highest recorded generation output the unit. Emissions are recorded in all hours where the unit generated the amount in each bin. Within each generation bin, a probability distribution function (PDF) of emissions is created. For some units, this is a very tightly bounded constraint (where emissions are fixed for a particular level of generation), while for other units, this distribution can be quite wide.

3.4.3. Monte Carlo Simulation

We use a Monte Carlo simulation to estimate generation and emissions under certain load conditions. A Monte Carlo simulation is a method of obtaining both likely average system behavior and error bounds when there are a large number of uncertain variables. This analytical technique runs a model numerous times (in this case, one hundred), each time drawing the value for uncertain variables randomly according to a probability distribution function. The median result of all of the runs is the expected value, and the variance of the results defines the error term. In this analysis, there is uncertainty on:

1. the number of units operating when a particular demand is required,
2. the generation level of those units which are operating when a particular demand is required, and
3. the emissions level of those units at a particular generation.

The analysis solves for expected generation and load by running 100 manifestations of the model in the Monte Carlo simulation. This process is divided into three distinct steps:

1. choosing which units operate,
2. choosing the generation of each of these units, and
3. choosing the emissions level of each of these units.

Each manifestation of the Monte Carlo approach runs as follows. The model determines the correct load bin for a given hourly load. Within this load bin, each plant has a certain probability of operating. A random variable is used to determine if a unit will operate or not, given its probability. For each unit determined to be in operation, a second random variable determines the level of operation, based on the probability distribution function of generation.[36] Finally, given the level of operation (in MW), a final random variable determines the emissions in that hour, given the probability distribution function of emissions. Results are reported as total annual generation and annual emissions of NO_X, SO_2, and CO_2 for all iterations of the Monte Carlo run. In post processing, the median is obtained from the series of runs. The results are used to estimate mortality and morbidity from air emissions, and water use from generation, as described in the next two chapters.

[36] This is accomplished by transforming the PDF into a cumulative distribution function (CDF), with values from zero to one. When the random variable is drawn, it is compared to the CDF and chooses the generation with a cumulative probability less than or equal to the random variable. If we repeat this operation multiple times, the histogram of all chosen generation values converges on the shape of the PDF.

4. Emissions and Health

4.1. Introduction

The public health implications of emissions from power plants are generally estimated using a damage function approach, in which emissions of key pollutants are estimated, population exposures resulting from those emissions are modeled, and the health impacts of those exposure changes are quantified given epidemiological evidence for a variety of health outcomes. In many circumstances, it is also desirable to assign monetary values to health outcomes, reflecting either direct health care costs or societal willingness to pay to avoid adverse health effects. These values allow for a comparison with control costs as well as a mechanism to aggregate across disparate health outcomes. This methodology has been widely applied, including by the EPA when estimating the public health benefits of air pollution regulations,[37,38,39,40] and within the academic literature.[41,42,43,44,45] The approach has also been endorsed by the EPA Science Advisory Board [46], the U.S. Office of Management and Budget [47], and the National Academy of Sciences [48], among others.

Generally, fairly complex chemistry-transport models are used to simulate the effects of emission changes on ambient concentrations across a large geographic area. However, such models are computationally and resource intensive and are impractical for applications such as this. To allow the results from previous detailed modeling

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37 US Environmental Protection Agency, *The Benefits and Costs of the Clean Air Act: 1990 to 2010*. Office of Air and Radiation: Washington, DC, 1999.

38 US Environmental Protection Agency, *Regulatory Impact Analysis - Control of Air Pollution from New Motor Vehicles: Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements*. Office of Air and Radiation: Washington, DC, 1999.

39 US Environmental Protection Agency *Final Regulatory Analysis: Control of Emissions from Nonroad Diesel Engines*; EPA420-R-04-007; Assessment and Standards Division, Office of Transportation and Air Quality: Washington, DC, 2004.

40 US Environmental Protection Agency *Regulatory Impact Analysis for the Final Clean Air Interstate Rule*; EPA-452/R-05-002; Office of Air and Radiation: Washington, DC, 2005.

41 Levy, J. I.; Greco, S. L.; Spengler, J. D., The importance of population susceptibility for air pollution risk assessment: A case study of power plants near Washington, DC. *Environmental Health Perspectives* **2002,** 110, 1253-1260.

42 Levy, J. I.; Hammitt, J. K.; Yanagisawa, Y.; Spengler, J. D., Development of a new damage function model for power plants: Methodology and applications. *Environmental Science & Technology* **1999,** 33, 4364-4372.

43 Levy, J. I.; Spengler, J. D., Modeling the benefits of power plant emission controls in Massachusetts. *J Air Waste Manage Assoc* **2002,** 52, 5-18.

44 Muller, N. Z.; Mendelsohn, R., Measuring the damages of air pollution in the United States. *Journal of Environmental Economics and Management* **2007,** 54, (1), 1-14.

45 Lopez, M. T.; Zuk, M.; Garibay, V.; Tzintzun, G.; Iniestra, R.; Fernandez, A., Health impacts from power plant emissions in Mexico. *Atmospheric Environment* **2005,** 39, (7), 1199-1209.

46 US Environmental Protection Agency, *Air Quality Criteria for Particulate Matter*. Office of Research and Development: Research Triangle Park, NC, 2004.

47 US Environmental Protection Agency, *Regulatory Impact Analyses for the Particulate Matter and Ozone National Ambient Air Quality Standards and Proposed Regional Haze Rule*. Office of Air Quality Planning and Standards: Research Triangle Park, NC, 1997.

48 Committee on Estimating the Health-Risk-Reduction Benefits of Proposed Air Pollution Regulations, *Estimating the Public Health Benefits of Proposed Air Pollution Regulations.* National Research Council: Washington, DC, 2002

applications to be extrapolated to unstudied sources and settings, researchers have developed a concept known as the intake fraction.[49] This simply reflects the fraction of an emitted pollutant or its precursor that is inhaled by some member of the population. For primary pollutants,[50] the emitted pollutant is identical to the exposed pollutant, and the intake fraction represents atmospheric dispersion, deposition, and population density downwind of the source. For secondary pollutants (such as ozone, sulfate, or nitrate), the intake fraction characterizes the concentrations associated with emissions of the precursors (such as NO_x or SO_2), and represents the above elements for primary pollutants as well as chemical transformation in the atmosphere. Intake fractions will clearly vary by source and location, so it is necessary to either apply estimates from closely analogous sources or from regression models that explain variability in intake fractions as a function of available covariates.[51,52] Other researchers have used complex chemistry-transport models to develop relatively simple source-receptor models that can allow for rapid assessments of the impact of changes in emissions at a given source on concentrations at a number of receptor locations. [38,53,54]

Given an exposure model, the applicability of the damage function approach ultimately hinges on the assumption that the modeled pollutants have public health impacts at current and projected future ambient concentrations (i.e., that background concentrations are above any potential population threshold). Two air pollutants for which this assumption appears to hold at present are fine particulate matter ($PM_{2.5}$) and ozone. $PM_{2.5}$ has been associated with a number of health outcomes, including mortality from long-term exposure,[55,56,57,58] mortality from short-term exposure,[59,60,61] and various

[49] Bennett, D. H.; McKone, T. E.; Evans, J. S.; Nazaroff, W. W.; Margni, M. D.; Jolliet, O.; Smith, K. R., Defining intake fraction. *Environ Sci Technol* **2002,** 36, (9), 207A-211A.

[50] Primary pollutants include: carbon monoxide (CO), oxides of nitrogen (NO_X), sulfur dioxide (SO_2), volatile organic compounds (VOCs), and particulates ($PM_{2.5}$).

[51] Levy, J. I.; Wolff, S. K.; Evans, J. S., A regression-based approach for estimating primary and secondary particulate matter intake fractions. *Risk Analysis* **2002,** 22, 895-904.

[52] Zhou, Y.; Levy, J. I.; Evans, J. S.; Hammitt, J. K., The influence of geographic location on population exposure to emissions from power plants throughout China. *Environ Int* **2006,** 32, (3), 365-73.

[53] Tong, D. Q.; Mauzerall, D. L., Summertime state-level source-receptor relationships between nitrogen oxides emissions and surface ozone concentrations over the continental United States. *Environ Sci Technol* 2008**,** 42, (21), 7976-84.

[54] Abt Associates *User's Manual for the National Co-Benefits Risk Assessment Model, Beta Version 2.0.*; US EPA State and Local Capacity Building Branch: Bethesda, MD, 2004.

[55] Dockery, D. W.; Pope, C. A.; Xu, X.; Spengler, J. D.; Ware, J. H.; Fay, M. E.; Ferris, B. G. J.; Speizer, F. E., An association between air pollution and mortality in six U.S. cities. *New England Journal of Medicine* **1993,** 329, (24), 1753-1759.

[56] Laden, F.; Schwartz, J.; Speizer, F. E.; Dockery, D. W., Reduction in fine particulate air pollution and mortality: Extended follow-up of the Harvard Six Cities study. *Am J Respir Crit Care Med* **2006,** 173, (6), 667-72.

[57] Pope, C. A., 3rd; Thun, M. J.; Namboodiri, M. M.; Dockery, D. W.; Evans, J. S.; Speizer, F. E.; Heath, C. W., Jr., Particulate air pollution as a predictor of mortality in a prospective study of U.S. adults. *American Journal of Respiratory & Critical Care Medicine* **1995,** 151, (3 Pt 1), 669-74.

[58] Pope, C. A.; Burnett, R. T.; Thun, M. J.; Calle, E. E.; Krewski, D.; Ito, K.; Thurston, G. D., Lung cancer, cardiopulmonary mortality, and long-term exposure to fine particulate air pollution. *JAMA* **2002,** 287, (9), 1132-41.

[59] Daniels, M. J.; Dominici, F.; Samet, J. M.; Zeger, S. L., Estimating particulate matter-mortality dose-response curves and threshold levels: an analysis of daily time-series for the 20 largest US cities. *American Journal of Epidemiology* **2000,** 152, (5), 397-406.

non-fatal outcomes ranging in severity.[62, 63] Importantly, these studies have not shown a threshold below which health effects are not observed. A generally linear concentration-response function is present throughout the range of ambient concentrations. Similarly, ozone has been associated with mortality due to short-term exposure at current ambient concentrations,[64,65,66,67] and with various non-fatal outcomes. [68] Prior regulatory impact analyses demonstrate that the vast majority of the public health benefits of air pollution control strategies are due to reduced exposure to $PM_{2.5}$ and ozone.[37,38,39,40] Thus, we focus on these two pollutants in our analysis.

As a general point, while this damage function approach is well-supported in the academic and regulatory literature, it clearly contains some significant uncertainties, especially given limitations in available emissions data, uncertainties in chemistry-transport modeling, and the assumptions regarding health effects at current ambient concentrations and the economic values assigned to those health effects. Uncertainties are discussed at length later in this chapter, but it should be recognized that the values presented in this report are meant to be plausible central estimates, with the objective that it is equally likely that the impacts are above or below the reported values.

Below, we describe the methodology we apply to estimate the public health impacts associated with various emissions and generation scenarios in Utah. We first describe the source of emissions data utilized, which is directly available for SO_2 and NO_x but requires estimation for primary $PM_{2.5}$. We describe the methodology used to estimate population exposure, including both a subset of power plants where prior modeling efforts defined chemistry-transport outputs, as well as a subset for which exposures needed to be estimated indirectly using intake fraction concepts. We summarize the studies used to develop concentration-response functions for $PM_{2.5}$ and ozone, focusing herein on premature mortality and selected morbidity outcomes. We describe the methods used to characterize population patterns, baseline disease rates, and economic

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[60] Dominici, F.; Daniels, M.; McDermott, A.; Zeger, S. L.; Samet, J. M., Shape of the exposure-response relation and mortality displacement in the NMMAPS database. In *Health Efffects Institute Special Report: Revised Analyses of Time-Series Studies of Air Pollution and Health*, Charlestown, MA, 2003; pp 91-96.

[61] Schwartz, J. *Airborne particles and daily deaths in 10 US cities*; Health Effects Institute: Boston, MA, 2003, 2003; pp 211-218.

[62] Zanobetti, A.; Schwartz, J., The effect of particulate air pollution on emergency admissions for myocardial infarction: a multicity case-crossover analysis. *Environ Health Perspect* **2005,** 113, (8), 978-82.

[63] Bateson, T. F.; Schwartz, J., Who is sensitive to the effects of particulate air pollution on mortality? A case-crossover analysis of effect modifiers. *Epidemiology* **2004,** 15, (2), 143-9.

[64] Bell, M. L.; Peng, R. D.; Dominici, F., The exposure-response curve for ozone and risk of mortality and the adequacy of current ozone regulations. *Environ Health Perspect* **2006,** 114, (4), 532-6.

[65] Levy, J. I.; Chemerynski, S. M.; Sarnat, J. A., Ozone exposure and mortality: an empiric bayes metaregression analysis. *Epidemiology* **2005,** 16, (4), 458-68

[66] Ito, K.; De Leon, S. F.; Lippmann, M., Associations between ozone and daily mortality: analysis and meta-analysis. *Epidemiology* **2005,** 16, (4), 446-57.

[67] Bell, M. L.; Dominici, F.; Samet, J. M., A meta-analysis of time-series studies of ozone and mortality with comparison to the national morbidity, mortality, and air pollution study. *Epidemiology* **2005,** 16, (4), 436-45.

[68] Ostro, B. D.; Tran, H.; Levy, J. I., The health benefits of reduced tropospheric ozone in California. *J Air Waste Manag Assoc* **2006,** 56, (7), 1007-21.

values for premature mortality and morbidity, and we conclude by listing the key assumptions and uncertainties in our modeling framework.

4.2. Methodology

As a general point, we note that the methods below are described in extensive detail in two publications by this section's author, Dr. Jonathan Levy. Methods for estimating $PM_{2.5}$ externalities are described in Levy, Baxter and Schwartz (2009),[69] while concentration-response functions for ozone morbidity and mortality are detailed in Ostro, Tran and Levy (2006).[68] Below, we briefly summarize these methods and provide detail about aspects of our analysis not included in these publications, but refer the reader to the original publications for more methodological detail.

4.2.1. Emissions

For each of the scenarios developed, SO_2 emissions, NOx emissions, and MWh generated were simulated for each power plant for each simulated year (see Chapter 3). We used these emissions estimates directly for each power plant, focusing on the average estimates across Monte Carlo simulations, and considering 2007, 2010, 2015, and 2020 for health risk estimation. Primary $PM_{2.5}$ emissions were not simulated, so these emissions needed to be approximated external to the simulations. For many power plants, primary $PM_{2.5}$ emissions are estimated in the EPA National Emissions Inventory (NEI) database. The most recent data available at the time of our assessment was for 2002. We used that data combined with MWh generated for these plants to determine the emissions per MWh generated for each plant. Lacking any data to the contrary, we assumed that emissions would remain proportional to electricity generation in future years, and scaled emissions accordingly across all scenarios.

Primary $PM_{2.5}$ emissions data were not available from the NEI or the Utah DEQ for four power plants (Nebo, Currant Creek, Lake Side, and Millcreek). Primary $PM_{2.5}$ emissions therefore needed to be approximated for these plants. Lacking detailed data on plant configuration and combustion technology, we simply calculated the average primary $PM_{2.5}$ emission rate per MWh for gas-fueled power plants within this study (West Valley and Gadsby), and we applied this rate to all four power plants lacking any emissions data. This clearly represents a fairly significant uncertainty from the perspective of primary $PM_{2.5}$ emissions (especially given that some of the plants lacking data are combined-cycle plants, whereas the plants with data are thermal or gas turbines), and the implication of this assumption is considered within our analysis.

4.2.2. Exposure Characterization

Chemistry-transport modeling had been previously conducted for primary and secondary $PM_{2.5}$, using a source-receptor (S-R) matrix, for all of the coal-fired power plants in Utah considered within this study (Bonanza, Carbon, Hunter, Huntington, and Intermountain Power Project).[69] The results of this modeling could therefore be used directly, providing

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[69] Levy, J. I.; Baxter, L. K.; Schwartz, J., Uncertainty and variability in health-related damages from coal-fired power plants in the United States. *Risk Anal* **2009,** 29, (7), 1000-14.

estimates not only of total population exposure, but also of population exposure within Utah and within each county across the United States. Population exposure to $PM_{2.5}$ emissions are based on previous modeling exercises, which carry an intrinsic degree of uncertainty. In addition, the same S-R matrix used in this recent publication had sufficient data to directly model the exposures associated with emissions from Gadsby. For the remaining gas-fired power plants (Nebo, Currant Creek, Lake Side, Millcreek, and West Valley Generation Project), no such models were available, so we needed to utilize the intake fraction concept described above to approximate population exposures. We applied a regression equation derived in a prior publication and detailed in Levy, Baxter and Schwartz (2009), which characterized primary and secondary particulate matter intake fractions for a number of power plants across the United States as a function of population within various distances of the plants. Thus, greater uncertainty would be anticipated for the exposure and health impact estimates for these gas-fired power plants.

For ozone, directly-modeled estimates are not available for any of the individual power plants. Instead, we use a source-receptor matrix developed by Tong and Mauzerall [53] to estimate the intake fractions of ozone for every ton of NO_x emitted in Utah. Tong and Mauzerall analyzed the effect of interstate transport on surface ozone in each continental US state in July 1996 using the Community Multiscale Air Quality (CMAQ) model. The S-R matrices show the effect NO_x emissions from one state (source state) have on surface O_3 concentrations over the source state and other states (receptor states) for July 1996 mean daily peak 8-h as well as 24-hour O_3 concentration changes. Based on their model results, we derive the relationship between NO_x emissions from Utah in July 1996 (8-hr max) and the ozone mass inhaled by the population residing in the six states in which ozone impacts were found to be non-zero in their S-R matrix (Idaho, New Mexico, Arizona, Wyoming, Colorado, and Utah). Clearly, there are significant uncertainties associated with using state-level estimates averaged across all NO_x sources, and there is a positive bias associated with using a summertime relationship to reflect exposures across the year. However, modeling ozone formation in more detail was beyond the scope of our assessment.

4.2.3. Concentration-response functions

For $PM_{2.5}$, the concentration-response function for premature mortality was derived from a recent cohort study,[70] as documented in Levy, Baxter and Schwartz (2009).[69] Of note, this recent study specifically evaluated the likelihood of thresholds or other non-linearities in the concentration-response function, and found that a linear model throughout the range of ambient concentrations was by far the most likely model structure given the observed data. For morbidity, while a large number of outcomes have been characterized previously, we focus on a subset that are interpretable, span a range of severity, and may contribute significantly to monetized health damages. This includes hospital admissions for cardiovascular and respiratory causes, asthma-related

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[70] Schwartz, J.; Coull, B.; Laden, F.; Ryan, L., The effect of dose and timing of dose on the association between airborne particles and survival. *Environ Health Perspect* **2008,** 116, (1), 64-69.

emergency room visits, and minor restricted activity days (MRADs, days in which people had to reduce their activities due to symptoms but could still work). This should not be considered an exhaustive list of health endpoints and could potentially result in an underestimate of damages; however, monetarily, the impact of such underestimation would likely be small. Morbidity estimates are based largely on recent peer-reviewed meta-analyses, rather than Utah-specific studies.

For hospital admissions for cardiovascular causes, we rely on a recent meta-analysis [71] which combined 51 published studies to determine that cardiovascular hospital admissions increase by an estimated 0.9% per 10 $\mu g/m^3$ increase of PM_{10}. However, given that differences in health care systems among countries may influence an outcome like hospital admissions, utilizing a large number of non-U.S. studies to determine a concentration-response function for this outcome may not be appropriate. We therefore re-ran the meta-analysis restricted to the 33 estimates from U.S. studies, and determined a central estimate nearly identical to that above (a 0.97% increase in cardiovascular hospital admissions per 10 $\mu g/m^3$ of PM_{10}, slightly higher than the all-study value). We use a standard conversion between $PM_{2.5}$ and PM_{10} (a typical ratio of 0.6 based on evidence in the Particulate Matter Criteria Document) to derive a best estimate of a 0.16% increase in cardiovascular hospital admissions per $\mu g/m^3$ increase of $PM_{2.5}$, among individuals age 65 and older.

To derive an estimate for respiratory hospital admissions, we conducted a meta-analysis of the published literature, given a large number of studies and no recently published meta-analyses. The studies considered were taken from Levy et al. [72], from the EPA's BenMAP program, and from the Air Quality Criteria Document for Particulate Matter [73]. From the large number of studies available, we eliminated a subset of studies that could not be statistically pooled with other studies for a variety of reasons. These reasons included the application of statistical methods that were not comparable with other studies, use of a pollutant measure other than $PM_{2.5}$ (i.e., only considering acid aerosols or black smoke), consideration of specific respiratory diseases rather than all-cause respiratory hospital admissions, or evaluation of effects on children only. This does not imply that these studies did not represent good scientific evidence, but simply that they were not the best studies to combine to develop concentration-response functions using statistical meta-analysis techniques. If we pool all remaining studies [74,75,76,77,78,79,80,81,82,83,84] using inverse-variance weighting with statistical methods to

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[71] Committee on the Medical Effects of Air Pollutants *Cardiovascular Disease and Air Pollution*; Department of Health, United Kingdom: 2006.

[72] Levy, J. I.; Hammitt, J. K.; Yanagisawa, Y.; Spengler, J. D., Development of a new damage function model for power plants: Methodology and applications. *Environmental Science & Technology* **1999,** 33, 4364-4372.

[73] EPA *Air Quality Criteria for Particulate Matter*; EPA/600/P-99/002aF; National Center for Environmental Assessment, Office of Research and Development: Research Triangle Park, NC, October 2004, 2004.

[74] Anderson, H. R.; Bremner, S. A.; Atkinson, R. W.; Harrison, R. M.; Walters, S., Particulate matter and daily mortality and hospital admissions in the west midlands conurbation of the United Kingdom: associations with fine and coarse particles, black smoke and sulphate. Occupational & Environmental Medicine 2001, 58, (8), 504-10.

account for the possibility of true between-site heterogeneity, as done previously [65,85], the central estimate is a 0.2% increase in respiratory hospital admissions per 1 $\mu g/m^3$ increase of $PM_{2.5}$, applicable to all ages.

Another morbidity outcome of concern for $PM_{2.5}$ is ER visits among asthmatic individuals. As we did for respiratory hospital admissions, we gathered studies from Levy et al. [86] and the Air Quality Criteria Document for Particulate Matter [87]**,** and supplemented this database with an independent literature search. We were able to restrict our focus to U.S. studies for the formal statistical meta-analysis. In total, we found five studies that were suitable for meta-analysis [88,89,90,91,92]. As there is broad

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[75] Atkinson, R. W.; Bremner, S. A.; Anderson, H. R.; Strachan, D. P.; Bland, J. M.; de Leon, A. P., Short-term associations between emergency hospital admissions for respiratory and cardiovascular disease and outdoor air pollution in London. *Archives of Environmental Health* **1999,** 54, (6), 398-411.

[76] Burnett, R. T.; Cakmak, S.; Brook, J. R.; Krewski, D., The role of particulate size and chemistry in the association between summertime ambient air pollution and hospitalization for cardiorespiratory diseases. *Environ Health Perspect* **1997,** 105, (6), 614-20.

[77] Gwynn, R. C.; Burnett, R. T.; Thurston, G. D., A time-series analysis of acidic particulate matter and daily mortality and morbidity in the Buffalo, New York, region. *Environ Health Perspect* **2000,** 108, (2), 125-33.

[78] Gwynn, R. C.; Thurston, G. D., The burden of air pollution: impacts among racial minorities. *Environ Health Perspect* **2001,** 109 Suppl 4, 501-6.

[79] Hagen, J. A.; Nafstad, P.; Skrondal, A.; Bjorkly, S.; Magnus, P., Associations between outdoor air pollutants and hospitalization for respiratory diseases. *Epidemiology* **2000,** 11, (2), 136-40.

[80] Schwartz, J., Short term fluctuations in air pollution and hospital admissions of the elderly for respiratory disease. *Thorax* **1995,** 50, (5), 531-8.

[81] Schwartz, J., Air pollution and hospital admissions for respiratory disease. *Epidemiology* **1996,** 7, (1), 20-8.

[82] Schwartz, J.; Spix, C.; Touloumi, G.; Bacharova, L.; Barumamdzadeh, T.; le Tertre, A.; Piekarksi, T.; Ponce de Leon, A.; Ponka, A.; Rossi, G.; Saez, M.; Schouten, J. P., Methodological issues in studies of air pollution and daily counts of deaths or hospital admissions. *J Epidemiol Community Health* **1996,** 50 Suppl 1, S3-11.

[83] Thurston, G. D.; Ito, K.; Hayes, C. G.; Bates, D. V.; Lippmann, M., Respiratory hospital admissions and summertime haze air pollution in Toronto, Ontario: consideration of the role of acid aerosols. *Environ Res* **1994,** 65, (2), 271-90.

[84] Wordley, J.; Walters, S.; Ayres, J. G., Short term variations in hospital admissions and mortality and particulate air pollution. *Occupational & Environmental Medicine* **1997,** 54, 108-116.

[85] Levy, J. I.; Hammitt, J. K.; Spengler, J. D., Estimating the mortality impacts of particulate matter: what can be learned from between-study variability? *Environ Health Perspect* **2000,** 108, (2), 109-17.

[86] Levy, J. I.; Hammitt, J. K.; Yanagisawa, Y.; Spengler, J. D., Development of a new damage function model for power plants: Methodology and applications. *Environmental Science & Technology* **1999,** 33, 4364-4372.

[87] EPA *Air Quality Criteria for Particulate Matter*; EPA/600/P-99/002aF; National Center for Environmental Assessment, Office of Research and Development: Research Triangle Park, NC, October 2004, 2004.

[88] Lipsett, M.; Hurley, S.; Ostro, B., Air pollution and emergency room visits for asthma in Santa Clara County, California. *Environ Health Perspect* **1997,** 105, (2), 216-22.

[89] Norris, G.; YoungPong, S. N.; Koenig, J. Q.; Larson, T. V.; Sheppard, L.; Stout, J. W., An association between fine particles and asthma emergency department visits for children in Seattle. *Environ Health Perspect* **1999,** 107, (6), 489-93.

[90] Peel, J. L.; Tolbert, P. E.; Klein, M.; Metzger, K. B.; Flanders, W. D.; Todd, K.; Mulholland, J. A.; Ryan, P. B.; Frumkin, H., Ambient air pollution and respiratory emergency department visits. *Epidemiology* **2005,** 16, (2), 164-74.

[91] Schwartz, J.; Slater, D.; Larson, T. V.; Pierson, W. E.; Koenig, J. Q., Particulate air pollution and hospital emergency room visits for asthma in Seattle. *Am Rev Respir Dis* **1993,** 147, (4), 826-31.

[92] Tolbert, P. E.; Mulholland, J. A.; MacIntosh, D. L.; Xu, F.; Daniels, D.; Devine, O. J.; Carlin, B. P.; Klein, M.; Dorley, J.; Butler, A. J.; Nordenberg, D. F.; Frumkin, H.; Ryan, P. B.; White, M. C., Air quality

consistency across studies in the magnitude and significance of the effect, it makes sense to consider this an all-age effect. We consider a best estimate to be a 0.8% increase in asthma-related ER visits per $\mu g/m^3$ increase of $PM_{2.5}$.

Finally, we consider MRADs. There are a variety of respiratory symptom outcomes available in the literature, but we use MRADs given the fact that they capture a number of types of symptoms, have contributed significantly to monetized damages in the past, and to avoid possible double-counting. Only one published study considered MRADs [93], but this was a large nationally-representative sample of adult workers. Using inverse-variance weighting on six individual year estimates, we determine a 0.7% increase per $\mu g/m^3$ increase of $PM_{2.5}$.

For ozone, the concentration-response functions for mortality and morbidity are described in Ostro, Tran and Levy (2006) and are not replicated herein, but include time-series mortality (associated with short-term exposure rather than long-term exposure), respiratory hospital admissions, asthma emergency room visits, MRADs, and school loss days.

4.2.4. Baseline population data

As described in Levy, Baxter and Schwartz (2009), the core population data used in our prior externality modeling was based on the 2000 Census, with county-level baseline mortality rates taken from the CDC Wonder database. Characterizing externalities in future years and with consideration of morbidity outcomes requires application of additional information. Population growth was determined using data from Woods and Poole used in prior regulatory impact analyses, [94] which provides county-level population projections from 2000 to 2030 in five-year increments, for different age ranges and for the population as a whole. Thus, we can determine the at-risk population for each of the forecast years of interest, assuming linear interpolation between the five-year intervals characterized by Woods and Poole.

Population growth varies across counties and states, complicating our analysis, and we only have spatial characterization of exposure for a subset of power plants and pollutants. We apply population growth estimates at the county level for the particulate matter S-R matrix, at the state level for the ozone S-R matrix, and we use the relative differences between years for primary and secondary particulate matter health risks for directly modeled plants to scale up (or down) health impact estimates for indirectly modeled plants.

We also need to characterize the baseline incidence and prevalence of key health outcomes over time. For all outcomes, we assume that the age-specific rates will not change over time. However, as the age distribution of the population shifts over time,

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and pediatric emergency room visits for asthma in Atlanta, Georgia, USA. *Am J Epidemiol* **2000,** 151, (8), 798-810.

[93] Ostro, B. D.; Rothschild, S., Air pollution and acute respiratory morbidity: an observational study of multiple pollutants. *Environ Res* **1989,** 50, (2), 238-47.

[94] US Environmental Protection Agency *2006 National Ambient Air Quality Standards for Particle Pollution*; US Environmental Protection Agency: Washington, DC, 2006.

this will result in changes to the total population rates (often increasing the rates given an aging population). For cardiovascular and respiratory hospital admissions, rates are available by region (Northeast, Midwest, South, West) from the National Hospital Discharge Survey. For asthma emergency room visits, rates are similarly available by region from the National Ambulatory Medical Care Survey. Baseline incidence rates of both school loss days and MRADs are taken from articles in the peer-reviewed literature and are listed in Ostro, Tran and Levy (2006).

4.2.5. Valuation of health outcomes

For premature deaths, we use a value of statistical life (VSL) approach. This should not be taken as the value assigned to a life, but rather, as the aggregation of what a number of people are willing to pay for small risk reductions. In other words, if someone is willing to pay $50 for an intervention that would reduce their risk of dying by 1/100,000, their VSL would be $5 million ($50 divided by 1/100,000). Stated another way, if 100,000 people were all willing to pay $50 for this intervention, one life would be expected to be saved at a cost of $5 million.

As described in Levy, Baxter and Schwartz (2009), we calculate the VSL for premature deaths using EPA's recommended value, which was derived from multiple meta-analyses of the literature. EPA determined a central estimate of $5.5 million in 1999 dollars based on 1990 income distributions, with an uncertainty range from $1 million to $10 million. To determine appropriate values for future years, we need to take account of inflation as well as per capita real GDP growth, which influences how much people are willing to pay. As done by EPA, for all future years, we scale up using an elasticity value of 0.40 to account for per capita real GDP growth. We estimate the economic value in 2008 dollars in all future years, accounting for inflation from 1999 to 2008. In 2008, the estimated VSL for this study is approximately $8 million. Historical data for GDP growth per capita were taken from the U.S. Bureau of Economic Analysis, and we used the general consumer price index (CPI-U) to put VSL prices into 2008 dollars. We assumed 1.5% GDP growth per capita between 2009 and 2020, reflecting historical trends and lacking more detailed economic projections.

For morbidity outcomes, some values are based on what people are willing to pay to reduce the risk, while others reflect direct health care costs. For MRADs, we use EPA's willingness to pay values as described in Ostro, Tran and Levy (2006), accounting for real GDP growth per capita using an elasticity value of 0.14 as recommended by EPA for minor health outcomes. For the remaining morbidity outcomes, economic values are either based on the direct health care costs (cardiovascular or respiratory hospital admissions, asthma emergency room visits) or on the value of time for caregivers (school loss days). For economic values based on direct health care costs, we use the medical care CPI (CPI-MED-U) to scale from 1999 to 2008 dollars, and use these values for all model years. For the value of time for caregivers, we use the general CPI to scale from 1999 to 2008. More detail regarding the economic values used for morbidity and the nature of the evidence base is available in Ostro, Tran and Levy (2006).

4.3. Assumptions, caveats, & uncertainty

There are clearly numerous assumptions associated with our externality calculations, and the results should therefore be interpreted with caution. In general, externality estimates for particulate matter from the coal-fired power plants in Utah are based on peer-reviewed and published methods in which detailed plant-specific modeling was conducted. To give a sense of the magnitude of the uncertainties for these estimates, the paper by Levy, Baxter, and Schwartz (2009) quantified and propagated uncertainties in all aspects of the externality modeling. For the coal-fired power plants in Utah, the 5^{th} percentile estimates of monetized health damages per kWh of electricity generation were about a factor of 5 lower than the central estimates, while the 95^{th} percentile estimates were about a factor of 2.5 higher than the central estimates. Thus, even the well-characterized estimates have appreciable uncertainties, though with an equal likelihood that the values are overestimated as underestimated.

For most gas-fired power plants in Utah, no direct chemistry-transport modeling has been conducted, so we rely on extrapolations from previously modeled power plants. This generally yields population exposures per unit emissions on a par with coal-fired power plants, which is likely reasonable at first order given general similarities in plant locations, stack heights, and other basic characteristics affecting pollutant fate and transport. However, the one directly-modeled gas-fired power plant (Gadsby) did have significantly greater exposures per unit emissions than all coal-fired power plants, likely due to its location near population centers. The intake fraction regression models predicted somewhat lower values for the other gas-fired power plants, even in reasonably close proximity to Gadsby. To the extent that the intake fraction regression models may have missed local nuances associated with populations and topography near the gas-fired power plants, there may be biases in those estimates (which appear more likely to be downward biases based on available information). However, to place the significance of this issue in context, gas-fired power plants contribute minimally to the total health risks, although they do make appreciable contributions to the effects of selected scenarios. In addition, we were lacking primary PM emissions from multiple gas-fired power plants, and in general, primary PM emissions are more poorly characterized than NO_x or SO_2 emissions and should be considered more uncertain.

As described previously, ozone exposure modeling is based on a single paper in which relationships were derived for a single summertime month more than 10 years ago, so the uncertainties for ozone impacts are likely large and potentially highly biased. That said, there is some evidence that the annual ozone health effect is due to a high effect in the ozone season and minimal effect in other seasons, so there may be offsetting errors. Also, Tong uses NO_x emissions from both emission inventories and natural sources, but we use only the anthropogenic source emissions. Although we exclude the NO_x emissions from the natural sources in Utah, such additional information will further decrease the ozone intake fractions and therefore the contribution of ozone-related mortality to the total NO_x-related mortality.

While there are significant uncertainties associated with the concentration-response functions for mortality and morbidity outcomes, as well as for the economic valuation of health outcomes, the studies and methods we applied are comparable to those used by US EPA and in the peer-reviewed literature. Thus, while these elements have relatively large uncertainties, they represent standard practice for health impact assessment (as opposed to chemistry-transport modeling, in which more simplified assumptions were used given available resources).

A final category of uncertainty is related to the relatively small contribution that individual power plants make to ambient concentrations, especially for lower-emitting gas-fueled plants and receptors located at significant distances from the source. While it has been well established that particulate matter and ozone can have regional-scale impacts, the quantitative contributions are clearly more uncertain at long range. That said, the underlying atmospheric model did involve calibration with ambient monitoring data, which should help to limit model biases. More generally, even a small contribution to ambient concentrations would be expected to have an incremental health risk, given the basic logic behind a population concentration-response function. In other words, presuming that ambient concentrations are above any population threshold (as epidemiological evidence indicates for particulate matter and ozone), any change in ambient concentrations would change health risks in the population, as there is no theoretical basis for a “stepwise” concentration-response function in which only changes of certain magnitudes would influence population risk.

5. Water Use

5.1. Introduction

Water must be divided between multiple users, including agriculture, industry, and the public. Historically, a large majority of Utah's water has gone toward irrigation for agricultural users;[95] however, a growing population has caused some of the water use in the state to shift from agriculture to urban uses.[96] Utah has experienced continuous population growth for the last 150 years, and from 1990 to 2000, the state grew at the fourth fastest rate in the nation.[97] Projections from the Governor's Office of Planning and Budget predict that Utah's population will more than double in the next 50 years – growing from 2.3 million in 2000 to just under 6 million in 2050.[98] Historical population growth has already created a strain on the state's water supply, and projected growth over the next several decades "presents a major challenge to meet water demands."[99]

Much of Utah is classified as desert, receiving less than 13 inches of rainfall annually, and water in the state is a limited resource during all years.[100] Water becomes increasingly limited during periods of drought, which can last for a decade or more, and often have economic, social and environmental consequences that take years to be realized. The duration and severity of droughts have been measured in Utah since 1895. When taken in aggregate, the state of Utah has been in a period of major drought for 55 of the last 111 years.[101] Currently, the Division of Water Resources recommends that water suppliers increase their rate of investment in equipment and distribution systems in order to boost future supplies, and encourages Utah's water districts to focus on conservation of existing water supplies.

Table 5-1 shows the amounts of water withdrawn by various users in the state in 2005. As was mentioned above, the majority of water is withdrawn by agricultural users. Public supply and aquaculture are the second and third greatest users of water, respectively. Thermoelectric power generation is fourth, but still withdraws large volumes of water, estimated to be more than 58 million gallons per day, amounting to 65,000 acre-feet per year.[102]

[95] US Geological Survey. *Estimated Use of Water in the United States in 2000*. USGS Circular 1268. Released March 2004, revised April 2004, May 2004, February 2005. Available at: http://water.usgs.gov/watuse/data/2000/index.html
[96] See discussion of water transactions in the following sections.
[97] Utah Division of Water Resources. *Conjunctive Management of Surface and Ground Water in Utah*. Utah State Water Plan. July 2005. Page xi, 27.
[98] Governor's Office of Planning and Budget. Demographic and Economic Projections. 2008 Baseline Projections. Available at: http://governor.utah.gov/dea/projections.html
[99] Utah Division of Water Resources. *Conjunctive Management of Surface and Ground Water in Utah*. Utah State Water Plan. July 2005. Page 2.
[100] Utah Division of Water Resources. *Long-term Water Supply Outlook.* Available at: http://www.water.utah.gov/waterconditions/WaterSupplyOutlook/default.asp
[101] *Ibid*. Page 28.
[102] US Geological Survey. *Estimated Use of Water in the United States in 2005*. USGS Circular 1344. Released October 27, 2009. Available at: http://pubs.usgs.gov/circ/1344/

Table 5-1: Water Withdrawals in Utah by Sector.[103]

Sector	Freshwater withdrawals (million gallons per day)
Public Supply	607
Domestic	14
Irrigation	4,000
Livestock	18
Aquaculture	88
Industrial	35
Mining	5
Thermoelectric Power	58

Fossil-fired electric generators use large quantities of water for power plant cooling, and smaller amounts to increase efficiency of turbines and for pollution control. As a state's population grows, so does the demand for energy, increasing the demands on thermal generators and potentially requiring greater volumes of water for use in power plants. Conversely, declining demand for thermal generation, as achieved through energy efficiency or non-water intensive renewable energy programs, can lead to decreases in the rate of water use by thermal generators for power production. The displacement of thermal generators in favor of renewable sources of energy production such as wind or solar power may have a similar effect on water use.

This analysis examines the water co-benefit of EE and RE; since water consumption by thermal generating units is an externality of generation, avoided water use is the co-benefit of reduced generation. The monetary value of reduced water consumption is estimated as the marginal cost of water in Utah. These calculations are described below.

5.2. Estimating Water Use of Thermal Generating Units

To obtain a total quantity of water saved, the water consumption rate of the generating units in this analysis had to first be determined. The use of water at power plants is inconsistently reported and sparsely available, and therefore this study has estimated water consumption for some power plants based on values from the literature. Self-reported rates of water consumption in cubic feet per second were available from the Energy Information Administration (EIA) Form 767 for coal- and gas-fired units using steam turbines as a prime mover. The EIA discontinued the use of Form 767 in 2006, thus water consumption data are from 2005, the last year they were available. Form 767 also contained data on unit generation, and these numbers were combined with consumption rates to yield water consumption by unit in gallons per megawatt-hour (gal/MWh).

Water consumption data for gas turbines and combined-cycle units were not publicly available, and were estimated using information on unit cooling systems, combined with average water consumption rates found in a number of studies that examined the link

[103] US Geological Survey. *Estimated Use of Water in the United States in 2005*. USGS Circular 1344. Released October 27, 2009. Available at: http://pubs.usgs.gov/circ/1344/

between power generation and water use.[104] Information on the cooling systems for the three combined-cycle units was available from Title V Operating Permits issued by the Utah Division of Air Quality. Total water consumption was determined by estimating prime-mover consumption and adding this to the cooling water requirements. Combined-cycle units with evaporative cooling were assumed to require 100 gal/MWh,[105] while combined-cycle units with dry-cooling were assumed to use 10 gal/MWh.[106]

The remaining conventional units in the analysis used gas turbines as a prime mover, which use little to no cooling water. However, the Title V Operating Permits for these units also give information on installed technologies that use water either as a means for pollution control or to increase unit efficiency. For example, the Gadsby units 4-6 are equipped with water injection for NO_x control, while some of the West Valley units are equipped with water injection for NO_x control as well as evaporative spray mist inlet air cooling, which is intended to increase unit efficiency under increased ambient temperatures.[107]

Water consumption rates for the displaced generating units are shown in Table 5-2. Note that while this table shows the Currant Creek units as being combustion turbines, the units are in fact components of a single combined-cycle plant. The Currant Creek Power Plant was constructed in two phases. Phase 1 focused on installing and putting into service two simple-cycle gas-fired units, which began operation in 2005. Phase II added a steam cycle to Currant Creek, turning it into a combined-cycle power plant, which began commercial operation in March 2006. Water consumption for the Currant Creek units was estimated at 10 gal/MWh per unit, due to the fact that "Currant Creek's design incorporates an air-cooled condenser that uses only 10% of the amount of water that a similarly sized plant with wet cooling towers would require."[108]

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104 See, for example: Myhre, R. *Water & Sustainability (Volume 3): US Water Consumption for Power Production – The Next Half Century*. Electric Power Research Institute, Palo Alto, CA. 2002. Page viii. Clean Air Task Force. *The Last Straw: Water Use by Power Plants in the Arid West*. Prepared for the Energy Foundation and the Hewlett Foundation. April 2003. Page 3.; US Department of Energy. *Concentrating Solar Power Commercial Application Study: Reducing Water Consumption of Concentrating Solar Power Electricity Generation*. Report to Congress. Pages 4-5 and 11-13.; US Department of Energy. *Energy Demands on Water Resources*. Report to Congress on the Interdependency of Energy and Water. December 2006.

105 Myhre, R. *Water & Sustainability (Volume 3): US Water Consumption for Power Production – The Next Half Century*. Electric Power Research Institute, Palo Alto, CA. 2002. Page viii.

106 Dry cooling systems use considerable less water than wet cooling systems, and most estimates of water use from fossil plants with dry cooling found in the literature show water consumption to be zero. However, these estimates are given in gallons per kilowatt-hour. Indeed, a fossil unit utilizing dry cooling consumes a volume of water equivalent to "less than 10% of the consumption of an evaporative cooled plant," and thus consumption was calculated at 10% of 100 gal/MWh for a combined-cycle unit, or 10 gal/MWh. See: US Department of Energy. *Concentrating Solar Power Commercial Application Study: Reducing Water Consumption of Concentrating Solar Power Electricity Generation*. Report to Congress. Pages 4-5 and 11-13. While this is a paper largely about water consumption in concentrating solar power units, it provided information on thermal generating units for comparison purposes.

107 Utah Title V Operating Permits. Utah Division of Air Quality. Available at: http://www.airquality.utah.gov/Permits/Report_OPS_Permits_Issued.htm

108 Odis F. Hill and Robert Van Engelhoven. *Currant Creek Power Plant, Mona, Utah*. POWER Magazine. August 15, 2006. *Available* at: http://www.powermag.com/print/gas/Currant-Creek-Power-Plant-Mona-Utah_460.html

Finally, we estimate consumption at Mill Creek as 0 gal/MWh, as it uses a gas combustion turbine with dry NO_x controls, per the unit's Title V permit.

Table 5-2: Water Consumption Rate for Displaced Generating Units.

Plant Name	Unit	Prime Mover	Primary Fuel	Water Consumption Rate (gal/MWh)
Bonanza	1	ST	Coal	673
Carbon	1	ST	Coal	762
Carbon	2	ST	Coal	745
Currant Creek	CT1A	CT	Gas	10*
Currant Creek	CT1B	CT	Gas	10*
Gadsby	1	ST	Gas	6,761
Gadsby	2	ST	Gas	3,147
Gadsby	3	ST	Gas	1,092
Gadsby	4	GT	Gas	10*
Gadsby	5	GT	Gas	10*
Gadsby	6	GT	Gas	10*
Hunter	1	ST	Coal	642
Hunter	2	ST	Coal	620
Hunter	3	ST	Coal	621
Huntington	1	ST	Coal	630
Huntington	2	ST	Coal	634
Intermountain Power Project	1	ST	Coal	505
Intermountain Power Project	2	ST	Coal	460
Lake Side Power Plant	CT01	CC	Gas	100*
Lake Side Power Plant	CT02	CC	Gas	100*
Mill Creek		GT	Gas	0
Nebo Power Station	U1	CC	Gas	100*
West Valley Generation Project	U1	GT	Gas	10*
West Valley Generation Project	U2	GT	Gas	10*
West Valley Generation Project	U3	GT	Gas	10*
West Valley Generation Project	U4	GT	Gas	10*
West Valley Generation Project	U5	GT	Gas	10*

* Values are estimated.

Certain renewable energy generating technologies require the use of water, as shown in Table 5-3, below. Wind turbines require no water to generate electricity and are not included in this table. Solar photovoltaic systems require water to rinse away dust that may accumulate on the panels, while concentrating solar power (CSP) systems use solar-generated heat to power a steam-cycle electric generator, much like traditional fossil-fired units. In CSP units, some water is used for steam make-up and mirror washing, but much like fossil plants, the largest use of water in CSP units goes toward wet-cooling systems used to condense steam and complete the cycle.

Freshwater consumption in geothermal plants can vary significantly; from very little in high temperature dry steam or flash-steam plants, to fairly high consumption in low-temperature binary geothermal plants. In a binary system, geothermal fluids transfer heat to a closed-loop steam cycle with a low-boiling point hydrocarbon-based fluid. If the generating plant is wet-cooled, water is used to condense the steam. It is anticipated that much of the future geothermal fleet will be comprised of lower temperature binary systems, and thus we model a high water consumption rate for future geothermal facilities.

Table 5-3: Water Consumption Rate for Renewable Generating Technologies.

Renewable Technology	Water Consumption Rate (gal/MWh)
Solar Photovoltaic (PV)[109]	25
Wet cooled CSP Trough[110]	840
Dry cooled CSP Trough[111]	80
Wet cooled Binary Geothermal[112]	1,400

Rates of water consumption in gal/MWh were multiplied by the electric generation (MWh) of each of the units within the scenarios to determine total water consumption by both fossil and renewable energy technologies. The difference between consumption in the EE and RE scenarios determined the avoided water use. Finally, a range of prices for water in Utah was determined based on a review of the literature. These values were multiplied by avoided water usage to determine the total economic value of the co-benefits to water from EE and RE programs. Section 5.3 describes the marginal cost methodology used in this analysis.

5.3. Cost of Water in the West and in the State of Utah

Once avoided water consumption was determined, a water price had to be chosen in order to calculate the total economic value of water saved through efficiency and renewable strategies. The externality cost of water is undefined and likely highly variable by region, even within Utah. The economic value of a good is determined by a consumer's "willingness to pay," or to give up other goods or services (in this case, money) in order to obtain or retain that good. A marginal cost methodology was used to determine this willingness to pay for water in Utah, and therefore value the co-benefit of water savings from avoided generation in Utah. The marginal value of a good is simply the value of the next unit. When a good is abundant, the marginal value of each additional unit declines, because a buyer has a lower willingness to pay for those units. In an area experiencing water scarcity, however, each additional unit of water is more difficult to obtain and the cost to acquire the next unit of water is increasingly higher. This value of the next unit of water is the marginal price.

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109 Estimates of water consumption are based on similar estimates of water used to wash mirrors and panels in applications of concentrated solar power applications. See for example: US Department of Energy. *Concentrating Solar Power Commercial Application Study: Reducing Water Consumption of Concentrating Solar Power Electricity Generation*. Report to Congress.

110 US Department of Energy. December, 2006. Energy Demands on Water Resources: Report to Congress on the Interdependency of Energy and Water.Table B-1

111 University of Texas at Austin. April 2009. Energy-Water Nexus in Texas. Page12.

112 US Department of Energy. December, 2006. Energy Demands on Water Resources: Report to Congress on the Interdependency of Energy and Water.Table B-1

Observing prices for water in a market would be the easiest way to determine willingness to pay for that water. However, because water is a public good there has not historically been a robust and competitive marketplace in which water rights may be bought and sold. The nature of water as a public good usually demands that responsibility must be taken at some level of government to make sure that an adequate supply of water is received by those that need it. Because access to clean water is usually seen as an essential government function, water is often made available for basic consumptive purposes through subsidized prices, or even for free. The rate at which customers are charged by municipal water providers is therefore not an appropriate choice for the marginal value of water.

A system of "prior appropriation" for water rights has traditionally been used in western states, whereby the first person to use a quantity of water for a beneficial purpose has the right to use that same quantity of water in perpetuity without payment. Water rights in Utah are completely allocated, and in some regions over-allocated, meaning that any party wishing to acquire new or additional water rights must find another party that is willing to sell them. This has begun to occur with greater frequency over the past two decades, and this increase in market activity leads to a more useful estimate of the value of water.

An estimate of the marginal cost in Utah was achieved through a survey of a database of water transactions in the twelve western states[113] maintained by the Bren School at the University of California, Santa Barbara. The source for these transactions is the monthly trade publication *Water Strategist*, and its predecessor *Water Intelligence Monthly*, published by Stratecon, Inc. in Claremont, California. The issues used in this study summarize water transactions from 1987 to 2008 and provide information about the buyer, seller, purpose for which water was purchased (agriculture, urban, or environmental), type of transaction (purchase or lease), and the source of the water. Together, they form "the most comprehensive set of information available about water market trades in the western United States."[114] Figure 5-1gives a frequency distribution of the water transactions in Utah according to their value per acre-foot.

[113] "Western states" include Arizona, California, Colorado, Idaho, Montana, New Mexico, Nevada, Oregon, Texas, Washington, Utah, and Wyoming.

[114] Brown, Thomas. *The Marginal Economic Value of Streamflow from National Forests: Evidence from Western Water Markets*. US Forest Service, Rock Mountain Research Station. Fort Collins, Colorado. October 2004.

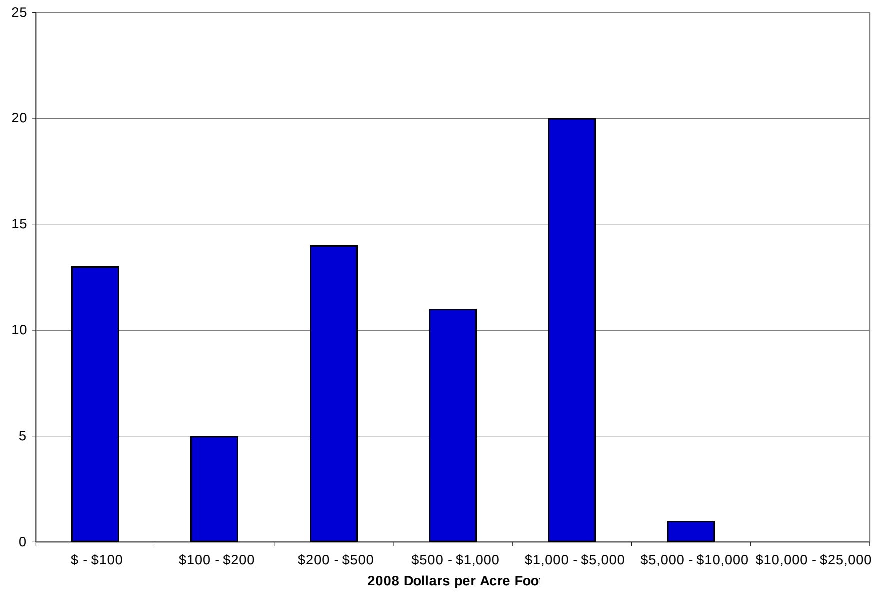

Figure 5-1: Frequency Distribution of Utah Water Transactions.

As mentioned above, as population increases and demand for water increases, water rights begin to move to their highest valued use. Figure 5-2 shows the number of transactions by value and purpose for which the water was purchased. "Ag-to-Urban" indicates, for example, that water rights shifted from an agricultural user to an urban user.

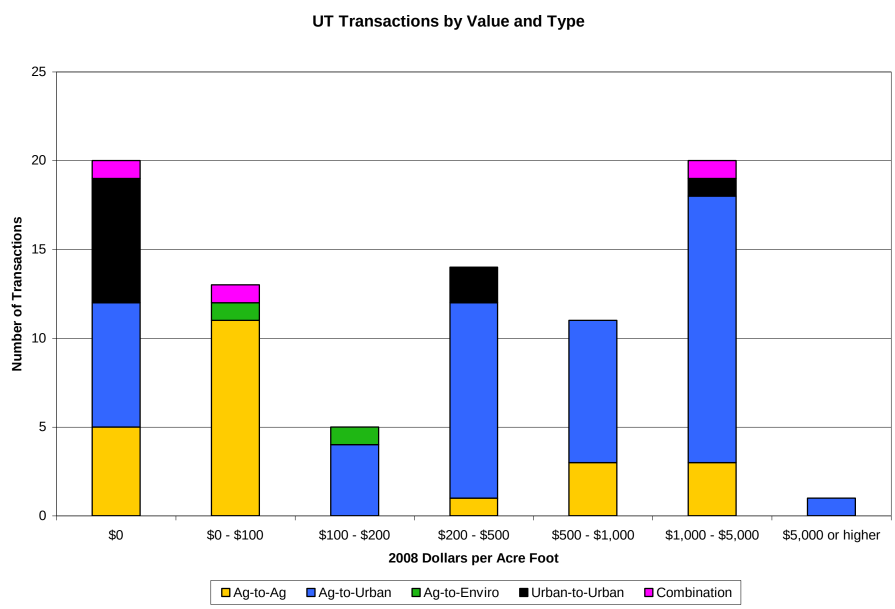

Figure 5-2: Utah Water Transactions by Value and Type.

Several different variables affect the price of water in these documented transactions, including, but not limited to, geography, volume of water transacted, time period, and the use for which the purchased water is intended. Variability of water prices suggests that it may be more appropriate to consider a range of values of the marginal price for water, rather than select a single value. In this research, we select the lower bound of water as the market rate of water, or what one would pay on the open market for a water right. At the upper bound, we select the marginal price of water from historic transactions.

- The lower bound of this range is set at $520 per acre-foot, the median value of historic Utah water transactions. This value is representative of a price that might likely be paid to obtain the rights to existing water in Utah in the market today.
- The marginal price of water is estimated at $5,182 per acre-foot, which represents a known historical willingness-to-pay. In this transaction, the water rights to the Beaver Creek were purchased in 1999 from an irrigator (an agricultural user) by a developer (an urban user) to provide services to a 60-condominium development, with the rest being held for future residential development.

The upper bound of a range of water values might then be the price that is paid to obtain additional water in a region of the state that is water-scarce. This project did not distinguish between geographical regions of the state or water scarcity status. An online water rights exchange suggests that the marginal price of water estimated above ($5,182) is not an unreasonable value for current water values in Utah.

At the time of this writing, sellers throughout Utah were offering to sell units of water at prices ranging from $1,000 to $10,000 per AF, with a majority of the asking offers ranging between $5,000 and $7,000 per AF.[115] The closest seller to an existing plant was offering 100 AF at $7,000 / AF in the same water district as the new Currant Creek combined cycle plant.

[115] Water Rights Exchange. Accessed March 19, 2010. Available online at http://waterrightexchange.com/

6. Scenario Design and Results

In this research, we developed four over-arching scenario categories (with sub-scenarios) to explore the influence of reduced demand, new renewable resources, or replacing inefficient generators. The scenario categories are:

1. **Baseline**, or business-as-usual (BAU) scenario, in which demand grows at a rate estimated by PacifiCorp in 2008, a major Utah utility. In this scenario, increasing peak demand is met by new in-state combined-cycle gas units.
2. **Energy efficiency and demand response** scenarios, that reduce both total energy demand over time, and shave peak load requirements through demand response. Three energy efficiency scenarios are explored, from relatively modest to aggressive reductions.
3. **Renewable energy** scenarios, that reduce requirements for new and existing fossil generation by harnessing renewable resources. In this study, we explore three wind build-out options, two aggressive solar photovoltaic options, two central station concentrating solar power (CSP) options, and one geothermal scenario. In the solar and wind cases, the amount of renewable energy is arbitrarily fixed at a moderate penetration of 880 MW by 2020, and the geothermal scenario is fixed at 440 MW by 2020.
4. **Replacement** scenarios, where approximately one-third of the most harmful generators are replaced. We build two scenarios: one in which select coal units are replaced by moderate demand-side management and efficient gas-fired units, and one in which the efficiency is complimented by two wind farms and a concentrating solar plant.

A realistic alternative energy future for Utah would probably comprise elements of each of these scenarios, reducing demand through cost-effective energy efficiency and demand response strategies, diversifying energy supply with several different renewable energy options, and replacing older, inefficient generators with a combination of resources. Such a scenario was not deemed in the scope of this research. This research does not propose an energy plan, but is built to support planning exercises by estimating the impact of a moderate increase in alternative energy resources. The replacement scenarios do not reflect an optimized solution or specific recommendation; rather, they are illustrative of the social and environmental costs of operating the current fleet and the benefits that could be realized through replacement.

6.1. Baseline Scenario

The baseline scenario analyzes what would occur between 2008 and 2020 if load requirements and demand were to continue to grow according to BAU assumptions. Because this scenario represents the baseline against which all other scenarios are measured, the scenario does not assume emissions reductions, additional efficiency beyond that predicted by PacifiCorp in 2008, or new renewable energy in-state.

In this scenario, load growth follows estimates from PacifiCorp, made available by request in 2008.[116] PacifiCorp provided estimated monthly non-coincident peak load requirements for all states in their service territory for 2009 through 2023. To translate peak load requirements into estimated hourly load profiles, we determine the linear relationship between each year's monthly peaks and the following year's peaks, a slope and offset through twelve points. Each year's slope and offset are used to scale the reference year (2007-2008) hourly load profile, discussed in Section 3.3.1, through 2020.

In the baseline scenario, new growth is met with additional combined cycle and combustion gas turbines (detailed in section 6.5). The addition of gas-fired generators in the base case is a conservative estimate for the purposes of this analysis, and in line with current trends. If the analysis met future demand with coal-fired generation, baseline externalities would rise dramatically (coal plants are disproportionately high impact). Displacing potential future coal with EE and RE would then result in universally high co-benefits. This analysis attempts to illustrate the impact of EE and RE in a future in which externalities are valued or internalized. In such a future, new conventional generation would likely be gas-fired.

Results from the generation analysis are shown in Table 6-1 and Figure 6-1. Generation during the study period is projected to total approximately 47,230 GWh, with coal generation amounting to 83% of all energy supplied. At the end of the study period, in 2020, coal generation has not decreased significantly, and gas generation has nearly doubled, eventually supplying 27% of all fossil power production in Utah.

Table 6-1: Fossil generation (GWh) in Utah during the reference period (2007-2008) and at the end of the study period (2020-2021)

	Fossil Generation in Utah, GWh		
2007-2008	**Coal**	**Gas**	**Total**
Reference	38,988	8,240	47,228
2020-2021			
Baseline Load Growth	39,486	14,778	54,264

116 It should be noted that the load growth estimates obtained from PacifiCorp are dated from 2008, and may pre-date long-term changes in demand brought about by the economic downturn starting in 2008.

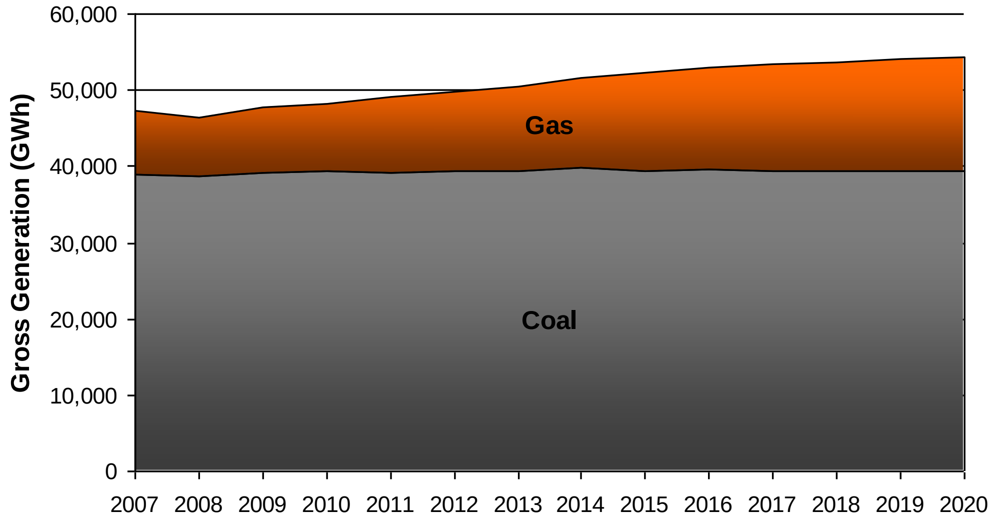

Figure 6-1: Annual gas and coal generation in the baseline scenario, in GWh.

There are no co-benefits calculated for the baseline scenario; however, we calculate externalities to compare against EE and RE scenarios. The externality cost of the system today is divided into mortality and morbidity, and the cost of water. Health impacts are experienced both in Utah and in downwind states; therefore we show first total health impacts and then impacts experienced only in Utah.

Table 6-2 shows the value of the baseline externalities. Premature deaths from fossil generation in Utah today are valued at $1,612 million of which $222 million are experienced within Utah's borders. Healthcare costs for metrics explored here amount to $32 million, with about half of the costs experienced within Utah's borders. We value water consumed by Utah electric power producers at between $38 and $469 million, based on the range for the value of water derived in Chapter 5. In total, we estimate a total externality cost between $1.68 and $2.03 billion dollars from generation in Utah today.[117]

As population increases and generation rises to meet demand, more residents in and out of Utah are exposed to criteria pollutants. In 2020, at the end of the study period, Mortality is valued at $2,337 million. Water use does not increase substantially, because new gas-fired generators have low water consumption rates. Total externality costs rise to between $2.4 and $2.8 billion by 2020.

[117] All generation, emissions, and externality values reported in this chapter are the median value of all Monte Carlo runs (see Section 3.4.3)

Table 6-2: Annual externality costs for baseline scenario relative to reference (2007-2008) and at end of study period (2020-2021). Externality cost of mortality, morbidity, and water, in millions of 2008 dollars per year. In health valuation, bold values are totals, values in parentheses are Utah only.

	Health Costs and Valuation, Million 2008$ per year All (in Utah)		Externality Cost of Water (Low - High)	Total Externality Cost (Low - High)
2007-2008	**Mortality**	**Morbidity**		
Reference Case	**$1,612** ($222)	**$32** ($16)	**$38 - $383**	**$1,683 - $2,027**
2020-2021				
Baseline	**$2,337** ($339)	**$41** ($21)	**$40 - $401**	**$2,418 - $2,779**

6.2. Energy Efficiency and Demand Response Scenarios

Historically, Utah has had one of the fastest growing energy demands in the nation. In the baseline scenario, load grows between 1-4% per year from 2009 to 2020—nearly 26% in twelve years. While this baseline assumption may have changed due to the recent economic downturn, it does not change that Utah's rapid growth in electrical consumption has significant room for efficiency programs across all sectors. A number of recent reports have found a significant potential for significant cost-effective energy efficiency in the state of Utah.

A 2006 Western Governors Association (WGA) report consolidates efficiency and demand-side management reports from several western states, and estimates that cost-effective efficiency measures could reduce demand by 0.5 to 2% per year, and finds feasible 20% reductions from projected 2020 levels throughout the west. Using the 2008 load growth estimates, this 1.4% energy efficiency per year rate would still entail growth in Utah's energy requirements. A report specific to the state of Utah in 2002 identified an economic potential of nearly 2,309 GWh per year of efficiency by 2006,[118] an ambitious goal which was not realized.

On April 26, 2006, Governor Huntsman released a comprehensive energy efficiency savings plan for the State of Utah, with a target of meeting a 20% reduction from baseline energy use by 2015. An executive order, signed one month later, codifies this objective for state facilities and sets the target for the state as a whole.[119]

Finally, a 2008 report by the Southwest Energy Efficiency Project (SWEEP) recommends a detailed series of policy options to capture energy efficiency potential. The report finds a technical potential of 6,200 GWh of savings by 2015 (an 18% reduction from baseline) and 10,319 GWh by 2020 (a nearly 26% reduction from the

[118] Nichols, D. and D. Von Hippel. 2001. An Economic Analysis of Achievable New Demand-Side Management Opportunities in Utah. Report prepared for the Systems Benefit Charge Stakeholder Advisory Group to the Utah Public Service Commission. Boston, MA: Tellus Institute.

[119] Utah State Executive Order 2006/004. Improving Energy Efficiency. Governor Jon Huntsman, May 30, 2006. Available online at: http://www.energy.utah.gov/energy/docs/energy_executive_order.pdf

projected baseline). The report projects achievable energy savings rising from 0.5% in 2006 through 1% in 2011, and maintaining that level of reductions thereafter.[120]

In considering demand-side management techniques, utilities often find significant benefit in demand response (DR) programs, that reduce requirements for capacity, rather than energy. DR often entails reducing peak load requirements for industrial and commercial, and occasionally residential, locations using combinations of peak pricing mechanisms and direct load controls. DR programs target the most costly peak hours of production and benefit ratepayers by reducing requirements for expensive new generation or wider reserve margins. SWEEP suggests that, historically, utilities have maintained a ratio of approximately 0.3 to 0.4 MW of DR for every GWh/year of reduction. We use these assumptions in constructing a combined EE / DR set of scenarios.

The scenarios considered here are:

- **EE, SWEEP:** Reductions in total energy requirements begin at 0.5% per year statewide, increasing to 1% per year by 2011, and maintaining 1% per year through 2020. Ratio of DR to EE is 0.33 MW peak reductions per GWh EE reduction.
- **EE, 2% per year:** Reductions begin at 0.5% per year statewide, increasing to 2% per year by 2015, and maintaining 2% per year through 2020. Ratio of DR to EE is 0.40 MW peak reductions per GWh EE reduction.
- **EE, 3% per year:** Reductions begin at 0.5% per year statewide, increasing to 3% per year by 2016, and maintaining 3% per year through 2020. Ratio of DR to EE is 0.40 MW peak reductions per GWh EE reduction.

Energy efficiency is modeled as a flat percentage reduction from each hour based on the annual expected percent savings. Typically, EE measures have a limited lifespan, between 8 to 20 years. An average measure life of 12 years is considered a standard approximation; therefore, during this analysis period, the efficiency measures modeled by the reduction do not expire and continue to accumulate. DR is modeled as a MW reduction off the highest peak hour. For example, after applying the SWEEP energy efficiency assumptions, the maximum peak in 2015 is 5,778 MW. We model DR as reducing this peak to 5663 MW (a reduction of 115 MW) and assume that no hour in 2015 may exceed this peak. The same reasoning is applied to the other scenarios accordingly. Table 6-3 below, shows the annual assumed reduction for each scenario in three key years, the cumulative reduction from baseline by 2020, the annual and cumulative energy reduction required to meet the target, and the associated peak reductions associated with each scenario.

[120] Geller, H., S. Baldwin, P. Case, K. Emerson, T. Langer, and S. Wright. October, 2008. Utah Energy Efficiency Strategy: Policy Options. Available online at: http://www.aceee.org/transportation/UT%20EE%20Strategy%20Final%20Report%20-%2010-01-07.pdf

Table 6-3: Assumptions for energy efficiency scenarios, annual and cumulative reductions from baseline, and demand response characteristics.

Annual Reduction (%)	**2010**	**2015**	**2020**
SWEEP	0.90%	1.00%	1.00%
2% EE	1.00%	2.00%	2.00%
3% EE	1.30%	2.80%	3.00%
Cumulative Reduction (%)	**2010**	**2015**	**2020**
SWEEP	2.35%	7.00%	11.50%
2% EE	2.54%	9.89%	18.43%
3% EE	2.93%	12.88%	25.02%
Annual Reduction (GWh)	**2010**	**2015**	**2020**
SWEEP	256	349	361
2% EE	284	655	659
3% EE	367	889	915
Cumulative Reduction (GWh)	**2010**	**2015**	**2020**
SWEEP	673	2317	4093
2% EE	728	3272	6561
3% EE	838	4260	8907
Demand Response (MW)	**2010**	**2015**	**2020**
SWEEP	84	115	119
2% EE	113	262	264
3% EE	147	356	366

Table 6-4 shows expected generation today and at the end of the study period. Efficiency primarily drives down natural gas-fired generation, and coal generation does not change significantly in the less aggressive energy efficiency scenarios. The displacement of natural gas, rather than coal, is because (a) even as Utah decreases its own consumption, it remains a net exporter of low-cost energy (coal-fired generation), and (b) gas is the marginal fuel in Utah in nearly every hour, and will therefore be displaced preferentially to coal when available.

As EE is ramped to 3% energy efficiency per year, coal generation begins to decline moderately, dropping to 38,414 GWh (over 1,000 GWh below the baseline in 2020). At higher levels of EE and demand response, in-state demand is sometimes reduced to a point where, historically, some amount of coal generation is not required. Therefore, it is estimated that higher penetrations of EE will reduce very modest amounts of Utah coal generation, while lower penetrations will primarily impact exclusively gas-fired generators.

Table 6-4: Fossil generation (GWh) in Utah at the end of the study period (2020-2021)

	Fossil Generation in Utah, GWh*		
2020-2021	**Coal**	**Gas**	**Total**
Baseline	39,500	14,800	54,300
EE (SWEEP)	39,600	11,200	50,800
EE (2% per yr)	39,400	9,000	48,500
EE (3% per year)	38,400	7,500	46,000

**Values rounded to nearest hundred GWh*

The externality cost of the energy efficiency scenarios is not significantly lower than the baseline scenario. Table 6-5 shows externality values for the baseline and scenarios in 2020-2021.

Table 6-5: Externality costs for baseline and energy efficiency scenarios at end of study period (2020-2021). Externality cost of mortality, morbidity, and water, in millions of 2008 dollars per year. In health valuation, bold values are totals, values in parentheses are Utah only.

2020-2021	Health Costs and Valuation, Million 2008$ per year All (in Utah)				Externality Cost of Water (Low - High)	Total Externality Cost (Low - High)
	Mortality		Morbidity			
Baseline	**$2,337**	($339)	**$41**	($21)	**$40 - $401**	**$2,418 - $2,779**
EE (SWEEP)	**$2,317**	($334)	**$41**	($21)	**$39 - $393**	**$2,397 - $2,751**
EE (2% per yr)	**$2,291**	($329)	**$41**	($21)	**$39 - $393**	**$2,372 - $2,725**
EE (3% per year)	**$2,234**	($316)	**$40**	($20)	**$38 - $375**	**$2,312 - $2,649**

The co-benefits are estimated as the difference between the externality cost of each scenario and the baseline, per unit energy (in this case, MWh). Table 6-6 shows the co-benefits of the energy efficiency scenarios. The SWEEP energy efficiency scenario saves approximately $5.9-8.3 per MWh by 2020, while a more aggressive efficiency scenario can offset $12.8-16.3 for each MWh of avoided generation. As noted previously, increasingly aggressive efficiency may displace some amount of coal generation, resulting in larger co-benefits on a per-MWh basis.

Table 6-6: Value of co-benefit for efficiency scenario at end of study period (2020-2021). Co-benefits in avoided dollars per MWh of avoided generation. In health valuation, bold values are totals, values in parentheses are Utah only.

2020-2021	Health Co-Benefits, 2008$ per MWh All (in Utah)				Avoided Cost of Water (Low - High)	Total Co-Benefit (Low - High)
	Mortality		Morbidity			
EE (SWEEP)	**$5.63**	($1.50)	**$0.05**	($0.03)	**$0.2 - $2.1**	**$5.9 - $7.8**
EE (2% per yr)	**$7.77**	($1.66)	**$0.07**	($0.03)	**$0.1 - $1.4**	**$8.0 - $9.3**
EE (3% per year)	**$12.32**	($2.81)	**$0.20**	($0.10)	**$0.3 - $3.1**	**$12.8 - $15.6**

6.3. Renewable Energy Scenarios

6.3.1. Wind Energy

Utah has moderate wind energy potential and select areas in the state are considered highly favorable for wind development. A 2006 study for the DOE estimated an achievable capacity of 700-2000 MW in the state,[121] and in 2008, Edison Mission brought 18.9 MW (nine 2.1 MW turbines) of wind online in at the mouth of the Spanish Fork Canyon, east of Utah Lake. In the fall of 2003, First Wind's Milford Phase 1 wind farm came on line in Beaver County with 203 MW of capacity.

[121] Mongha, N., ER Stafford, CL Hartman. May, 2006. US Department of Energy, Energy Efficiency and Renewable Energy. An Analysis of the Economic Impact on Utah County, Utah from the Development of Wind Power Plants. http://www.windpoweringamerica.gov/pdfs/wpa/econ_dev_jedi.pdf

In 2001, the Utah Geological Survey began collecting data from a state-sponsored anemometer loan program. Data from 20 and 50 meter (65 and 164 feet) towers are available for sites throughout the state, including ridge tops, plains, and canyon mouths. Filtering by average annual wind speed, we collected data for three potential sites. Two of these sites are in Utah, and were chosen because they have reported average annual wind velocities exceeding 12 mph at the measured hub heights.[122] The last site in Wyoming is near existing Pacificorp wind development sites. The sites included:

- **TAD North:** Tooele Army Depot in eastern Tooele County (north-central Utah), 30 miles SW of Salt Lake City, UT. Anemometer data from 2007 were obtained from 20 meter towers.
- **Porcupine Ridge:** Northern Summit County, 45 miles NE of Salt Lake City, UT. Anemometer data from 2007 were obtained from 20 meter towers.
- **Medicine Bow, WY:** 2008 data was obtained from anemometers located near Medicine Bow / Kroenke, Wyoming, a proxy site near existing PacifiCorp wind farms. This site represents the patterns of wind generation that could be expected from expanded wind operations in Wyoming.[123]

The data from each site were scaled to 80 meter equivalent wind speeds by the Utah State Energy Program, and resampled to one hour average wind speeds by Synapse.

The power output from a wind turbine is proportional to the cube of the wind speed. Turbines are designed for different wind applications, optimized to harness sporadic high wind speeds, consistent lower wind speeds, or a variety of conditions. In modern turbines, power output saturates at a specific wind speed, and the turbine will maintain this output until wind speeds exceed safe velocities, at which point turbines stall or apply breaks to prevent damage. The shape of this behavior is the power curve for a turbine, describing the expected output at any given wind speed. For the purposes of this project, we used the output characteristics of a GE 2.5xl turbine, a 2.5 MW capacity turbine with a 100 meter (328 ft) diameter, sweeping 7854 square meters (84,500 square feet).[124] The turbine would normally be mounted at heights from 50 to 75 meters (246 to 328 feet, respectively). The approximate power curve of the turbine is found in Figure 6-2.

The expected power output from each site was determined by running the wind speeds through a look-up table representing the shape of the power curve. This transformation yields an estimated gross power output as if a 2.5 MW turbine were mounted at an 80 meter hub-height. The median hourly output (as well as 33rd and 66th percentiles) from each site are shown in Figure 6-3; median monthly output is shown in Figure 6-4.

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[122] Wind turbine sites are classified by average annual wind speeds, with classes ranging from Class 1 (Poor) to Class 7 (Superb). Speeds exceeding 12 mph on average are considered at least marginal sites. Wind speeds (and thus suitability for wind capture) are often greater at higher hub-heights.

[123] The Medicine Bow wind proxy in this research represents a realistic near-term wind expansion site, but unlike the other projects in this study is not located in Utah, and may be subject to a different set of transmission constraints than the projects in Utah. It is feasible that, because of transmission dynamics in the WECC region, Wyoming wind is primarily delivered to the Northwest, rather than to Utah.

[124] http://www.gepower.com/prod_serv/products/wind_turbines/en/downloads/ge_25mw_brochure.pdf

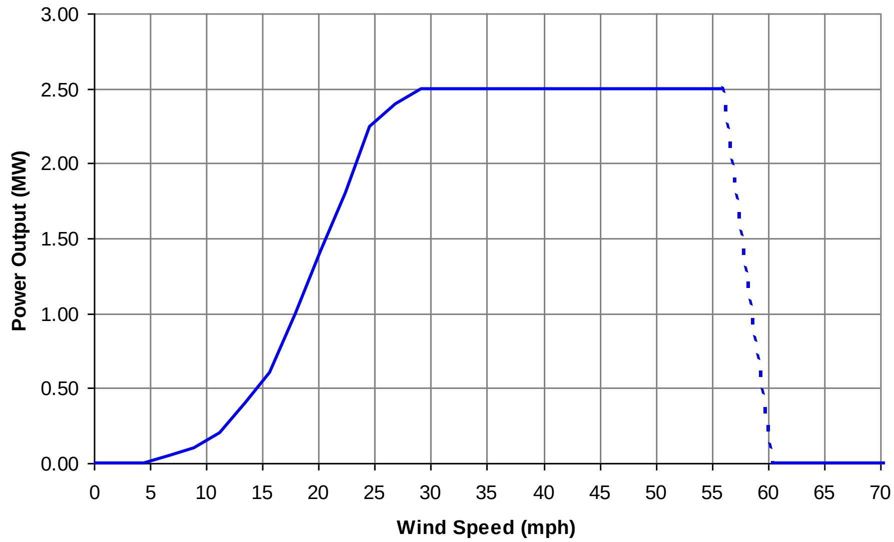

Figure 6-2: Power curve for GE 2.5xl turbine. Replicated from public specifications, see text for reference.

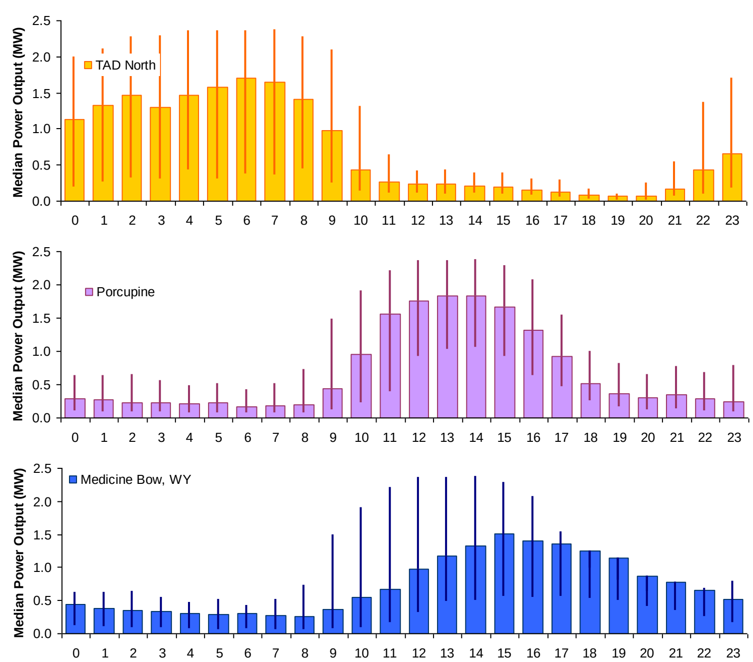

Figure 6-3: Hourly median power output by site. Error bars represent 33rd and 66th percentile around the median.

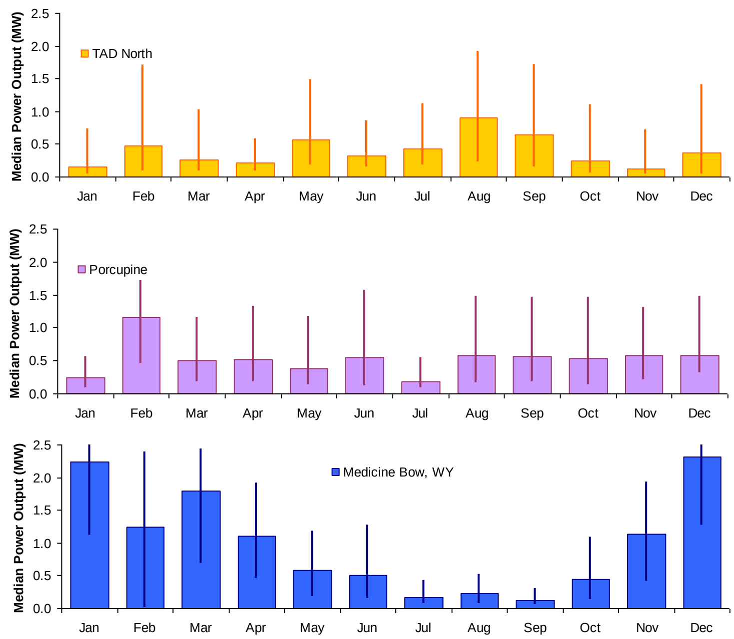

Figure 6-4: Monthly median power output by site, as if turbines were mounted at simulated 80-meter hub heights. Error bars represent 33rd and 66th percentile around the median.

It should be noted that the wind time series have very different characteristics. The TAD North and Porcupine locations both maintain high wind speeds throughout the year (with winter storms driving a February peak), but the TAD North site peaks overnight, reaching maximum output in early morning hours (between midnight and noon) while the Porcupine site produces during the day, peaking in the early afternoon. The Medicine Bow location is highly seasonal, with the fastest wind speeds through the winter, and peaking through afternoon hours.

A future balanced portfolio of wind might choose to erect turbines at different types of sites, reducing opportunities to have all the sites non-operational at the same time. An illustrative mixed portfolio with wind and concentrating solar power was modeled as one of the coal replacement scenarios, discussed later in this chapter.

In this study, we assumed a moderate penetration of wind power built on behalf of Utah, a total of 880 MW by 2020 (or a linear increase of 80 MW per year after 2011). This value is chosen to represent a non-transformative amount of wind power, altering dispatch but not large enough to require significant new resources for integration. To represent the 880 MW of capacity, we scale the transformed output from 2.5 MW (a single turbine equivalent) to 880 MW linearly. Each hour of output is similarly transformed. To estimate the impact of this new renewable energy on conventional generation in Utah, we subtract the expected hourly output of the wind turbines from the hourly demand of Utah. This simulates the wind as a must-take resource, dispatched directly into Utah's grid before all other conventional generation.

We assume that there are no emissions from wind power sites, and that wind energy uses no water for operational purposes.

The equivalent gross capacity factors and power output from each of the wind sites are given in Table 6-7.

Table 6-7: Potential gross capacity factor at 80 meter hub heights, and expected gross power output in simulation by year.

	Gross Capacity Factor (at hub height)	Gross Power output in 2010 (GWh)	Gross Power output in 2015 (GWh)	Gross Power output in 2020 (GWh)
TAD North	35.9%	253	1,516	2,779
Porcupine	37.6%	264	1,584	2,905
Medicine Bow	42.6%	297	1,784	3,271

6.3.2. Solar Photovoltaic and Concentrating Solar Power

Southern Utah has high solar energy potential. In this study, we explore the impacts of photovoltaic (PV) arrays and large, central station concentrating solar power (CSP) plants.

PV arrays are typically comprised of arrays of solid cells that convert sunlight into electricity. Such arrays could be the equivalent of the large 14 MW array erected at Nellis AFB (Nevada) in 2007,[125] or a state or utility sponsored program to increase residential and commercial rooftop PV availability, such as the California Solar Initiative with a target of 1,800 MW of PV.[126]

CSP has three commercial configurations: (a) parabolic troughs, where rotating, curved mirrors reflect sunlight onto long fluid-filled tubes, which in turn drive steam turbines; (b) so-called "power towers" where fields of mirrors orient to reflect sunlight onto a fluid-filled tank on a tower, which in turn drives a steam turbine; or (c) stirling solar, in which concentrated light is focused onto one end of a stirling engine, which turns a shaft based on the heat differential between cool and warm compartments. The 64 MW Nevada Solar One project[127] is an example of an operating solar trough plant, while the experimental (and now discontinued) Solar Two project in California[128] and the 10 MW commercial Planta Solar 10 project in Spain are early examples of the solar tower concept. In the US, two large-scale stirling solar projects will potentially break ground in California in 2010 (the Imperial Valley [Solar 2] and SES Solar One projects).

From a displaced emissions and generation analysis, the primary difference between these solar projects are on the hours of the day in which they are most active, and hence the generation which they would be expected to displace. All solar projects operate in sunlight, but differ significantly based on how light is received and if they have

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[125] Nellis Air Force Base. Nellis activates Nations largest PV Array. December 18, 2007. http://www.nellis.af.mil/news/story.asp?id=123079933

[126] California Public Utilities Commission. California Solar Initiative. http://www.gosolarcalifornia.org/csi/index.html

[127] Nevada Solar One. Acciona Power. http://www.acciona-na.com/About-Us/Our-Projects/U-S-/Nevada-Solar-One.aspx

[128] Solar Two Project. http://ucdcms.ucdavis.edu/solar2/history.php

energy storage available. PV systems have no intrinsic storage capacity, but will produce energy under overcast conditions with indirect sunlight. PV systems that are able to track the sun can harness more energy during dawn and dusk hours than fixed-plate systems.[129] Concentrating troughs and towers track the sun but require exposure to direct sunlight. The systems warm a fluid, which can have anywhere from a few to 15 theoretical hours of energy storage capacity, depending on design. Stirling systems also require direct sunlight, and are highly efficient, but have no storage capacity. For this analysis, we choose two PV scenarios and one CSP option in a wet-cooled and dry-cooled configuration. We did not choose a stirling system because the output would be expected to closely match the output from a tracking PV system, assuming low cloud cover. The four solar scenarios are:

- **Flat plate PV:** A flat plate photovoltaic collector lying in a horizontal orientation, consistent with a simple, low-cost commercial or industrial rooftop application, such as on warehouses and retail locations;
- **Single-axis track PV:** A PV array oriented 15 degrees south (from the horizontal), tracking solar position, approximating the output from a single or series of utility-scale PV systems;
- **Parabolic trough CSP with wet cooling:** a solar farm configuration similar to that seen in the Nevada Solar One project, in Boulder NV, built to provide six hours of storage;
- **Parabolic trough CSP with dry cooling:** a solar farm configuration similar to the wet tower-cooled scenario above, but with the ability to cool boiler steam without extensive water consumption.

Solar potential for PV systems was obtained using the National Renewable Energy Laboratory (NREL) PV Watts calculator for Cedar City, Utah.[130] The PV Watts system draws on meteorological station data from the National Solar Radiation Data Base. Data in this system are based on the second derived typical meteorological year (TMY2),[131] which chooses the best representative month for a typical year between 1961 and 1990. The PV Watts calculator derives hourly electrical output from a PV array of a defined size in a particular orientation. The results are not affected by scale (size of the defined PV array). In this study, a one-watt array was chosen as a proxy system, and scaled linearly to the equivalent size anticipated in each year of the study (880 MW by 2020).

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[129] Single-axis tracking solar farms are comprised of hundreds to thousands of PV arrays. Each array is mounted on a rotating axis which tilts from east to west, tracking the movement of the sun. The additional tracking allows higher direct exposure during the morning and afternoon, extending the effective time in which a PV array can produce power. The largest solar PV array erected to date is a single-axis track system at Nellis Air Force Base in southern Nevada; 72,000 panels, each 200 watts, produce 14 MW at peak.

[130] National Renewable Energy Laboratory. 2008. PV Watts Version 1 Calculator. http://rredc.nrel.gov/solar/calculators/PVWATTS/version1/

[131] National Renewable Energy Laboratory. National Solar Radiation Data Base. http://rredc.nrel.gov/solar/old_data/nsrdb/tmy2/

Output for a simulated CSP was estimated using the NREL Solar Advisor Model (SAM), with output modeled for Cedar City, Utah.[132] We used default settings for a 100 MW parabolic trough system with six hours of storage. The model returns expected hourly output in MW. Strictly speaking, CSP operations with storage are dispatchable to limited extent, however there is little information to suggest exactly how these resources would be dispatched, if at all, and which price signals they would use to alter or optimize performance. In this case, we assume that the SAM output represents typical operations in this environment.

CSP systems have the potential to be significant water consumers. Photovoltaic systems do not generally require water to operate, but must be washed regularly to maintain efficiency. In our analysis, we assume a consumption rate of 25 gallons per MWh to wash solar PV arrays (see Section 5.2). The modeled CSP systems run by heating a transfer fluid, which in turn heats water to steam. Steam boiler operations require water for both powering the boiler and for cooling. It is estimated that wet cooled CSP operations will use approximately 840 gallons per MWh, while dry cooled systems require approximately 80 gallons per MWh (see Section 5.2). This water consumption would presumably target the same water supplies used by conventional generation, and is therefore factored into the externality cost of the scenario.

Expected hourly output was derived for all four solar systems, and scaled up to a moderate penetration of the technology in Utah. Similarly to the wind scenario, each was assumed to reach 880 MW by 2020, or 80 MW per year from 2011 to 2020.

The equivalent capacity factors and power output from the two solar PV scenarios are given in Table 6-8.

Table 6-8: Potential capacity factor of for solar PV and CSP scenarios and expected power output in simulation by year.

	Capacity Factor	Power output in 2010 (GWh)	Power output in 2015 (GWh)	Power output in 2020 (GWh)
Flat Plate PV	17.8%	166	999	1,374
Single Axis Track PV	23.8%	178	1,071	1,831
Parabolic Trough CSP, wet and dry cooled[133]	34.5%	243	1,455	2,668

6.3.3. Geothermal

The Basin and Range formation of central and western Utah is considered a rich geothermal resource. Utah has two geothermal power plants, the Blundell Power Station and Thermo Hot Springs, both in Beaver County. Combined, the state had 50 MW of nameplate geothermal capacity online in 2008.[134]

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[132] Solar Advisor Model. https://www.nrel.gov/analysis/sam/

[133] Dry cooled systems do not have exactly the same power output characteristics as wet cooled systems. Dry cooled plants are de-rated in warmer weather because there is smaller temperature gradient between the steam and ambient air temperatures. These dynamics and differences are not captured in this analysis.

[134] Geothermal Power Plants in Utah, Table 5.5. Utah Geological Survey. Available online at http://geology.utah.gov/emp/energydata/statistics/electricity5.0/pdf/T5.5.pdf

In this study, there is a single geothermal scenario. The scenario assumes that a geothermal plant has a constant output of its full capacity. Geothermal plants are typically not used to meet peaking loads and are taken offline only for maintenance purposes. Therefore, to estimate the impact of geothermal energy on displaced generation and emissions, the proxy plant runs at capacity at all hours. The geothermal scenario models 440 MW of capacity by 2020.

Binary geothermal operations can consume significant amounts of water. In a binary system, relatively low-temperature (100-300ºF) geothermal fluids are used to evaporate low-boiling point fluids through a steam power cycle. Cooling water is used to condense the steam and complete the cycle. We estimate 1,400 gallons per MWh of fresh water are required in wet- cooled binary plants. [135] While there are several different models of geothermal facility currently in use and proposed for Utah today, it is expected that over the next decades, the most economic geothermal plants may be wet cooled binary. For internal consistency, we assume a single plant type in this analysis.

6.3.4. Renewable Energy Results

The generation expected in the renewable energy scenarios is shown in Table 6-9. Coal generation is displaced moderately in some of the scenarios, but gas generation decreases far more substantially. The largest reductions of coal fired generation, excluding the replacement scenarios, are in the geothermal scenario.

Table 6-9: Fossil generation (GWh) in Utah at the end of the study period (2020-2021)

	Fossil Generation in Utah, GWh		
2007-2008	**Coal**	**Gas**	**Total**
Reference Case	38,966	8,202	47,169
2020-2021			
Baseline	39,494	14,854	54,347
EE (SWEEP)	39,565	11,225	50,790
EE (2% per yr)	39,511	8,998	48,509
EE (3% per year)	38,459	7,562	46,021
Wind (Porcupine)	38,745	12,816	51,561
Wind (TAD North)	38,283	12,840	51,123
Wind (Medicine Bow)	38,425	12,412	50,837
Solar (Flat Plate PV)	39,115	13,825	52,940
Solar (One-Axis Track)	38,960	13,584	52,544
Solar (CSP Trough, Wet Cooled)	39,320	12,718	52,039
Solar (CSP Trough, Dry Cooled)	39,320	12,718	52,039
Geothermal	38,170	12,112	50,283
Replace Coal w/ EE and Gas	27,456	20,796	48,252
Replace Coal w/ EE and RE	27,273	15,522	42,796

Table 6-10 lists the externality costs of the various scenarios, as well as the baseline.

[135] US Department of Energy. December, 2006. Energy Demands on Water Resources: Report to Congress on the Interdependency of Energy and Water.Table B-1

Table 6-10: Externality costs for renewable energy scenarios at end of study period (2020-2021). Externality cost of mortality, morbidity, and water, in millions of 2008 dollars per year. In health valuation, bold values are totals, values in parentheses are Utah only.

2020-2021	Health Costs and Valuation, Million 2008$ per year All (in Utah)				Externality Cost of Water (Low - High)	Total Externality Cost (Low - High)
	Mortality		Morbidity			
Baseline	**$2,337**	($339)	**$41**	($21)	**$40 - $401**	**$2,418 - $2,779**
Wind (Porcupine)	**$2,285**	($327)	**$40**	($20)	**$39 - $386**	**$2,364 - $2,711**
Wind (TAD North)	**$2,271**	($325)	**$40**	($20)	**$38 - $383**	**$2,349 - $2,694**
Wind (Medicine Bow)	**$2,270**	($324)	**$40**	($20)	**$38 - $383**	**$2,349 - $2,693**
Solar (Flat Plate PV)	**$2,310**	($332)	**$41**	($20)	**$39 - $393**	**$2,390 - $2,744**
Solar (One-Axis Track)	**$2,299**	($330)	**$41**	($20)	**$39 - $391**	**$2,379 - $2,731**
Solar (CSP Trough, Wet Cooled)	**$2,319**	($333)	**$41**	($21)	**$43 - $429**	**$2,403 - $2,789**
Solar (CSP Trough, Dry Cooled)	**$2,319**	($333)	**$41**	($21)	**$40 - $396**	**$2,400 - $2,757**
Geothermal	**$2,256**	($320)	**$40**	($20)	**$47 - $464**	**$2,343 - $2,760**

The efficacy of the renewable energy cases in health and water co-benefits is given in Table 6-11. Co-benefit efficacy is estimated as the avoided externality cost relative to the amount of conventional generation displaced by the technology. By this analysis, the wind built at the TAD North site, and a single-axis tracking PV system produce the most significant co-benefit on a per MWh basis. It should be noted that the geothermal scenario effectively reduces health impacts but these benefits are offset by relatively high water consumption. The wet cooled CSP and geothermal scenarios are disadvantaged in this analysis by their water requirements, which exceed the water savings achieved by displacing mostly natural gas-fired generation.[136]

Table 6-11: Value of co-benefit for renewable energy scenarios at end of study period (2020-2021). Co-benefits in avoided dollars per MWh of avoided generation. In health valuation, bold values are totals, values in parentheses are Utah only.

2020-2021	Health Co-Benefits, 2008$ per MWh All (in Utah)				Avoided Cost of Water (Low - High)	Total Co-Benefit (Low - High)
	Mortality		Morbidity			
Wind (Porcupine)	**$18.6**	($4.5)	**$0.4**	$0.2	**$0.5 - $5.5**	**$19.5 - $24.4**
Wind (TAD North)	**$20.4**	($4.5)	**$0.5**	$0.2	**$0.6 - $5.5**	**$21.4 - $26.3**
Wind (Medicine Bow)	**$18.9**	($4.4)	**$0.4**	$0.2	**$0.5 - $5.2**	**$19.8 - $24.5**
Solar (Flat Plate PV)	**$19.0**	($4.9)	**$0.4**	$0.2	**$0.6 - $5.5**	**$20.0 - $25.0**
Solar (One-Axis Track)	**$20.7**	($5.0)	**$0.4**	$0.2	**$0.5 - $5.5**	**$21.7 - $26.6**
Solar (CSP Trough, Wet Cooled)	**$7.7**	($2.6)	**$0.1**	$0.1	**-$12.0 - -$1.2**	**-$4.2 - $6.6**
Solar (CSP Trough, Dry Cooled)	**$7.7**	($2.6)	**$0.1**	$0.1	**$0.2 - $2.0**	**$8.0 - $9.8**
Geothermal	**$19.8**	($4.6)	**$0.4**	$0.2	**-$15.6 - -$1.6**	**$4.6 - $18.7**

[136] It should be recalled that the geothermal scenario represents a build-out of wet cooled binary geothermal facilities. Lower water-use geothermal facilities would result in a smaller water externality, and therefore a higher co-benefit.

6.4. Coupled Energy Efficiency and Plant Replacement

In the face of tightening air quality standards, impending federal carbon regulations, falling gas prices, and as interest in developing new renewable energy and energy efficiency resources grows, utilities may face increasing pressure to replace or retire inefficient or high emissions fossil generators. Two scenarios were designed to explore the externality benefit of replacing selected coal generators with renewable energy and energy efficiency. In the scenarios, approximately one third of generation is replaced by a combination of efficiency, renewable energy, and combined cycle gas generation.

The co-benefit values of the two replacement scenarios are measured differently than other scenarios in this analysis. Rather than estimate the efficacy of the scenarios against the total amount of fossil generation displaced by efficiency or renewable energy, these two scenarios are measured against the amount of coal generation replaced by efficiency, gas, and renewable energy. The reasoning behind this fundamentally different analysis mechanism is that simply replacing coal generation with gas on a one-for-one basis would inevitably result in reduced health and water externalities, but no fossil reduction. Therefore, the benefit of this replacement would appear artificially inflated.[137] Because the scenarios have a fundamentally different design, their final co-benefit is measured relative to the total amount of coal generation displaced or replaced.

In these scenarios, generators built prior to 1980 were taken offline in order of their first year in operation. The unit order coincided, largely with the NO_x and SO_2 emissions rate of the unit, where older units have higher emissions rates. Table 6-15 at the end of this section shows the unit ages, emissions rates, and scenario-year offline. The plant replacement scenario retires the Carbon units in 2012 and 2013, the Huntington units in 2014 and 2016, and the Hunter 1 unit in 2018. Load growth follows the 2% Energy Efficiency Scenario, reducing the requirement for new generation over time.

In both of the scenarios, the 2% efficiency per year primarily offsets requirements for new gas generation. In the gas-based replacement version, gas generation rises by 41% as coal plants are replaced or retired. In the renewable-based scenario, a plausible mix of new renewable generation is brought online to eventually meet 20% of Utah's demand by 2020.[138] This resource mix includes:

- 60 MW per year of wind from Medicine Bow, WY (660 MW by 2020)
- 35 MW per year of wind from the TAD North site (385 MW by 2020)
- 30 MW per year of dry cooled solar parabolic trough CSP from Cedar City (330 MW by 2020)

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[137] Co-benefits are measured as the avoided externality per MWh of avoided generation. If there are few or no MWh of fossil generation avoided, the denominator becomes small, and the apparent co-benefit becomes very large.

[138] This ramp rate is moderately faster than the renewable energy goal called for under Utah's Energy Resource and Carbon Emission Reduction Initiative (S.B. 202), March 2008. Note that this RE goal is relative to Utah's demand, not generation. As a state, Utah generates nearly twice as much as it demands, and so this target results in less than 10% of generation served by RE.

A significant amount of coal generation is reduced by replacing a select number of inefficient coal generators with a combination of moderately aggressive energy efficiency (2% per year) and either gas-fired generators or renewable energy (see Table 6-12 and Figure 6-5 and Figure 6-6). Overall, coal generation drops by 30% relative to today.

Table 6-12: Fossil generation (GWh) in Utah at the end of the study period (2020-2021)

	Fossil Generation in Utah, GWh		
2007-2008	**Coal**	**Gas**	**Total**
Reference Case	38,966	8,202	47,169
2020-2021			
Baseline	39,494	14,854	54,347
Replace Coal w/ EE and Gas	27,456	20,796	48,252
Replace Coal w/ EE and RE	27,273	15,522	42,796

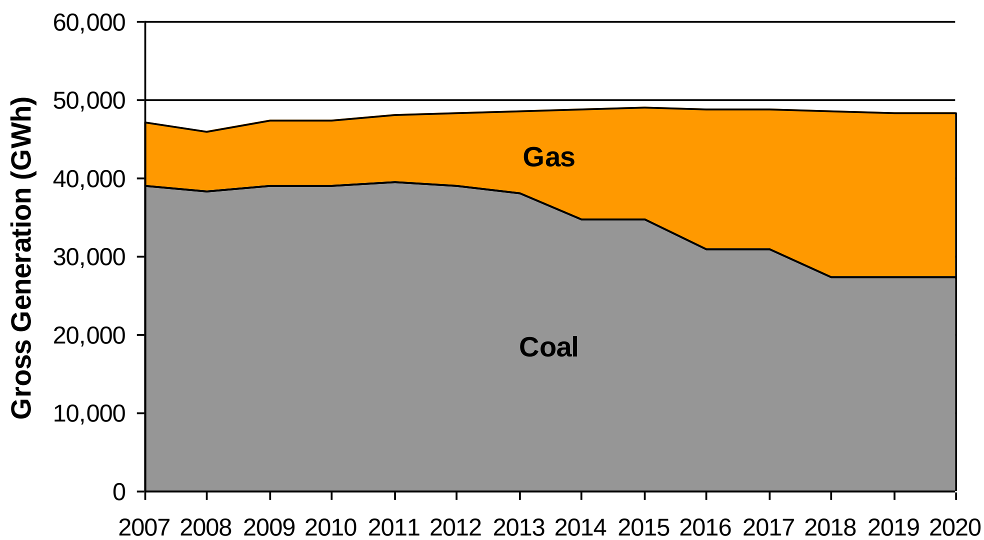

Figure 6-5: Annual gas and coal generation in the "Replace coal with EE and gas" scenario, in GWh.

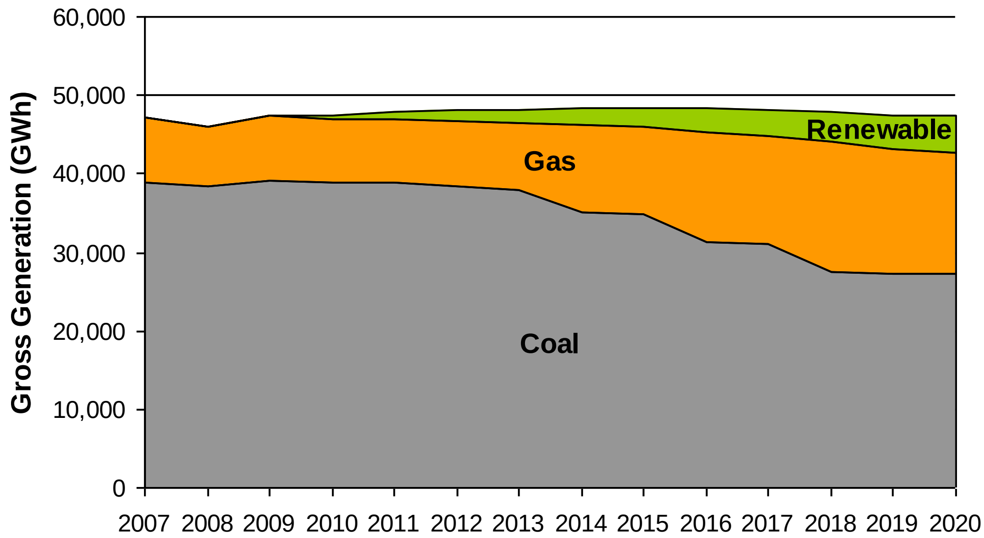

Figure 6-6: Annual gas, coal, and renewable generation in the "Replace coal with EE and RE" scenario, in GWh.

The externality costs of mortality, morbidity, and water drop significantly by replacing inefficient coal generators (see Table 6-13, below). The total externality cost drops from $2,418-2,779 million down to $1,553-1,853 million per year, an avoided cost between.$865 and $926 million each year.

Table 6-13: Externality costs for baseline and replacement scenario at end of study period (2020-2021). Externality cost of mortality, morbidity, and water, in millions of 2008 dollars per year. In health valuation, bold values are totals, values in parentheses are Utah only.

2020-2021	Health Costs and Valuation, Million 2008$ per year All (in Utah)				Externality Cost of Water (Low - High)	Total Externality Cost (Low - High)
	Mortality		Morbidity			
Baseline	**$2,337**	($339)	**$41**	($21)	**$40 - $401**	**$2,418 - $2,779**
Replace Coal w/ EE and Gas	**$1,527**	($250)	**$29**	($15)	**$30 - $297**	**$1,586 - $1,853**
Replace Coal w/ EE and RE	**$1,494**	($244)	**$29**	($15)	**$29 - $291**	**$1,553 - $1,815**

Co-benefits in the replacement scenarios cannot be judged against the same criteria as the other efficiency or renewable energy scenarios. In the other scenarios, EE or RE *passively* displaced existing generation, and therefore a proper metric was estimated as an avoided externality cost relative to avoided conventional generation. In the replacement scenarios, there would be significant benefits even if there was no net reduction in conventional generation. In this case, the benefits are realized because of active displacement of coal. Therefore, we estimate co-benefits relative to avoided MWh of coal generation.

The co-benefits of these scenarios range from $69 to $79 per MWh, depending on the estimated externality cost of water (see Table 6-14). Replacing coal with renewable energy reduces the amount of gas which needs to be brought online to support energy requirements (again, presuming no significant changes in dispatch), and therefore results in a slight improvement in health co-benefits. The water co-benefit of avoiding new gas is largely erased by the use of a water-intensive CSP operation in this scenario, yielding approximately the same water co-benefit for both scenarios.

Table 6-14: Value of co-benefit for replacement scenario at end of study period (2020-2021). Co-benefits in avoided dollars per MWh of avoided generation. In health valuation, bold values are totals, values in parentheses are Utah only.

	Health Co-Benefits, 2008$ per MWh All (in Utah)				Avoided Cost of Water (Low - High)	Total Co-Benefit (Low - High)
2020-2021	**Mortality**		**Morbidity**			
Replace Coal w/ EE and Gas	**$67.26**	($7.39)	**$1.00**	($0.48)	**$0.9 - $8.7**	**$69.1 - $76.9**
Replace Coal w/ EE and RE	**$68.94**	($7.79)	**$1.00**	($0.48)	**$0.9 - $9.0**	**$70.8 - $78.9**

Clearly, there are significant co-benefits to be realized from the replacement of existing coal generators alone. If we consider these co-benefits relative to the amount of fossil generation displaced by EE and RE, the values multiply into more than one hundred dollars saved per MWh of conventional generation avoided.

Table 6-15 below shows the characteristics of the coal units currently in operation in Utah.

Table 6-15: Capacity, year online, emissions rates, and heat rate of coal units in Utah. Emissions and heat rates for 2008 (January through December). Source: Derived from Clean Air Markets Division Dataset, EPA.

Plant (Replacement Date)	**Capacity (MW)**	**Year Online**	**NO_X** (lbs/MWh)	**SO_2** (lbs/MWh)	**CO_2** (t/MWh)	**Heat Rate** (btu/kWh)
Carbon 1 (2012)	75.0	1954	5.32	7.75	1.05	10,270
Carbon 2 (2013)	113.6	1957	5.11	7.94	1.10	10,725
Huntington 1 (2014)	498.0	1974	3.34	1.26	0.95	9,209
Huntington 2 (2016)	498.0	1977	2.08	0.54	0.97	9,451
Hunter 1 (2018)	488.3	1978	3.93	1.57	1.07	10,411
Hunter 2	488.3	1980	3.84	1.21	1.05	10,185
Hunter 3	495.6	1983	3.35	0.54	0.96	9,372
Bonanza 1	499.5	1986	3.60	0.50	1.08	10,506
Intermountain 1	820.0	1986	3.68	0.75	0.95	9,232
Intermountain 2	820.0	1987	3.47	0.74	0.94	9,184

6.5. Supplemental Fossil Additions

In all scenarios, excepting the 3% energy efficiency scenario, it was determined that additional fossil units may be needed to meet anticipated load growth. In each scenario, gas combined cycle (CC) and combustion turbine (CT) units were added as required with the simple criteria that the maximum open position each year could not exceed 300 MW. The fossil units are added simply to meet peak requirements in the dispatch model, and chosen as proxies of the types of plants that could be built in the future to meet new demand. Existing units are used to approximate statistical behavior of new units. The following scenario additions, shown in Table 6-16 are used to balance the model only, and do not represent a plan, optimized portfolio, or least cost solution. In most of the circumstances, the same cohort of units are added over time as in the baseline scenario to allow comparisons between emissions under BAU conditions and moderate penetrations of renewable energy.

Table 6-16: Additional units added to meet capacity requirements in each scenario. Values represent maximum reported gross generation for single or combined existing gas combined cycle (CC) or combustion turbine (CT) units in Utah.

	Baseline	EE (SWEEP)	EE (2% per yr)	EE (3% per year)	Wind (Cricket II)	Wind (Porcupine)	Wind (TAD North)	Wind (Medicine Bow)	Solar (Flat Plate PV)	Solar (One-Axis Track)	Solar (CSP Trough)	Solar (CSP Tower)	Geothermal	Replace Coal w/ EE and Gas	Replace Coal w/ EE and RE
2009															
2010															
2011	307 CC				307 CC	307 CC	307 CC	307 CC	307 CC	307 CC	307 CC	307 CC	307 CC		
2012															
2013	120 CT	120 CT	60 CT		120 CT	120 CT	120 CT	120 CT	120 CT	120 CT	120 CT	120 CT	120 CT		307 CC
2014	160 CT				160 CT	160 CT	160 CT	160 CT	160 CT	160 CT	160 CT	160 CT	160 CT	60 CT	308 CC
2015	289 CC	307 CC			289 CC	289 CC	289 CC	289 CC	289 CC	289 CC		289 CC	289 CC	60 CT	
2016														307 CC	584 CC
2017	295 CC				295 CC	295 CC	295 CC	295 CC	295 CC	295 CC	289 CC	295 CC	295 CC		
2018														308 CC	307 CC 60 CT
2019	120 CT	60 CT			120 CT	120 CT	120 CT	120 CT	120 CT	120 CT	120 CT	120 CT	120 CT		
2020	60 CT				60 CT	60 CT	60 CT	60 CT	60 CT	60 CT	60 CT	60 CT	60 CT		

7. Findings and Discussion

Utah is part of a highly interconnected Western grid, and is a net exporter of relatively inexpensive coal-based electricity. The externality costs of generation in Utah today and in the future are high: health and water externalities from Utah generators cost between $1.7 and $2.0 billion dollars today,[139] and could rise to between $2.4 and $2.8 billion per year by 2020. On a unit-energy basis, this externality cost ranges from $36 to $43 per MWh hour today, rising to $45 to $51 per MWh by 2020. These costs are comparable to the direct costs of generation (i.e. fuel, O&M, and capital recovery).

In general, we predict that reducing demand in Utah without the participation of neighboring states does not substantially benefit air quality or water availability in Utah. There are undoubtedly substantial financial and environmental benefits to both energy efficiency (EE) and renewable energy (RE), including reduced requirements for fossil fuels, reduced emissions of criteria and greenhouse gasses, and financial benefits to ratepayers. However, our results indicate that, because of Utah's position as a net exporter of coal-fired energy, reducing demand in the state will not substantially lower health risks or water consumption in Utah. Indeed, it is possible that reduced energy consumption in the state will instead result in larger exports of baseload coal-fired energy: a scenario that would likely result in a benefit for inexpensive power out-of-state, yet a high social cost of externalities in Utah and downwind states. This dilemma can be resolved by:

1. internalizing externality costs into resource and transmission planning exercises, or even dispatch decisions;
2. proactively reducing electric sector emissions and water consumption in Utah;
3. working with neighboring states to cut regional energy consumption, thus reducing export requirements from Utah.

These strategies can help Utah effectively realize high co-benefits from EE and RE in the state.

The following sections discuss results from this research, including avoided generation and emissions from implementing EE and RE in Utah, the externality costs of the system today and in the future, and the co-benefit cost effectiveness of EE and RE on health and water. Two appendices discuss non-quantified co-benefits on natural gas prices and regional haze in Utah.

7.1.1. Avoided Generation

This study finds that when energy efficiency or renewable energy impinges on load, gas generators are displaced preferentially, almost to the exclusion of coal generators. This is a fairly realistic portrayal of an expected response to moderate penetrations of efficiency or new renewable energy: gas generators are more expensive and more

[139] The range of costs is due to the uncertainty in the externality cost of water used in this study.

flexible then coal-fired generators and thus are more likely to respond to intermittent renewable generation. In a dispatch modeling exercise focused on the Western grid, researchers at the National Renewable Energy Laboratories (NREL) found that solar photovoltaic technologies would have to supply more than 15% of energy before coal in the west would be displaced.[140] It is feasible that at higher penetrations, renewable resources such as wind would actually require greater amounts of gas to balance intermittency, and therefore displace coal. However, in this exercise, we find that reducing generation requirements targets in Utah reduces gas generation, a finding with important implications for emissions, externalities, and eventually, the co-benefits of energy efficiency and renewable energy.

A second notable feature of this work is that our modeled penetrations of renewable energy and energy efficiency primarily displace new resources, rather than existing resources. According to estimates provided by PacifiCorp in 2008, load is expected to grow by an average of 2.15% per year between 2010 and 2018.[141] At this rate of growth and if Utah expects to continue exporting baseload coal-fired power, new resources would be required over the study period. This study assumes, from an emissions conservative standpoint, that new conventional resources would be fired by natural gas. Thus, new renewable energy would displace primarily new gas power. Even if load growth is significantly attenuated, EE and RE still primarily reduce gas-fired generation.

Table 7-1: Generation and avoided generation (GWh), by scenario.

	Generation (GWh)			Avoided Generation (GWh)		
2007-2008	**Coal**	**Gas**	**Total**	**Coal**	**Gas**	**Total**
Reference Case	38,966	8,202	47,169			
2020-2021						
Baseline	39,494	14,854	54,347			
			Energy Efficiency Scenarios			
EE (SWEEP)	39,565	11,225	50,790	-71	3,628	3,557
EE (2% per yr)	39,511	8,998	48,509	-17	5,855	5,838
EE (3% per year)	38,459	7,562	46,021	1,035	7,292	8,327
			Renewable Scenarios			
Wind (Porcupine)	38,745	12,816	51,561	749	2,038	2,786
Wind (TAD North)	38,283	12,840	51,123	1,211	2,014	3,225
Wind (Medicine Bow)	38,425	12,412	50,837	1,068	2,442	3,510
Solar (Flat Plate PV)	39,115	13,825	52,940	379	1,028	1,407
Solar (One-Axis Track)	38,960	13,584	52,544	533	1,270	1,803
Solar (CSP Trough, Wet Cooled)	39,320	12,718	52,039	173	2,135	2,309
Solar (CSP Trough, Dry Cooled)	39,320	12,718	52,039	173	2,135	2,309
Geothermal	38,170	12,112	50,283	1,323	2,741	4,065
			Replacement Scenarios			
Replace Coal w/ EE and Gas	27,456	20,796	48,252	12,038	-5,942	6,096
Replace Coal w/ EE and RE	27,273	15,522	42,796	12,220	-669	11,552

140 Denholm, P. R.M. Margolis, J.M. Milford. 2009. Quantifiying Avoided Fuel Use and Emissions from Solar Photovoltaic Generation in the Western United States. *Environmental Science and Technology*. **43**(1):226-231

141 Estimates provided by PacifiCorp may not reflect the subsequent economic downturn.

Table 7-1 shows changes in coal generation and gas generation from the reference period (2007-2008) through the end of the analysis period (2020-2021) for both the baseline and EE and RE cases. It can be seen that, with the exception of the two replacement scenarios, coal generation remains essentially unchanged and gas generation increases. The second set of columns in Table 7-1 and the diagram in Figure 7-1 show the avoided generation of gas and coal, or the difference between the given scenario and the baseline case.

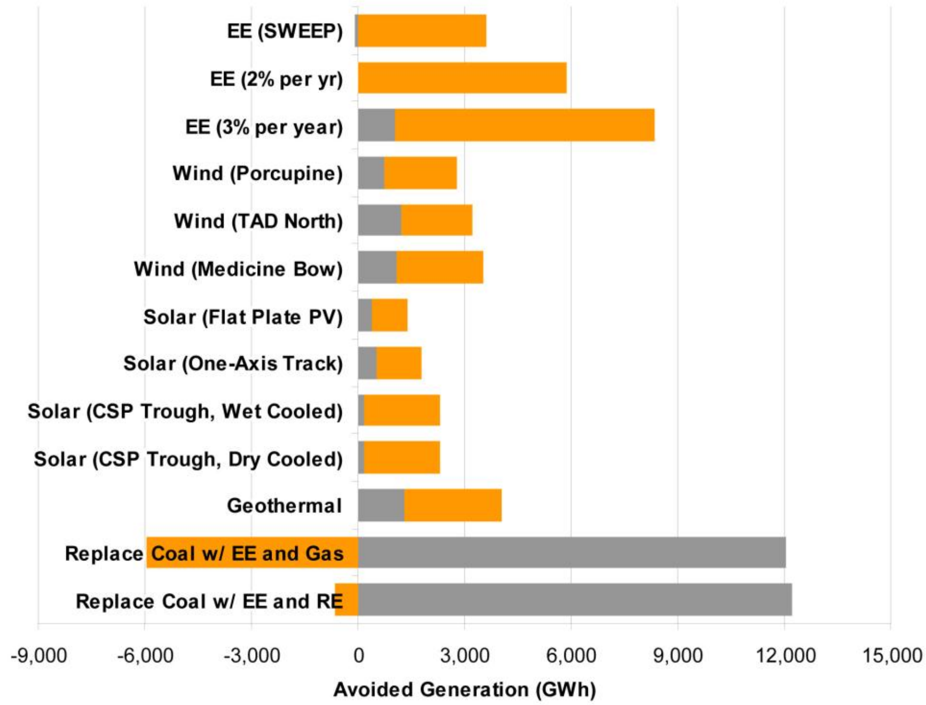

Figure 7-1: Avoided annual fossil generation (GWh) in each scenario by 2020. Gray bars are generation from coal, orange bars represent generation from gas. Negative avoided generation indicates increased utilization of gas in replacement scenario.

In all of the cases, new EE and RE primarily displace natural gas-fired generation. The impact of displacing only new and relatively efficient gas units is that modest penetrations of alternative energy resources yield onlymodest co-benefits in Utah. Gas-fired generators have relatively low emissions profiles and low water use relative to coal-fired generators; therefore, these programs only avoid a small fraction of the overall externalities imposed on society by Utah's generation fleet. In this study, only the replacement scenarios significantly reduce coal generation.

7.1.2. Physical Externalities and Avoided Externalities

In the reference case, fossil generation in Utah today results in an estimated 202 premature deaths per year. Damages from generators in Utah are experienced both in Utah and in downwind states. In this analysis, we find that over 86% of premature deaths occur in downwind states. In Table 7-2, below, we show morbidity and mortality across all impacted areas, followed by the number of deaths or sicknesses experienced by Utah's residents (in parentheses).

Table 7-2: Physical externalities from conventional generation

	Health Externalities, All (in Utah)								**Water Use** Acre Feet per Year
2007-2008	Statistical Deaths per Year		Cardiovascular Hospital Admissions per Year		Respiratory Hospital Admissions per Year		Emergency Room Visits per Year		
Reference Case	**202**	(28)	**21**	(2)	**154**	(70)	**175**	(72)	**73,800**
2020-2021									
	Baseline Scenario								
Baseline Load Growth	**279**	(41)	**32**	(3)	**194**	(90)	**225**	(93)	**77,400**
	Energy Efficiency Scenarios								
EE (SWEEP)	**277**	(40)	**31**	(3)	**193**	(90)	**224**	(92)	**75,900**
EE (2% per yr)	**274**	(39)	**31**	(3)	**192**	(89)	**223**	(92)	**75,800**
EE (3% per year)	**267**	(38)	**30**	(3)	**186**	(86)	**216**	(89)	**72,400**
	Renewable Scenarios								
Wind (Porcupine)	**273**	(39)	**31**	(3)	**189**	(88)	**220**	(90)	**74,400**
Wind (TAD North)	**271**	(39)	**31**	(3)	**187**	(87)	**218**	(89)	**74,000**
Wind (Medicine Bow)	**271**	(39)	**31**	(3)	**187**	(87)	**218**	(89)	**73,900**
Solar (Flat Plate PV)	**276**	(40)	**31**	(3)	**191**	(89)	**222**	(91)	**75,900**
Solar (One-Axis Track)	**275**	(39)	**31**	(3)	**190**	(88)	**221**	(91)	**75,500**
Solar (CSP Trough, Wet Cooled)	**277**	(40)	**31**	(3)	**192**	(89)	**224**	(92)	**82,700**
Solar (CSP Trough, Dry Cooled)	**277**	(40)	**31**	(3)	**192**	(89)	**224**	(92)	**76,500**
Geothermal	**269**	(38)	**31**	(3)	**186**	(86)	**217**	(89)	**89,600**
	Replacement Scenarios								
Replace Coal w/ EE and Gas	**182**	(30)	**20**	(2)	**137**	(65)	**157**	(67)	**57,300**
Replace Coal w/ EE and RE	**178**	(29)	**20**	(2)	**136**	(65)	**155**	(67)	**56,200**

Table 7-2 shows major categories of physical externalities, including health (mortality and morbidity) and water consumption. In the health externalities, columns are paired, with the first sets of values indicating total externalities, and the second sets of columns (in parenthesis) indicating the externalities estimated to occur within Utah's borders. On a business-as-usual trajectory, even if all new resources are relatively low-emissions gas fired generators, the model predicts nearly 280 premature deaths per year by 2020 (with 41 of these deaths, or 15% occurring in-state). In all of the non-replacement scenarios, the mortality rate increases with rising population. By replacing the most inefficient coal generators with energy efficiency and gas, the total mortality rate drops by 2020 to 182 premature deaths per year. All of the energy efficiency and renewable energy scenarios result in slightly decreased mortality rates relative to the baseline.

Morbidity statistics track similarly to mortality in the baseline scenario: respiratory disease hospitalizations rise by 25%, while cardiovascular hospital admissions rise by 50% from 2007 to 2020. Similar to mortality, only the replacement scenario results in significantly lower morbidity by 2020 relative to 2008.

Finally, we estimate that fossil generators in Utah consume approximately 73,800 acre feet of water for boilers and cooling purposes today; a majority of this consumption is by coal generators (93%). With increasing load growth and additional gas capacity, consumption rises to 77,400 acre feet per year by 2020 (91% coal). For the most part, renewable energy and energy efficiency projects displace low-water use gas generation. In most of the EE and RE scenarios, water consumption does not fall significantly from the baseline, and in the wet-cooled concentrating solar project (CSP) and the geothermal scenario, water consumption rises relative to the baseline scenario. When select coal generators are retired, consumption drops 25% to 56,200 - 57,300 acre feet, a savings of over 20,000 acre feet.

We consider co-benefits on a cost-efficacy basis, i.e. avoided externalities relative to the fossil energy avoided by new EE and RE programs. The scenarios in this research do not all displace the same amount of generation; thus to judge the efficacy of a particular technology on reducing externalities, we estimate reductions relative to displaced energy. It is useful to examine the avoided physical externalities (mortality, morbidity, and water use) by how much fossil generation (both gas and coal) is avoided.

Table 7-3: Avoided physical externalities per unit of energy for scenarios at end of study period (2020-2021). Health impacts in avoided externalities per avoided TWh of generation and avoided water use per avoided MWh of generation. In health valuation, bold values are totals, values in parentheses are Utah only.

2020-2021	**Health Co-Benefits, All** (in Utah) Deaths, Hospital Admissions, & ER Visits per Avoided TWh								**Avoided Water Use**
	Avoided Statistical Deaths per Year		Avoided Cardiovascular Hospital Adm / Year		Avoided Respiratory Hospital Adm / Year		Avoided ER Visits / Year		Gallons per Avoided MWh
	<u>Energy Efficiency Scenarios</u>								
EE (SWEEP)	**0.7**	(0.2)	**0.1**	(0.0)	**0.3**	(0.1)	**0.3**	(0.1)	**135**
EE (2% per yr)	**0.9**	(0.2)	**0.1**	(0.0)	**0.3**	(0.1)	**0.5**	(0.2)	**90**
EE (3% per year)	**1.5**	(0.3)	**0.2**	(0.0)	**0.9**	(0.4)	**1.1**	(0.5)	**195**
	<u>Renewable Scenarios</u>								
Wind (Porcupine)	**2.2**	(0.5)	**0.2**	(0.0)	**1.7**	(0.9)	**2.0**	(0.9)	**343**
Wind (TAD North)	**2.4**	(0.5)	**0.3**	(0.0)	**2.1**	(1.1)	**2.4**	(1.1)	**346**
Wind (Medicine Bow)	**2.3**	(0.5)	**0.2**	(0.0)	**1.8**	(0.9)	**2.1**	(0.9)	**325**
Solar (Flat Plate PV)	**2.3**	(0.6)	**0.2**	(0.0)	**1.9**	(0.9)	**2.1**	(1.0)	**349**
Solar (One-Axis Track)	**2.5**	(0.6)	**0.3**	(0.1)	**2.0**	(1.0)	**2.2**	(1.0)	**344**
Solar (CSP Trough, Wet Cooled)	**0.9**	(0.3)	**0.1**	(0.0)	**0.6**	(0.3)	**0.7**	(0.4)	**-755**
Solar (CSP Trough, Dry Cooled)	**0.9**	(0.3)	**0.1**	(0.0)	**0.6**	(0.3)	**0.7**	(0.4)	**124**
Geothermal	**2.4**	(0.6)	**0.3**	(0.0)	**1.9**	(1.0)	**2.2**	(1.0)	**-981**
	<u>Replacement Scenarios*</u>								
Replace Coal w/ EE and Gas	**8.0**	(0.9)	**0.9**	(0.1)	**4.7**	(2.1)	**5.7**	(2.1)	**545**
Replace Coal w/ EE and RE	**8.2**	(0.9)	**1.0**	(0.1)	**4.8**	(2.1)	**5.7**	(2.1)	**565**

*The replacement scenarios estimate co-benefits against is avoided coal generation. These values are not directly comparable to the other scenarios

Physical co-benefits are shown in Table 7-3. Health co-benefits are shown relative to avoided TWh (one million MWh) of fossil energy.[142] Water co-benefits are displayed relative to each avoided MWh of energy. The energy efficiency scenarios save on the order of one to 1.5 statistical lives per TWh of avoided generation, while the renewable energy scenarios avoid from one to two and half statistical lives per TWh of avoided generation. The energy efficiency scenarios primarily reduce the need for gas generation, and so there is very little water avoided on a per MWh basis. Only the most aggressive efficiency scenario impacts coal generation, thus saving more water per year on a MWh basis.

The replacement scenarios are specifically designed to understand the net impact of replacing coal-fired generation, and are not strictly "displacement" scenarios. Therefore, the estimate of co-benefits is gauged relative to the total amount of coal generation removed or displaced in the study year, rather than the total amount of conventional generation displaced. Nonetheless, these two scenarios have significant social benefits in Utah and in downwind states. By 2020, the replacement scenarios are estimated to avoid approximately 100 statistical deaths each year, 30% of which are in Utah. For each TWh of coal generation avoided, these scenarios avert approximately 8 deaths. These scenarios also reduce the total amount of water that is required for electrical generation, saving between 545 and 565 gallons per MWh of coal generation avoided.

7.1.3. Externality Costs and Co-Benefits

Mortality from fossil generation in Utah today is valued at more than $1.6 billion, of which $222 million (13%) is realized in Utah (see Table 7-4). Adding additional gas generators, increasing the utilization of existing coal units, and increasing the population results in a cost over $2.3 billion from premature deaths, of which a slightly higher fraction (14.5%) is in Utah. The increased fraction in Utah is due to particulates from gas closer to existing population centers. Mortality costs are moderately lower for the energy efficiency and renewable energy scenarios, with aggressive energy efficiency (3%) resulting in the lowest cost without removing existing generators. As seen above, replacing inefficient coal units results in the greatest reduction in health externality costs, 5.5% below today's costs.

[142] For comparative purposes, a 400 MW power plant operating at an 85% capacity factor would produce about three TWh per year.

Table 7-4: Externality costs for scenarios relative to reference (2007-2008) and at end of study period (2020-2021). Externality cost of mortality, morbidity, and water, in millions of 2008 dollars per year. In health valuation, bold values are totals, values in parentheses are Utah only.

2007-2008	Health Costs and Valuation, Million 2008$ per year **All** (in Utah) Mortality		Morbidity		Externality Cost of Water (Low - High)	Total Externality Cost (Low - High)
Reference Case	**$1,612**	($222)	**$32**	($16)	**$38 - $383**	**$1,683 - $2,027**
2020-2021						
			Baseline Scenario			
Baseline	**$2,337**	($339)	**$41**	($21)	**$40 - $401**	**$2,418 - $2,779**
			Efficiency Scenarios			
EE (SWEEP)	**$2,317**	($334)	**$41**	($21)	**$39 - $393**	**$2,397 - $2,751**
EE (2% per yr)	**$2,291**	($329)	**$41**	($21)	**$39 - $393**	**$2,372 - $2,725**
EE (3% per year)	**$2,234**	($316)	**$40**	($20)	**$38 - $375**	**$2,312 - $2,649**
			Renewable Scenarios			
Wind (Porcupine)	**$2,285**	($327)	**$40**	($20)	**$39 - $386**	**$2,364 - $2,711**
Wind (TAD North)	**$2,271**	($325)	**$40**	($20)	**$38 - $383**	**$2,349 - $2,694**
Wind (Medicine Bow)	**$2,270**	($324)	**$40**	($20)	**$38 - $383**	**$2,349 - $2,693**
Solar (Flat Plate PV)	**$2,310**	($332)	**$41**	($20)	**$39 - $393**	**$2,390 - $2,744**
Solar (One-Axis Track)	**$2,299**	($330)	**$41**	($20)	**$39 - $391**	**$2,379 - $2,731**
Solar (CSP Trough, Wet Cooled)	**$2,319**	($333)	**$41**	($21)	**$43 - $429**	**$2,403 - $2,789**
Solar (CSP Trough, Dry Cooled)	**$2,319**	($333)	**$41**	($21)	**$40 - $396**	**$2,400 - $2,757**
Geothermal	**$2,256**	($320)	**$40**	($20)	**$47 - $464**	**$2,343 - $2,760**
			Replacement Scenarios			
Replace Coal w/ EE and Gas	**$1,527**	($250)	**$29**	($15)	**$30 - $297**	**$1,586 - $1,853**
Replace Coal w/ EE and RE	**$1,494**	($244)	**$29**	($15)	**$29 - $291**	**$1,553 - $1,815**

On a relative scale, morbidity costs are significantly lower, but this is primarily a function of how lost lives are valued versus a range of sicknesses, including cardiovascular and respiratory illnesses. Today's cost is about $32 million, with half of the cost experienced in Utah's borders ($16 million). These morbidity costs reflect healthcare costs for the fraction of health problems attributed to particulates, ozone, and other power plant pollutants.

The externality cost of water is predominated by water use from coal generators; increasing demand by 2020 does entail a higher water cost, but because this new load is primarily met with gas-fired generation, the additional water cost only rises by 5% in the baseline case. The range of externality costs of water extends from $38 million at the low end to $383 million at the upper end, depending on how water is valued (as described in Section 5.3). These costs could rise by five percent in the baseline case, or anywhere from a tenth of a percent (in the Medicine Bow wind case) to twelve percent (the water intensive concentrating solar trough case) above today's costs, according to the scenarios constructed for this study. Conversely, retiring water intensive coal-fired power plants and replacing them with either gas-fired generation or renewable energy reduces the social cost of water by 22-24% from today's costs.

Combined, health and water externalities from Utah generators cost between $1.7 and $2.0 billion today, and could rise to $2.4 to $2.8 billion by 2020. On a per unit energy basis, externalities cost society $36-$43/MWh generated today, expenses on par with the cost of conventional generation, a conclusion shared by a recent report of the National Academy of Sciences. [143] Electricity generated in Utah to serve both Utah and Pacific states results in damages to both Utahns and downwind populations, primarily to the east of Utah.

Without mitigation, in the future Utah and the West's expanding population will put more people at risk for exposure to fine particulates and ozone from conventional generation. In the baseline scenario, externality costs rise to $44-$51/MWh. These costs, internalized into the cost of generation, would have deep implications as to how new resources are selected or dispatched.

While externalities from electric fired generation are very high, the co-benefits that can be realized by passively displacing existing generation with new energy efficiency programs or renewable energy programs are fairly modest.[144] In this study, the most effective technologies for reducing health and water impacts will yield a higher cost savings per MWh. In Table 7-5, co-benefits are estimated for mortality and morbidity (both in total, and in Utah alone), and water consumption by power plants. Figure 7-2 portrays this information graphically,

[143] National Academy of Sciences. Hidden Costs of Energy: *Unpriced Consequences of Energy Production and Use.* Committee on Health, Environmental, and Other External Costs and Benefits of Energy Production and Consumption; National Research Council. National Academies Press, 2009.

[144] It should be noted that co-benefits are defined in this paper as the monetized social externalities of generation avoided for every MWh of avoided generation.

Table 7-5: Value of co-benefit for scenarios at end of study period (2020-2021) per MWh. Co-benefits in avoided dollars per MWh of avoided generation. In health valuation, bold values are totals, values in parentheses are Utah only.

2020-2021	Health Co-Benefits, 2008$ per MWh **All** (in Utah) Mortality		Morbidity		Avoided Cost of Water (Low - High)	Total Co-Benefit (Low - High)
			Efficiency Scenarios			
EE (SWEEP)	**$5.6**	($1.5)	**$0.1**	$0.0	**$0.2 - $2.1**	**$5.9 - $7.8**
EE (2% per yr)	**$7.8**	($1.7)	**$0.1**	$0.0	**$0.1 - $1.4**	**$8.0 - $9.3**
EE (3% per year)	**$12.3**	($2.8)	**$0.2**	$0.1	**$0.3 - $3.1**	**$12.8 - $15.6**
			Renewable Scenarios			
Wind (Porcupine)	**$18.6**	($4.5)	**$0.4**	$0.2	**$0.5 - $5.5**	**$19.5 - $24.4**
Wind (TAD North)	**$20.4**	($4.5)	**$0.5**	$0.2	**$0.6 - $5.5**	**$21.4 - $26.3**
Wind (Medicine Bow)	**$18.9**	($4.4)	**$0.4**	$0.2	**$0.5 - $5.2**	**$19.8 - $24.5**
Solar (Flat Plate PV)	**$19.0**	($4.9)	**$0.4**	$0.2	**$0.6 - $5.5**	**$20.0 - $25.0**
Solar (One-Axis Track)	**$20.7**	($5.0)	**$0.4**	$0.2	**$0.5 - $5.5**	**$21.7 - $26.6**
Solar (CSP Trough, Wet Cooled)	**$7.7**	($2.6)	**$0.1**	$0.1	**-$12.0 - -$1.2**	**-$4.2 - $6.6**
Solar (CSP Trough, Dry Cooled)	**$7.7**	($2.6)	**$0.1**	$0.1	**$0.2 - $2.0**	**$8.0 - $9.8**
Geothermal	**$19.8**	($4.6)	**$0.4**	$0.2	**-$15.6 - -$1.6**	**$4.6 - $18.7**
			Replacement Scenarios*			
Replace Coal w/ EE and Gas	**$67.26**	($7.39)	**$1.00**	($0.48)	**$0.9 - $8.7**	**$69.1 - $76.9**
Replace Coal w/ EE and RE	**$68.94**	($7.79)	**$1.00**	($0.48)	**$0.9 - $9.0**	**$70.8 - $78.9**

*The replacement scenarios estimate co-benefits against is avoided *coal* generation. These values are not directly comparable to the other scenarios

Moderate savings from energy efficiency (primarily reduced gas usage) save from $6-$16 per MWh in externality costs by 2020, with more aggressive EE displacing more coal generation and therefore yielding greater benefit. Amongst the renewable energy technologies, wind at the TAD north site and tracking solar PV in Cedar City offer the best opportunities to reduce the externality costs quantified in this analysis. The concentrating solar thermal projects show a lower net co-benefit (even a negative co-benefit, or a net cost) because of the high water demand from these units. Since the renewable energy projects primarily displace gas at moderate penetrations, any significant use of water (such as in solar boilers) is a net cost to society, unless these costs are internalized by renewable energy projects.

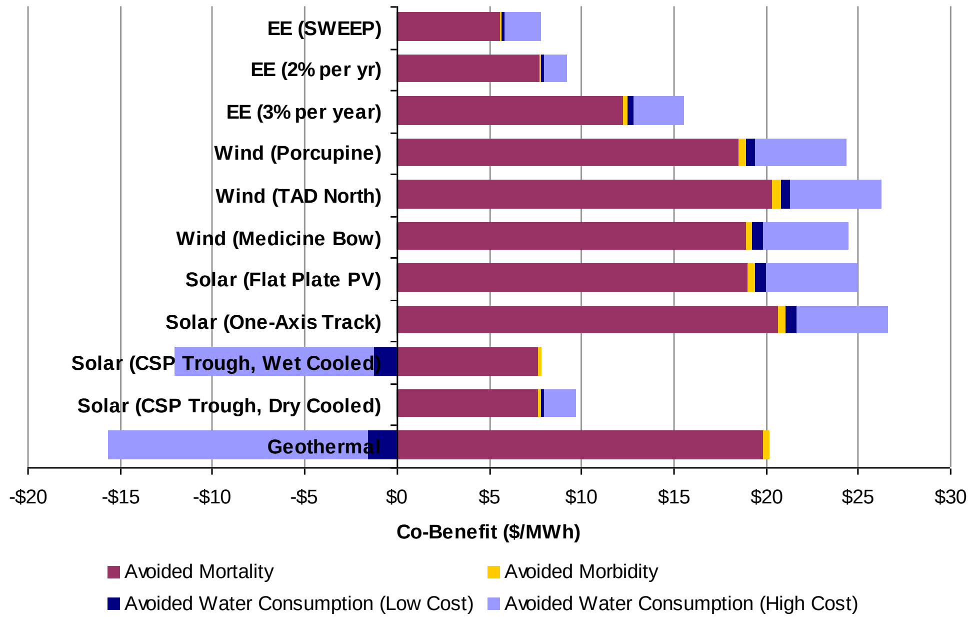

Figure 7-2: Value of co-benefits for energy efficiency and renewable energy scenarios in 2020, relative to baseline. Light blue bar represents savings (or cost) of avoided water use at a high externality cost of water. Dark blue bar represents the differential if the externality cost of water is low. Negative values of water co-benefits indicate that the energy alternative (i.e. concentrating solar power) is more water intensive than conventional generation.

As seen in Figure 7-2, the highest co-benefits are derived from avoiding premature deaths due to fine particulates and other air pollution. Avoided water use can result in large co-benefits as well, if the social value of water is priced at the margin (as discussed in Section 5.3) and if replacement technologies do not use more water than would otherwise be saved. In both the wet cooled CSP trough and geothermal scenarios, more water is consumed by the replacement energy than is saved by passive displacement. Using dry cooled technologies can mitigate this problem.

The societal benefits from replacing coal with natural gas or a mix of renewable energy are significant, but not directly comparable to the passive displacement by EE and RE alone. Again, the final two scenarios are measured against the amount of coal generation replaced or displaced. For each MWh of coal displaced by a combination of energy efficiency and gas or renewable energy in 2020, externalities are reduced by $69-$81. This large co-benefit exceeds the all-in cost of coal-fired generation in almost all circumstances.

7.2. Study Assumptions and Exclusions

It should be noted that these analyses have several key assumptions, and that changes from them may affect the results. The assumptions and the way results could change are described below.

7.2.1. Existing Transmission Constraints are Maintained

Dispatch decisions today are guided by variable resource costs, availability, reliability, and physical constraints. One significant constraint that determines which resources will be dispatched to meet load are transmission constraints.

Utah is a net exporter of energy, producing more electricity than it consumes. However, the amount of energy that can be transmitted out-of-state is limited by the capacity of the transmission lines to areas of demand (load centers). Currently, when demand out-of-state is high and there is little hydroelectric capacity available, coal generators in Utah operate nearly continuously. The exception to this is during off-peak hours in Utah. In these hours, Utah enters a unique position where it has more capacity than can be carried by transmission systems into the Northwest or California, and even some large coal generators are forced to back down slightly. An example of this dynamic can be seen in the time series in Figure 7-3.

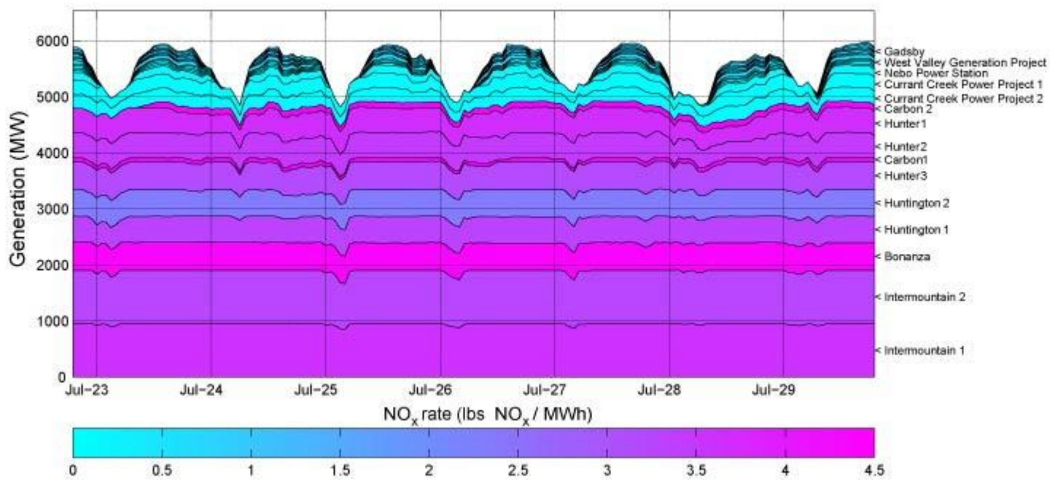

Figure 7-3: Generation in Utah from July 23, 2007 through July 29, 2007, showing few hours in which coal units (shades of pink and purple) back down during summer trough hours. Colors indicate NO_X emissions rate in lbs per MWh. Generators are ordered by capacity factor during week.

The model used here recognizes the hours in which generators change behavior due to the dispatch decisions described above, but the analysis does not model these decisions, it simply replicates choices made in the past. If transmission constraints were lifted or modified, dispatch decisions could change markedly throughout the West, and historical behavior might provide a poor analog for future decisions. If these constraints were lifted by building more transmission from or through Utah, there would be fewer hours where coal generators could not operate continuously. Barring changes in environmental regulations or other constraints, additional transmission would likely result most immediately in even higher capacity factors for baseload generators. The expected impact on the results of this analysis would be an increase in the externality cost, and fewer opportunities to displace the large externalities of coal except through direct replacement.

7.2.2. *Social Cost of Greenhouse Gas Emissions are Not Evaluated*

At the time that the Utah agencies developed this project, it was determined that potential or future carbon costs should not be addressed pending resolution of ongoing policy debates and/or actual federal legislation. As a result, this study was not scoped to estimate the externality cost of greenhouse gas (GHG) emissions. GHG, such as CO_2, accumulate in the atmosphere and trap solar radiation, leading to a warming of the atmosphere. A large body of research suggests that GHG emissions that are released today will lead to significant changes in the earth's climate, including warming at the poles, changes in precipitation patterns, sea level rise, and expansion of disease vectors.[145] Models and field experiments have shown that the changes that could result from global climate change would permanently alter or destroy ecosystems and economies, and displace numerous individuals.[146] These impacts have been shown to have a large economic impact on society.[147, 148] Since these costs are not currently internalized into the cost of emitting GHG, these costs can be considered an externality cost. In the United States, most anthropogenic (human-caused) emissions of GHG are from the combustion of fossil fuels,[149] and are in the form of CO_2. The externality cost of CO_2 emissions from power plants may, in the future, be partially internalized by climate legislation.[150] However, the un-internalized cost today and in the future could quickly exceed other costs estimated in this study.

Following findings in other studies, including the Integrated Panel on Climate Change,[145] the Stern Report,[147] a recent National Academy of Sciences report,[151] and recommendations on the avoided cost of energy sponsored by New England utilities, [152] we estimate a *social* cost of CO_2 at $80 per ton of CO_2 (2008$).[153] If this long-run marginal abatement cost were included formally in this study, the externality cost of

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[145] Contribution of Working Groups I, II and III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change. Core Writing Team, Pachauri, R.K. and Reisinger, A. (Eds.) IPCC, Geneva, Switzerland. pp 104

[146] Climate Change and Displacement. Forced Migration Review. Issue 31, October 2008. Refugee Studies Center. Available online: http://www.fmreview.org/FMRpdfs/FMR31/FMR31.pdf

[147] Stern Review: The Economics of Climate Change. 2006. Cambridge University Press. Available online: http://www.hm-treasury.gov.uk/stern_review_report.htm

[148] Ackerman, F. and E.A. Stanton. 2008. The Cost of Climate Change: What We'll Pay if Global Warming Continues Unchecked. Available online: http://www.nrdc.org/globalwarming/cost/cost.pdf

[149] US. EPA. 2009 US Greenhouse Gas Inventory Report. April 2009. Available online: http://www.epa.gov/climatechange/emissions/usinventoryreport.html

[150] If legislation puts a price on greenhouse gas emissions, the externality price would be the net difference between the social cost of greenhouse gas emissions and the market price of these emissions.

[151] National Academy of Sciences. Hidden Costs of Energy: *Unpriced Consequences of Energy Production and Use.* Committee on Health, Environmental, and Other External Costs and Benefits of Energy Production and Consumption; National Research Council. National Academies Press, 2009.

[152] Hornby, R., P. Chernick, C. Swanson, et al. 2009. Avoided Energy Supply Costs in New England. Prepared for the Avoided-Energy-Supply-Component (AESC) Study Group [New England Utilities]

[153] These externality costs are *not* the expected costs of compliance, but rather the damage costs of emissions. We anticipate that as carbon dioxide emissions are regulated in coming decades that an increasing portion of this $80 social cost will be "internalized" by regulation, with potentially far lower compliance or abatement costs. This internalization is not reflected in the long-run externality cost estimated here.

generation from Utah today would be nearly $3.4 billion, or $72 per MWh of conventional generation. Table 7-6 shows emissions from gas and coal in Utah today (in million short tons per year) and in each of the scenarios at the end of the analysis period. The fifth column shows the externality cost with a social cost of carbon at $80/tCO$_2$. Finally, the last two columns show the avoided CO_2 emissions (in million short tons per year) and the CO_2 co-benefit which would be realized on a per MWh basis for each of the scenarios.

Table 7-6: Emissions of carbon dioxide (million tons CO_2), externality cost (in millions), avoided emissions, and the CO_2 co-benefit for each scenario. The co-benefits for the replacement scenarios are relative to avoided coal generation.

	CO_2 (M Tons)			CO_2 Externality, Million $	Avoided CO_2	CO_2 Co-Benefit ($/MWh)
2007-2008	**Gas**	**Coal**	**Total**			
Reference Case	38.85	3.41	42.26	$3,381		
2020-2021						
Baseline	39.39	6.13	45.52	$3,642		
		Energy Efficiency Scenarios				
EE (SWEEP)	39.49	4.69	44.18	$3,535	1.34	$30.09
EE (2% per yr)	39.40	3.79	43.19	$3,455	2.33	$32.00
EE (3% per year)	38.36	3.12	41.48	$3,319	4.04	$38.79
		Renewable Scenarios				
Wind (Porcupine)	38.63	5.25	43.88	$3,510	1.64	$47.17
Wind (TAD North)	38.19	5.28	43.48	$3,478	2.04	$50.73
Wind (Medicine Bow)	38.38	5.09	43.47	$3,478	2.05	$46.74
Solar (Flat Plate PV)	39.00	5.68	44.68	$3,574	0.84	$47.96
Solar (One-Axis Track)	38.91	5.57	44.48	$3,559	1.04	$46.10
Solar (CSP Trough, Wet Cooled)	39.26	5.27	44.53	$3,563	0.99	$34.23
Solar (CSP Trough, Dry Cooled)	39.26	5.27	44.53	$3,563	0.99	$34.23
Geothermal	38.12	4.94	43.06	$3,445	2.46	$48.51
		Replacement Scenarios*				
Replace Coal w/ EE and Gas	27.34	8.43	35.76	$2,861	9.76	$64.84
Replace Coal w/ EE and RE	27.16	6.54	33.70	$2,696	11.82	$77.36

If a greenhouse gas externality cost is adopted, the price of CO_2 emissions quickly exceeds the cost of most conventional generation. Conversely, large co-benefits of $30-$51/MWh are realized for new energy efficiency and renewable energy programs from CO_2 avoidance alone. Not unexpectedly, replacing coal with energy efficiency and either gas generation or a mix of renewable energy and gas would yield significant co-benefits for each MWh of coal replaced. These costs and co-benefits are not estimated in the analysis of health and water co-benefits.

7.2.3. Additional Environmental Costs

In this study, internalized environmental costs are not estimated. New federal emissions rules, including the Clean Air Interstate Rule (CAIR) and regional haze reduction regulations (known as the Best Available Retrofit Technology ruling, or BART), may impose additional costs on fossil-fired generators, effectively internalizing a portion of the external costs of generation. In addition, mercury and other toxic reduction rulings (such as CAMR, the Clean Air Mercury Rule) could impart an additional environmental cost representing the internalization of a social externality. If new environmental costs are internalized into the variable cost of operation, the dispatch decisions in the region could change dramatically (including making coal units more expensive to run), thus changing the results of this analysis.

7.2.4. Utah Acts Alone

One of the most significant assumptions in this analysis is that Utah acts alone in implementing new renewable energy or energy efficiency programs. This study is scoped to determine the impact of implementing new EE and RE in Utah, or delivered to Utah. If other states participate in similar programs, the demand for conventional generation exported from Utah could fall, yielding social benefits to Utah and downwind states in excess of those estimated in this study. For example, changes in demand from neighboring states, and particularly in electricity importing states such as California, could have broad impacts on Utah's generators.

California is currently scoping a plan to reduce the state's carbon footprint.[154] In a recent study, the state determined that California demand is met in part by coal-fired plants in the Rocky Mountain West, and that two of Utah's plants are within the top five emitters contributing to California's energy.[155] Demand for energy from coal-fired plants that both serve California entities directly, such as the Intermountain Power Project, and indirectly by sales through the Western Interconnect may be reduced as California works to decrease demand, increase renewable energy, and decrease dependencies on high emissions plants in the west.

7.3. Policy Implications

The research presented in this project has a number of potential applications in informing Utah policy and planning processes. Externalities reflect social costs that are not accounted for in the market cost of a commodity. As such, the consideration of externalities in planning marks an opportunity to more fully account for the public good. Generation and the delivery of energy is commonly considered a pubic service, provided for the benefit of society. However, the current cost of energy to consumers masks an additional social cost of lost lives from air pollution, lost productivity and quality of life from medical conditions caused or exacerbated by emissions, and the opportunity cost of using scarce water resources for power generation rather than development, agriculture, or environmental needs.

The future of energy planning will require rigorous accounting of emissions and water consumption. Rules recently promulgated by and expected from the US EPA cover air emissions and water use, and the stringency and enforcement of these rules is only expected to become tighter. Locally, studies conducted for the California greenhouse

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[154] Climate Change Scoping Plan: a Framework for Change. December, 2008. California Air Resources Board. Available online at: http://www.arb.ca.gov/cc/scopingplan/document/adopted_scoping_plan.pdf

[155] Mandatory Greenhouse Gas Reporting: 2008 Reported Emissions. November, 2009. California Air Resources Board. Available online at: http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-reports.htm

gas reduction plan, A.B. 32, identify power plants in Utah as sources of imported emissions. As Utah prepares for a new energy paradigm, the social costs of generation and the benefits accrued from EE and RE should be an intrinsic part of the planning process. The following are several mechanisms in which externalities and co-benefits may be directly considered.

- **Integrated Resource Plan (IRP):** PacifiCorp's 2008 IRP was submitted to Utah and five other states in May 2009. Utah PSC Docket 90-2034-01 prescribes the standards required for IRPs, including the identification of current and future financial risks. The docket specifically requires externalities and environmental costs to be considered, and the IRP process in Utah allows externality costs to be recognized in the definition of "least cost" resources. New renewable energy and energy efficiency programs may be more effectively characterized not only through the avoided cost of energy, but through externalities avoided. A full accounting of the cost of power in resource plans might include downstream social costs, such as health impacts, water consumption and pollution, and risk of damages from greenhouse gas emissions, as well as upstream costs and benefits associated with the procurement of fuel and land use impacts.
- **State Implementation Plan (SIP):** Four metropolitan areas along the Wasatch Front were recommended by Utah for non-attainment designation under the EPA eight-hour ozone standard. EPA's final decision is due by March 2010. The Utah air quality agency must then develop requirements, for approval by EPA, that reduce emissions that cause or contribute to ozone non-attainment. Several of the scenarios analyzed for this report could be further evaluated (to improve precision to the level required for EPA approval) and included as revisions to Utah's SIP; this process, using similar tools, is moving forward in other states in cooperation with the EPA.
- **Evaluation of Utility DSM Programs:** As PacifiCorp develops new or revises existing demand side management (DSM) programs, regulators may choose to calculate the value of displaced externalities and factor that value into cost/benefit evaluations. This would tend to support the implementation of programs that would appear to be less effective on a strict direct cost basis.
- **Resource Acquisition Approvals:** At present, PacifiCorp is required to seek approval from the Public Service Commission for the building or purchase of "significant energy resources" over 100 MW capacity (300 MW for renewables). (UT Code 54-17). An understanding of the externality value (or costs) of different types of resources may be used as part of the evaluation of competing generation resource types.
- **Regional air quality, water quality and greenhouse gas planning processes:** Utah actively participates and/or observes several concurrent environmental planning processes. These include the Western Regional Air Partnership (WRAP), the Western Climate Initiative (WCI), the Western States Air Resources Council (WESTAR), and various water quality planning efforts. Reducing environmental impacts from the generation of electricity will require

cooperation from several states to ensure that similar policy measures are consistently implemented. This report suggests that if California or other net consuming states in the WECC region reduce electricity imports, the quantity of Utah's fossil-fuel generation could be markedly decreased, with a positive impact on health and water in the state and downwind regions.

- **Internalizing social costs:** Regulatory rules designed to reduce emissions or water consumption effectively compel the internalization of currently external costs. The EPA's Clean Air Visibility Rule (CAVR) and recently adopted Best Available Retrofit Technologies (BART) guidelines set a social cost for reduced visibility and other externalities. [156] The rules, which require a reduction in emissions at older, large facilities, are an explicit mechanism designed to internalize social externalities by mitigating visibility and health impacts.
- **Costs and benefits of renewable and/or energy efficiency standards:** In March of 2008, Utah enacted The Energy Resource and Carbon Emission Reduction Initiative (S.B. 202), which sets a goal of 20% renewable energy provided to Utah customers by 2025.[157] States that have enacted specific renewable energy or energy efficiency standards (RPS or EES) have adopted the practice of estimating air emissions reductions from RPS (i.e. Massachusetts[158]). In Utah, there is an opportunity to include externalities and co-benefits in the consideration of cost effectiveness in meeting Utah's 20% goal.
- **Social costs of generation:** The co-benefits from energy efficiency and renewable energy investments can be applied broadly to topics beyond the IRP and SIP processes. Improvements in public health and air quality benefit the state's budget, saving healthcare costs, increasing visibility in cities and at natural monuments, and ultimately providing important climate benefits for future generations. This document can assist the state in avoiding significant economic impacts by recognizing externality costs and adopting policies to benefit Utahns, both in the near and long-term.

While this report details several opportunities for Utah to pursue that could improve energy and environmental planning, we emphasize that this report is not a plan per se, nor does it reflect currently internalized costs or a range of additional externalities. Prior to the adoption of specific policies, the state should engage in additional research and evaluation. This report serves to point out opportunities for significant benefits in Utah.

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[156] U.S. EPA. June 2005. Regulatory Impact Analysis for the Final Clean Air Visibility Rule or the Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations. Office of Air and Radiation. EPA-452/R-05-004. Available online at: http://www.epa.gov/visibility/pdfs/bart_ria_2005_6_15.pdf

[157] Energy Resource and Carbon Emission Reduction Initiative (March, 2008). State of Utah, S.B. 202. Available online http://le.utah.gov/~2008/bills/sbillenr/sb0202.pdf

[158] Massachusetts Renewable Portfolio Standard: Cost Analysis Report. December, 2000. Available online: http://www.mass.gov/Eoeea/docs/doer/rps/fca.pdf

8. Appendix A: Wholesale Natural Gas Prices

8.1. Introduction and Purpose

Synapse was requested to discuss and/or quantify the second-order economic benefits of preventing summertime generation using natural gas peaking units. The focus of this section was subsequently defined as a qualitative and/or quantitative analysis of the impact of new energy efficiency and renewable energy programs on natural gas prices.[159] These impacts are referred to as demand-reduction-induced price effects, or DRIPE. DRIPE is defined as the change in wholesale prices experienced by all consumers due to reductions in procurement of a commodity (either electricity or natural gas) by some consumers. DRIPE describes the elasticity of a supply price, given a change in demand.

In general, we postulate that reduced demand for natural gas in Utah from energy efficiency or renewable energy programs will have little impact on Utah or regional natural gas prices. This section presents a qualitative discussion of the drivers of the impacts of demand reductions on natural gas prices and why these drivers may not be directly relevant to Utah or the gas-serving region to which it is connected (known as the Central Region[160]). Context is provided on Utah's natural gas production, consumption, transport, and delivery systems, in order to substantiate this argument. We did not produce an accompanying quantitative analysis due to the fact that we have projected little impact in natural gas prices due to demand reductions.

8.2. Background

Studies that quantify the DRIPE effect for natural gas have generally been conducted at a national level or for deregulated states. In general, these studies have focused on non-gas producing states and/or states that have relatively high natural gas consumption, both of which are highly prone to market price impacts and thus have potentially high DRIPE effects. One of the most comprehensive and recent analyses, a 2005 analysis by Ryan Wiser et al. of the Lawrence Berkeley National Laboratory,[161] stated that the twelve studies evaluated all analyzed renewable portfolio standard (RPS) and energy efficiency proposals at a national level.[162] In addition, there are five known state and regional level energy efficiency analyses, but all were conducted for large gas

[159] These second-order economic benefits are indirect, but tangible costs which are recognized in normal economic analyses and ratemaking. Shifts in the price of natural gas due to changes in supply or demand are not considered externalities, and therefore savings due to EE or RE programs would not strictly be considered co-benefits in the context of this study.

[160] The Central Region gas market includes CO, IA, KS, MO, MT, NE, ND, SD, UT, and WY. See http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/central.html

[161] Ryan Wiser, Mark Bolinger, and Matt St. Clair. Easing the Natural Gas Crisis: Reducing Natural Gas Prices through Increased Deployment of Renewable Energy and Energy Efficiency. Lawrence Berkeley National Laboratory. LBNL-56756. January 2005.

[162] This includes five studies by the EIA, six studies by the Union of Concerned Scientists (UCS) and one study by ACEEE.

consuming states.[163] A study by the American Council for an Energy Efficient Economy (ACEEE), conducted in 2003 and updated in 2005 modeled three scenarios including (a) the impact of a national energy efficiency and renewable energy policy on the lower 48 states, (b) the impact of a national energy efficiency policy on the lower 48 states and (c) the impact of a Midwest policy on Illinois, Indiana, Iowa, Michigan, Minnesota, Missouri, Ohio and Wisconsin. [164,165] For all the studies conducted, none were conducted in the previously defined Central Region, or for a gas producing region with low consumption and high exports. Most other studies of natural gas price elasticity have mainly been conducted on the impact of supply shocks on demand, rather than the impact of demand shocks on supply. Although each of these studies did find a DRIPE effect, none of these studies is directly applicable to Utah or to the Central Region.

8.3. Natural Gas DRIPE Drivers and Variables

The price of natural gas is driven by a number of factors: the scarcity of supply relative to demand, the ability of this supply to reach market, and the demand for the supply. DRIPE describes only the process that occurs when demand slackens. Significant DRIPE will occur only if the reduction in demand is proportionally large relative to supply, or if the demand reduction occurs in a constrained system. The following section describes five factors that can drive changes in the price of gas relative to a baseline, and details why these factors are unlikely to apply in Utah. These factors include:

- Scale and connectivity of the regional and national natural gas markets
- Proportion of supply subject to market prices,
- Scarcity of supply,
- Transport constraints, and
- High demand

8.3.1. Scale and connectivity of the regional and national natural gas markets

One of the most important drivers of DRIPE is the size of the market that establishes the natural gas prices. Local changes in demand more effectively influence regional markets as compared to national markets, where the demand reductions can appear comparably small and can be easily offset by other market changes. In natural gas markets, the

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[163] This includes 1 study by the Tellus Institute for Rhode Island and 5 scenarios in the American Council for an Energy Efficient Economy (ACEEE) study including one for California, Oregon, and Washington; another for the northeast and mid-Atlantic regions; a third for New York; and a fourth for Texas.

[164] R. Neal Elliott, Ph.d., P.E. and Anna Monis Shipley. Impacts of Energy Efficiency and Renewable Energy on Natural Gas Markets: Updated and Expanded Analysis. Report Number E052. American Council for an Enegy Efficient Economy (ACEEE). April 2005.

[165] R. Neal Elliott, Ph.d., P.E., Anna Monis Shipley, Steven Nadel, and Elizabeth Brown. National Gas Price Effects of Energy Efficiency and Renewable Energy Practices and Policies. Report Number E032. American Council for an Enegy Efficient Economy (ACEEE). December 2003.

impact of DRIPE can be ambiguous because natural gas is traded on regional, national, and some international markets.

Much of the research to date suggests that the natural gas market is a national market, rather than a regional market. This is demonstrated by the fact that annual average regional wellhead price trends and annual average Henry Hub price trends are relatively well correlated. As a result, changes in regional demand caused by localized energy efficiency and renewable efforts do not have a large impact on natural gas prices for that region. To confirm whether or not this is true for Utah, we compared trends of annual average Utah wellhead prices and annual average Henry Hub prices (Figure 8-1).

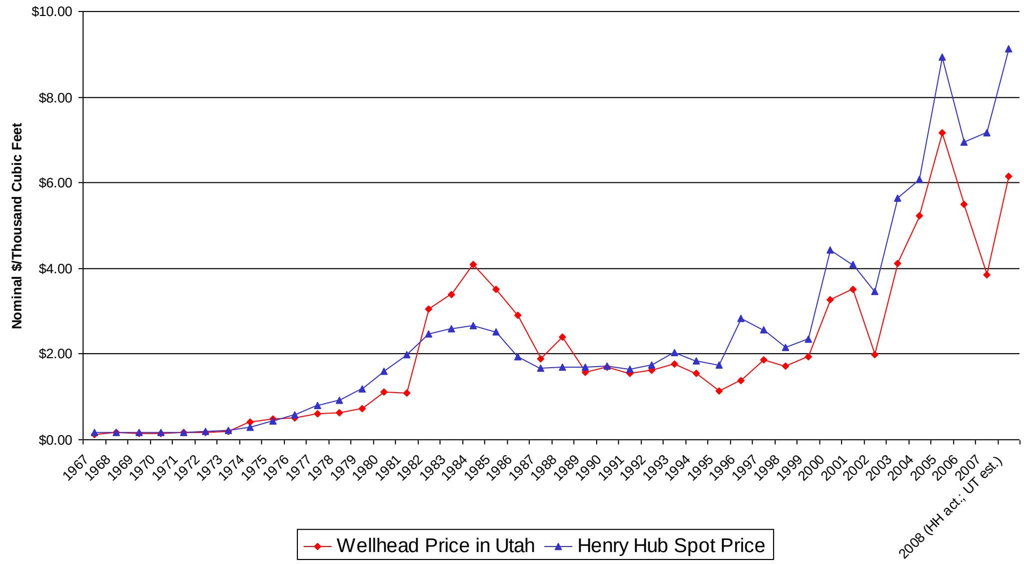

Figure 8-1: Comparison of Annual Average Utah Wellhead Prices and Annual Average Henry Hub Prices

Prior to the late 1990s, annual average Utah wellhead prices do not track annual average Henry Hub prices. This is due to the fact that Utah went from being a net importer of natural gas to a net exporter around this time. [166] However, since then, annual average Utah wellhead prices have tracked annual average Henry Hub prices. This indicates that regional fluctuations in usage would not be reflected in prices.

8.3.2. Proportion of Supply Subject to Market Prices

Another driver of DRIPE is the extent to which supply is subject to changes in market prices. If most of the supply is subject to changes in market prices (such as procured in a spot market), the price impacts will be larger. If most of the supply is procured at regulated prices or by long term contracts, the price impacts will be smaller.

[166] Isaacson, Alan E. The Structure of Utah's Natural Gas Industry. Utah Economic and Business Review. University of Utah. Available at: http://www.bebr.utah.edu/Documents/uebr/UEBR2003/Nov-Dec%202003.pdf

There are some unique characteristics driving the price of Utah's natural gas supplies. The state's largest natural gas utility, Questar Gas, provides natural gas distribution services to almost 900,000 customers in Utah, southwestern Wyoming and southeastern Idaho. However, Questar Gas is unique in that it is one of the only utilities in the United States that also owns significant reserves of natural gas. "Historically, about half of the natural gas sold to Questar Gas retail customers comes from Questar-owned supplies that are typically more-stably priced than gas purchased from other suppliers." [167] As a result, Utah is more isolated from price shifts as compared to other states and regions.

8.3.3. Scarcity of Supply

A third important driver of DRIPE is the extent to which supplies are limited by inadequate supply that cannot meet demand. In cases where supply is limited, demand reductions are more effective at alleviating pricing pressures and the impact will be greater. In general, natural gas producing states do not have the supply limitations experienced by states that are not natural gas suppliers. For example, as demand increased in Utah in 2007 and 2008 due to the installation of natural gas electric generating plants, production increased as well, such that deliveries to other states were slightly increased (see Table 8-1).

Date	Utah Natural Gas Marketed Production (MMcf)	Utah Natural Gas Total Consumption (MMcf)	Utah Natural Gas Deliveries to Electric Power Consumers (MMcf)	% In-State Consumption by Electric Power Consumers
1997	257,139	165,253	4,079	2.5%
1998	277,340	169,776	5,945	3.5%
1999	262,614	159,889	6,478	4.1%
2000	269,285	164,557	10,544	6.4%
2001	283,913	159,299	15,141	9.5%
2002	274,739	163,379	15,439	9.4%
2003	268,058	154,125	14,484	9.4%
2004	277,969	155,891	9,423	6.0%
2005	301,223	160,275	12,239	7.6%
2006	348,320	187,399	28,953	15.5%
2007	376,409	219,687	56,438	25.7%

Table 8-1: Percent of In-State Consumption by Electric Power Consumers[168],[169]

These data indicate that, with some advance notice, Utah producers can adjust to meet changing demand conditions. If demand were reduced due to energy efficiency and renewables, Utah could simply deliver a greater proportion of its production out-of-state. If out-of-state requirements were steady or decreasing, Utah producers could simply produce less in order to maintain prices. A reduction in prices would not be observed for either of these scenarios.

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[167] Questar Gas website. Available at: http://www.questargas.com/AboutQGC.php (8/5/09)
[168] Utah Natural Gas Marketed Production by End Use. Available at: http://tonto.eia.doe.gov/dnav/pet/hist/n9050ut2a.htm
[169] Utah Natural Gas Consumption by End Use. Available at: http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_dcu_sut_a.htm

8.3.4. Transport Constraints

A fourth driver of DRIPE is the extent to which limitations exist in transporting excess supply to areas of higher demand. If excess supply cannot be transported to areas of higher demand, supply shortages relative to demand will drive prices up. Demand reductions will be more effective at reducing prices if this pressure exists.

Utah is part of the Central Region natural gas production and distribution network that also includes Colorado, Iowa, Kansas, Missouri, Montana, Nebraska, North Dakota, South Dakota, and Wyoming. The states in this region are interconnected with twelve interstate natural gas pipeline systems that enter the region from the south and east and four that enter the region from the north carrying Canadian supplies. Interstate pipeline systems that are interconnected in Utah include: the Kern River Pipeline originating in Wyoming and traveling through Utah to Nevada; the Northwest Pipeline running between Utah and Idaho; the Questar Pipeline running from Utah to Wyoming; and the Colorado Interstate Gas Pipeline running from Utah to Colorado. In addition, more pipelines have been added in the Rocky Mountain region to allow natural gas to be transported to the Midwest and West Coast, forging a more integrated system between the Rockies and the rest of the country.

Historically, Utah delivery of production out-of-state has been constrained. However, the capacity of pipelines that were operating with constraints throughout the 1990s and early 2000s has been expanded over time. More than 14 billion cubic feet per day of interstate natural gas pipeline capacity was added in the Central Region between 1998 and 2008 (see Figure 8-2). Additionally, new pipelines have been constructed to connect new sources of supply to existing pipelines and facilitate interstate transport. Approximately 6 bcf per day of new intrastate pipeline was built in the Central Region between 1998 and 2008 to transport gas to the Midwest and West. While these expansions and additions have not alleviated all of the constraints, and further expansion will be required in the future, the expansions and additions have been increasing the region's ability to transport supply throughout the region as well as out of this region to other markets.

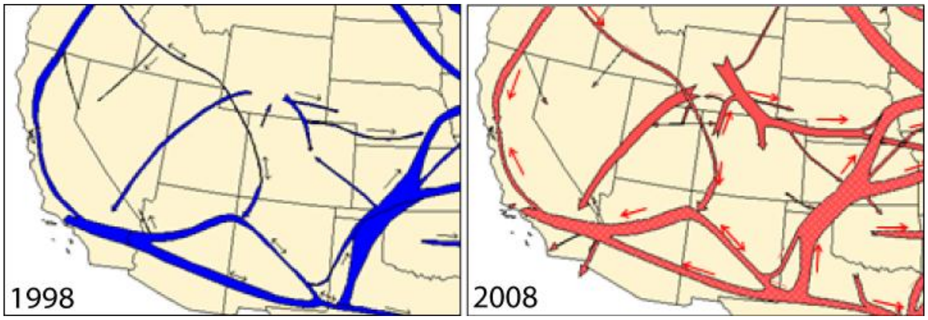

Figure 8-2: Comparison of Natural Gas Pipeline Systems in 1998 and 2008 [170]

In summary, as natural gas demand has increased, pipeline capacity has been expanded or constructed to accommodate the need to transport gas from producing areas to markets. As a result, it is unlikely that a significant price reduction would be observed in Utah due to reductions in natural gas consumption in the state. Any additional supply would be delivered out of state to expanding Midwest or West markets. Since pipeline constraints can be alleviated, it is unlikely there would be much of a gap between the reduction and the associated increase in pipeline capacity to accommodate increased out-of-state deliveries.

8.3.5. High Demand

A fifth driver of DRIPE is the extent to which demand is high. If demand is high, it is less likely that the supply will be able to meet the demand, thus driving prices up. Demand reductions in areas of particularly high demand can help bring demand more in line with supply and reduce prices. However, the Central Region does not have particularly high demand as compared to other parts of the country. The region currently consumes less natural gas than it produces and is a net exporter of natural gas.[171]

It is noteworthy that consumption by natural gas electric generating plants in Utah did double between 2005 and 2006 and further increased by approximately 65% between 2006 and 2007. The increases were due to the following:

- The addition of the Current Creek combined cycle plant that became operational in two stages in 2005 and 2006,
- the addition of the Mill Creek Generating Station unit for the City of St. George in 2006; and,

[170] Major Changes in Natural Gas Transportation Capacity, 1998-2008. Prepared by James Tobin, Office of Oil and Gas. EIA. November 2008. Available at:
http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/comparemapm.pps

[171] EIA. About U.S. Natural Gas Pipelines - Transporting Natural Gas. Natural Gas Pipelines in the Central Region. Available at:
http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/central.html (8/5/09).

- the addition the Lake Side Generation Station which came online in 2007.[172]

As a result, consumption increased from 2.5% in 1997 to 25.7% in 2007. However, the proportion of in-state consumption relative to production remained relatively stable due to increases in production.

Other states in the region are experiencing this trend as well. However, since production is able to adjust with demand, no significant changes in the price due to reductions in demand due to energy efficiency and renewable efforts would be expected. In fact, continued expansions in natural gas generation may offset any reductions due to energy efficiency and renewables and result in stable use over the next decade. Utilities are very likely to build additional gas generating stations in this region in the near future.

8.4. Conclusions

Natural gas price impacts due to demand reductions from energy efficiency and renewables in Utah will not be substantial at this time. Natural gas is priced on a national market. With low consumption relative to other regions of the country, demand reductions in the Central Region will not be significant enough to impact the national market. Marginal changes in gas consumption due to displacement by renewable energy or energy efficiency will not substantially change medium to long-term price signals in Utah or its interconnected region.

Although it was not the focus of this analysis, we would be remiss if we did not mention that natural gas price impacts due to demand reductions from national energy efficiency and renewables efforts, or potentially carbon mitigation policies, could be substantial. It is not clear what impact a national reduction in the consumption of natural gas would be on natural gas prices in Utah.

[172] Utah Geological Survey. Table 5.16.a: Natural Gas-Fired Electricity Generation in Utah by Utility Plant, 1990-2007. Available at: http://geology.utah.gov/emp/energydata/statistics/electricity5.0/pdf/T5.16a.pdf

9. Appendix B: Regional Haze Impacts and Research

9.1. Introduction and Purpose

The dramatic and iconic vistas present in Utah's urban and wilderness areas provide significant economic benefits to the state. The degree to which this benefit is realized is highly dependent on the visual experience of visitors and residents of the state; therefore maintaining good visibility is of economic importance to Utah.

Regional haze, caused by both natural and human-caused (anthropogenic) sources located both in-state and upwind, can and does episodically impair visibility for residents and visitors in Utah. Natural sources include rain, wildfires, volcanic activity, sea mists, and wind blown dust from undisturbed desert areas. Anthropogenic sources of air pollution may include industrial processes, (electric power generation, smelters, refineries, etc.), mobile sources (cars, trucks, trains, etc.) and area sources (residential wood burning, prescribed burning, wind blown dust from disturbed soils). The economic and environmental impacts from regional haze that can be attributed to Utah power-sector emissions is an externality of electric generation, and any amount that these haze impacts may be mitigated by new energy efficiency or renewable energy programs would be a co-benefit of those programs.

For the purposes of this analysis, the externality cost of regional haze attributable to power generation is not characterized. While there is a base of literature examining the economic implications of good visibility in natural areas, such as Utah’s extensive public lands and National Forests and Parks, the degree to which regional haze and poor visibility in Utah can be attributed to Utah power generation is as of yet unclear. In addition, new rules promulgated by the US EPA strive to reduce regional haze formation at National Parks and other high-value public lands through emissions controls. If electric power generators in Utah are required to apply emissions controls to reduce haze, and visibility is improved as a result, this particular external cost may be successfully internalized.

This section reviews the economic impact of poor visibility in general, the impact of haze in areas such as Utah’s parks and urban areas, the components and complexities of haze, and the current rules promulgated by the EPA to internalize the social costs of haze through emissions controls.

9.2. The Social Cost of Regional Haze and Reduced Visibility

Several researchers and the US EPA have attempted to evaluate the economic impact of poor visibility in urban areas and in natural areas. In the West, there is particular interest in achieving improved air quality in parklands where visitation often depends on good visibility. Reduced visibility has an economic impact in recreation where visitation numbers may drop if expansive views are unavailable. Low visibility also implies poor air quality (and associated health consequences), and may, to some extent, drive housing prices or interest in living in areas with better air quality. Economists have developed two methods of evaluating the social cost of visibility:

- *Hedonic price analyses* in residential areas examine how housing prices vary statistically with air quality, amongst a range of other variables. Studies are typically conducted over a locality where there is a clear gradient of air quality or visibility, as well as other housing price drivers. These studies are not able to necessarily distinguish the price differential due to a preference for better visibility from a preference for healthier air quality.
- *Contingent valuation* surveys individuals with a hypothetical trade-off between fixed price commodities and less tangible values, such as visibility. Individual willingness-to-pay is determined directly from survey results.

A meta-analysis in 2002 estimated the social valuation of air quality health and visibility from a hedonistic price analysis of housing prices.[173] The study used compiled results from 37 studies, and, based on 1990 air quality and housing prices, estimated that the poor health and visibility cost between $46-$77 billion (1991$). Citing other researchers, the study estimated that $7-$27 billion (1991$), or 15-35% of this cost could be attributed to visibility concerns or aesthetics, while the remainder was due to concerns of health, soiling, or other impacts.

The social cost of regional haze has resulted in dramatic regulation aimed at internalizing the cost of haze by controlling pollution. In 1991, Congress created the Grand Canyon Visibility Transport Commission to find mechanisms to improve air quality at the Grand Canyon and other locations on the Colorado Plateau, which includes all of Utah's National Parks. Amongst other recommendations in the resulting 1996 report, the commission suggested preventing air pollution by monitoring and potentially regulating stationary sources, as well as promoting renewable energy and increased energy efficiency.[174] In 1999, those regulations were promulgated by the EPA in the Regional Haze Rule and the Guidelines for Best Available Retrofit Technology (BART), recognizing that the burden of retrofitting high emissions sources was outweighed by the social benefit of controlling air pollution. In 2005, the EPA estimates that the rule will provide about $240 million (1999$) in improved visibility benefits each year, while preventing $8.4-$9.8 billion of heath impacts, including premature deaths. The rule is estimated to cost approximately $1.4-$1.5 billion annually (1999$).[175]

When the financial implications of the BART rule were analyzed in 2005, the EPA chose to use a contingent valuation method to estimate the recreational cost of haze.[176] The

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173 Delucchi, M.A., J.J. Murphy, D.R. McCubbin. 2002. The health and visibility cost of air pollution: a comparison of estimation methods. *Journal of Environmental Management.* 64:139-152.

174 Report of the Grand Canyon Visibility Transport Commission to the United States Environmental Protection Agency. June 1996. Available online at http://www.wrapair.org/WRAP/reports/GCVTCFinal.PDF

175 Fact Sheet – Final Amendments to the Regional Haze Rule and Guidelines for Best Available Retrofit Technology (BART) Determinations. Available online at http://www.epa.gov/visibility/fs_2005_6_15.html

176 Chestnut, L.G., and R.D. Rowe. 1990a. Preservation Values for Visibility Protection at the National Parks: Draft Final Report. Prepared for Office of Air Quality Planning and Standards, U.S. Environmental

study estimated the demand for visibility in National Parks in California, the Southwest, and the Southeast through a survey of individuals in five states. There are a number of caveats and assumptions in this type of study related to (a) how individuals choose to characterize their own preferences versus the preferences of others, (b) the distinction (or lack thereof) between aesthetic valuation and concern for associated health impacts of poor air quality, and (c) the visibility value of the particular areas featured in the survey. Extrapolating the results of this survey to all Class 1 areas (National Parks and other high value public lands), the EPA determined that the implementation of the Clean Air Visibility Rule (CAVR) would result in benefits of $84-$240 million (1999$), annually.[177] The map in Figure 9-1 shows the distribution of some of these benefits in the Class 1 areas examined by the valuation study.

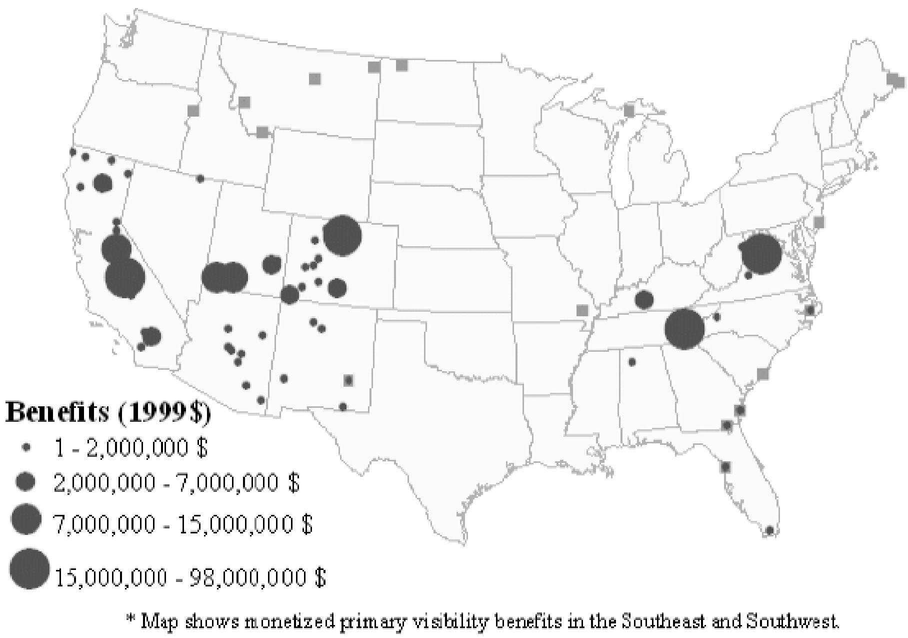

Figure 9-1: EPA estimated benefits of the Clean Air Visibility Rule in Class 1 areas in five states. Benefits are in 1999$.[177]

While the valuation of visibility is feasible, linking poor visibility and regional haze to specific emissions sources requires complex models, unavailable for this preliminary study. Delucchi *et al.* (2002, referenced above) estimates that visibility concerns are 21%-50% as valuable as health (from a social cost standpoint). In the context of this study, we do not attempt to value visibility impacts in Utah.

Protection Agency, Research Triangle Park, NC and Air Quality Management Division, National Park Service, Denver, CO.

[177] U.S. EPA. June 2005. Regulatory Impact Analysis for the Final Clean Air Visibility Rule or the Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations. Office of Air and Radiation. EPA-452/R-05-004. Available online at: http://www.epa.gov/visibility/pdfs/bart_ria_2005_6_15.pdf

9.3. Regional Haze in Utah

Haze in Utah impacts both local areas and wide regions encompassing national parks and other wilderness areas in the state. The following section details haze impacts in Class 1 (public lands) regions and along the Wasatch front.

9.3.1. Class I Regions

The Clean Air Act defines mandatory Class I Federal areas as certain national parks (over 6000 acres), wilderness areas (over 5000 acres), national memorial parks (over 5000 acres), and international parks that were in existence as of August 1977.[178] Regional haze regulations have the goal of improving visibility in the 156 "Class I" areas across the US.

In Utah, there are a total of five national parks that meet the Class I criteria. These parks are:

- Arches National Park (65,098 acres)
- Bryce Canyon National Park (35,832)
- Canyonlands National Park (337,570)
- Capitol Reef National Park (221,896)
- Zion National Park (142,462)

These parks in 2008 saw approximately 5.2 million visitors.[179] In 2005, Utah and the National Park Service signed a memorandum of understanding that recognized the importance of regional solutions to improve visibility in Class I areas.[180] Predicting the timing and magnitude of regional haze affecting Class I regions would require atmospheric transport models that go beyond the scope of the current project. However, Federal regional haze regulations allow states to develop coordinated strategies and implement programs to make reasonable progress toward the goal of "no manmade impairment" in national parks and wilderness areas by reducing emissions that contribute to haze.[181]

Figure 9-2 below shows two photos taken from the same location on days which are clear (left) and hazy (right).

[178] http://www.law.cornell.edu/uscode/html/uscode42/usc_sec_42_00007472----000-.html
[179] http://travel.utah.gov/research_and_planning/visitor_statistics/2008yearendind.htm
[180] http://home.nps.gov/applications/release/Detail.cfm?ID=564

181 http://www.epa.gov/oar/vis/facts.pdf

Figure 9-2: Visibility in Bryce Canyon National Park on a clear day and a hazy day. Source: EPA

9.3.2. Wasatch Range

The Wasatch Front region is bounded to the North by the city of Ogden, and to the South by the City of Provo.[182] This 80 mile long region is located in a valley that is bounded by Wasatch Range to the east and the Oquirrh mountains to the southwest of Salt Lake City.

With population of 1.7 million in the region, the Wasatch Front region contains approximately 75% of the state's population.[183] Haze in the Wasatch Front region affects residents and vsisitors to the most populous region of the state. Meteorology, geography, and pollution form the basis for visibility impairment in the Wasatch Front region. Haze affecting the natural vistas within the state impact the enjoyment of scenic beauty of the Utah landscape by visitors. Because this reduction can significantly reduce the enjoyment of vistas, and it may influence the decision to return that can have a significant local economic impact. With 20 million visitors to the state and a $6 billion industry, tourism is a significant component to the Utah economy.[184] Local and regional pollution from stationary sources and regional transport form the basis of visibility impairment of the landscape.

In the absence of pollution, the natural visual range is approximately 140 miles in the West and 90 miles in the East. However, pollution has significantly reduced the natural visual range. In the West, the current range is 33-90 miles, and in the East, the current range is only 14-24 miles.[185]

9.4. Components of Regional Haze

Haze is made up of numerous small particles suspended in the air, known as aerosols. Small particles, less than 0.05 microns, interfere with visibility by scattering light in random directions. The physics of Rayleigh scattering preferentially interferes with blue light. [186] For example, smoke, which is made up of numerous fine particles as well as

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182 http://www.saltlakecityutah.org/salt_lake_demographics.htm
183 http://www.edcutah.org/files/Section3_Demographics_09.pdf (p.3.2)
184 Utah Office of Tourism- Annual Report. May 14, 2008.
185 US EPA. 2009. Visbility: Basic Information. http://www.epa.gov/visibility/what.html
186 Hinds, W., "Aerosol Technology Properties, Behavior, and Measurement of Airborne Particles." John Wiley & Sons, New York. 1999 (p.349)

larger ash particulates, appears bluish in direct light as the particles reflect blue light back to the viewer. However, if backlit, the same smoke takes on an orange tone because the blue components of light are scattered away from the viewer.

Larger particles, up to 2.5 microns ($PM_{2.5}$) scatter and refract light in many wavelengths. Smaller particles (0.1 to 1 micron), however, are closer in size to the wavelengths of visible light. Blue light bends and scatters around these small particles, giving a bluish and hazy look to front-lit landscapes (i.e. the sun behind the observer), and orange sunrises and sunsets. The light scattering ability of different particle sizes results in the different visual appearance of haze seen by an observer.

Small particles stay suspended in the atmosphere, and thus persist for longer time periods and over longer distances than larger particles. Haze is defined on a regional basis, rather than as a state or local issue, because small particles can be transported over extremely long distances and impact visibility in remote locations, while coarser particles tend to be deposited closer to their source and are more likely to impact local conditions. Haze may be realized in at least three different forms: intrusive plumes from local smokestacks, low-lying inversion layers that are often found around urban areas, and regional haze that obscures the view in all directions. Each of these forms of visibility impairment is a function of the nature and source of emissions and the prevailing meteorological conditions.

Fine particles may contain a variety of chemical species including organic and elemental carbon, ammonium nitrate, sulfates, and soil. Each of these components can be naturally occurring or the result of human activity. The natural levels of pollutant species will result in some level of visibility impairment that, in the absence of any human influences, will vary with season, meteorology, and geography. A significant difficulty with valuing individual contributions to regional haze is that natural levels of haze vary significantly over time, and even the formation of fine aerosols from anthropogenic sources can depend on natural phenomena, such as sunlight, temperature, and volatile organic compounds (VOC) from plants.

Pollutants commonly associated with haze formation include the following:

- **Carbon** in the form of particulates or volatile organic compounds may be emitted from both stationary and mobile sources, and organic compounds in soil. Elemental, or black, carbon contributes to visibility impairment because it readily absorbs light. The contribution of absorption by elemental carbon is generally less than 10 percent of the loss in transmission radiance. [187]
- **Sulfur Dioxide** is especially important because it contributes to the formation of sulfates, that often dominate other causes of visibility impairment, particularly in eastern states.[188] Anthropogenic sources of sulfur dioxide are predominantly

[187] Malm, W. Introduction to Visibility. Cooperative Institute for Research in the Atmosphere (CIRA), NPS Visibility Program, Colorado State University. May 1999.

[188] Abt Associates. Out of Sight: The Science and Economics of Visibility Impairment. Prepared for the Clean Air Task Force, August 2000.

from electricity generation, fossil fuel combustion, and industrial processes.[189] Once in the atmosphere, sulfur dioxide forms sulfates, which can also lead to acidic rain.

- **Nitrogen dioxides** are found in emissions from cars, trucks and buses, power plants, and off-road equipment.[190] NO_2 gas impairs visibility, and the gas reacts with VOCs to create ground-level ozone and fine particulates.

The federal government tracks haze constituents and visibility in 156 Class I areas across the country. The Interagency Monitoring of Protected Visual Environments (IMPROVE) dataset, available from 1985 through 2003 contains detailed information on multiple constituent properties, as well as visibility metrics. [191] Although the IMPROVE data solely focuses on Class I regions, the information available illustrates the level of detail to adequately monitor constituent pollutants that contribute to haze observed in Class I areas that are generally not near local sources of pollutants.

The IMPROVE data do not contain information to determine source apportionment. However, the Western Regional Air Partnership (WRAP) has conducted an analysis using the IMPROVE dataset to apportion sources in broad categories through its Tagged Species Source Apportionment and Trajectory Regression Analysis models.[192] Figure 9-3 and Figure 9-4 detail the source apportionment of emission and source categories for Utah emissions in 2002.[193] Figure 9-3 and Figure 9-4 show apportionment of major constituents in Utah as of 2002, as determined by WRAP. Left-hand columns show human-caused (anthropogenic) sources, while the right-hand columns show natural sources.

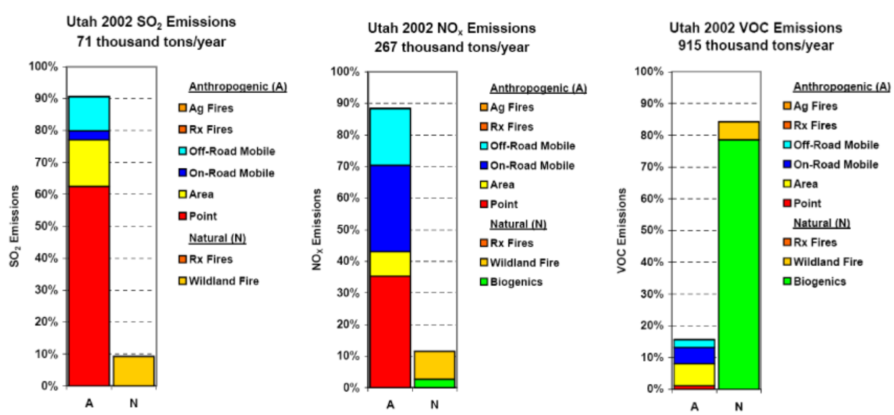

Figure 9-3: Apportionment of criteria air pollutants in Utah, 2002. Western Regional Air Partnership Data [194]

[189] http://www.epa.gov/air/emissions/so2.htm
[190] http://www.epa.gov/air/emissions/nox.htm
[191] http://vista.cira.colostate.edu/improve/
[192] http://www.wrapair.org/forums/aoh/index.html
[193] Data available at http://www.wrapair.org/forums/aoh/ars1/state_reports.html
[194] Source Western Regional Air Partnership (2002 Inventory)

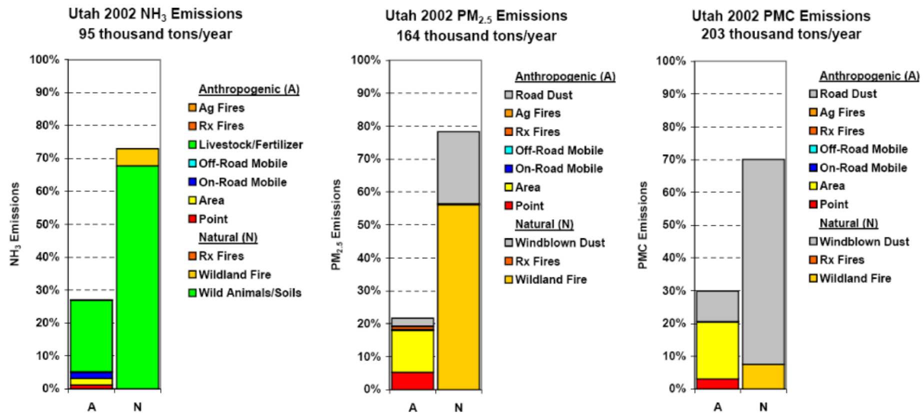

Figure 9-4: Apportionment of criteria air pollutants in Utah, 2002. Western Regional Air Partnership Data [195]

While the figures show clear differences between anthropogenic and natural contribution, the major sources of pollutants are not always anthropogenic sources. For instance, sulfur dioxide and nitrogen dioxide show clear anthropogenic contributions. In Utah, of the approximately 71,000 tons of SO_2 release in state, approximately 90% were from anthropogenic sources in 2002. Data from this study's analysis, shown in Figure 9-3 indicates that in the reference case, approximately 24,000 tons of sulfur dioxide are released annually by electric generation plants burning coal.[196] Although the data sets are different from the WRAP analysis and the probabilistic electric model, it is clear that a significant reduction in pollutant emissions from the electric generating sector will result in the reduction of pollutant levels associated with haze. On the other hand, the approximately 203,000 tons of elemental carbon released in 2002 was about 70% from natural sources. Meteorological and pollutant transport issues will still influence the formation of haze within the state.

9.5. Internalizing the Cost of Haze

Apportioning the specific point sources of haze in Utah is a complex task, requiring models of transport, as well as estimates of natural and anthropogenic causes of haze. Utah would require a comprehensive model of the formation of haze in Utah, and a determination of which population exposures are to be evaluated as an externality.

Attaching a value to haze in Utah requires estimating the social cost of visibility and other components (excluding health, which is estimated separately as a damage function). This value may be significantly different for residents of Utah and for visitors to Utah. Local residents are concentrated at the foot of the Wasatch Range and are

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[195] Source Western Regional Air Partnership (2002 Inventory)

[196] For NO_x, the Synapse reference case estimates annual emissions of approximately 68,800 tons from coal-fired generation. The WRAP Utah emission inventory for NO_x is 267,000 tons, of which point sources represent approximately 93,400 tons of emission. While not a perfect comparison, the data suggests that controlling NO_x emissions from coal-fired generation will have a beneficial impact to the amount of NO_x released within the state.

exposed to both locally generated smog as well as regional haze, and experience a cost as a preference for clear air and a perceived health benefit. Visitors to Utah prefer high visibility in natural areas, and may choose to exercise leisure dollars elsewhere if visibility remains low. Ultimately, Utah may have to determine if the preference of visitors to Utah has an economic impact on the state, and if so, how to estimate the ripple effects of those preferences through the Utah economy.

If these two steps were executed, Utah could estimate the externality associated with poor visibility and a reduced aesthetic from power generation in the state. An avoided energy analysis, similar to that conducted in the remainder of this study, could be used to determine how much haze, and therefore what value could be attached to a reduction in conventional generation.

However, these steps may be supplanted to some degree by EPA rules governing haze and the emissions associated with haze. As noted earlier in this section, in 1999 the EPA promulgated rules designed to reduce haze through emissions controls on older, large stationary sources. The EPA rules were followed up with a more recent analysis of the costs and benefits of these emissions reductions, which found that the preference for healthy air and high visibility exceeded the cost of retrofitting existing generators. A series of amendments in 2005 finalized the 1999 regional haze rule. A series of power generators will be required under this regulation to install best available technologies to control emissions which cause haze. By promulgating and enforcing this rule, the EPA will force the internalization of the cost of visibility. According to the EPA analysis of this rule, the cost of reducing emissions is significantly less expensive than the social cost of haze.

10. Appendix C: Displaced Emissions, Background

There have been a number of methodologies proposed to calculate near-term indirect emissions displacement, from simple estimates based on average emissions rates to full dispatch modeling efforts. This appendix details other methods used to estimate displaced emissions, a critical element for estimating the health externalities and co-benefits of energy efficiency and renewable energy.

10.1.1. EPA Power Profiler and Green Power Equivalency Calculator

At the national scale, the EPA publishes two calculators, one to estimate an emissions footprint for consumed electricity and the other to estimate avoided emissions for renewable energy purposes. The footprint calculator, Power Profiler,[197] estimates the consumption mix for local distribution companies (LDCs) and the equivalent emissions from that generation. The footprint is not a displaced emissions estimator, but is often used for the purpose by third parties.

The avoided emissions calculator, the Green Power Equivalency Calculator,[198] is meant to calculate emissions avoided by the purchase of green power on a regional scale. It operates by estimating the "non-baseload emissions rate". This emissions rate is based on the resource type and capacity factor of each electrical generating unit (EGU). It ignores all non-emitting generation (as it is usually very inexpensive to generate) and all baseload generation, or EGU which have capacity factors greater than 80%. The non-baseload emissions rate is calculated as the emissions rate of each included EGU, weighted by the capacity factor, with smaller capacity factors receiving greater weight.[199]

An average regional emissions rate (er_{avg}) would be calculated as follows:

$$er_{avg} = \sum_{i=1}^{n} E_i \Big/ \sum_{i=1}^{n} G_i$$

Where the emissions rate (er_{avg}) is equal to the sum of the emissions (E) of all generators (i) divided by the sum of the generation (G) of all generators.

The EPA non-baseload emissions rate (er_{nbl}) is calculated similarly, but counting only fossil generators with capacity factors (c) below 0.8. Note that generators with capacity factors below 0.2 receive a weight (w) of one.

$$er_{nbl} = \sum_{i=1}^{n} \left(w_i E_i\right) \Big/ \sum_{i=1}^{n} \left(w_i G_i\right)$$

$$w_i = 1 - \frac{\left(c_i - 0.2\right)}{1 - 0.8}$$

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[197] US Environmental Protection Agency. February 19, 2009. Power Profiler. http://www.epa.gov/cleanenergy/energy-and-you/how-clean.html

[198] US Environmental Protection Agency. February 17, 2009. Green Power Equivalency Calculator. http://epa.gov/grnpower/pubs/calculator.htm

[199] US Environmental Protection Agency. April 27, 2009. eGRID Users Manual. http://www.epa.gov/cleanenergy/documents/egridzips/eGRIDwebV1_0_UsersManual.pdf

The non-baseload emissions rate assumes that capacity factor is a reasonable proxy for loading order, and that larger units near the margin will contribute more to the marginal emissions rate.[200] This method of estimating a displaced emissions rate can be applied only as an annual estimation.

10.1.2. MIT Hourly Marginal Emissions Rate

In 2004, the Laboratory for Energy and the Environment at the Massachusetts Institute of Technology (MIT) published a research paper estimating emissions reductions from solar photovoltaic (PV) systems.[201] The researchers postulated that rather than using the fraction of generation that an EGU contributes to electrical generation, units which ramp up or down with increasing or decreasing system load could be defined as units which are marginal. Using historical hourly data collected by the US EPA's Clean Air Markets Division dataset (CAMD, discussed in depth in section 3.3.1), the researchers devised a complex methodology of determining which units were operating on the margin. The hourly average emissions rate from these units were taken as the hourly marginal emissions rate, or the displaced emissions rate for new RE or EE. This paper was amongst the first to suggest that the marginal emissions rate can change dramatically over time depending on the season and other exogenous variables.

10.1.3. Synapse/EPA Hourly and Annual Marginal Emissions Rate

In 2008, Synapse Energy Economics was contracted by the EPA to explore and validate options for estimating the marginal emissions rate, including using hourly methods, using only publically accessible data; a report was published in 2008.[202] The researchers explored several methods of estimating the marginal emissions rate from the CAMD dataset, and concluded that two were equally appropriate for different circumstances.

The first methodology is the regional annual average marginal emissions rate, termed the "emissions slope factor", which is simply the slope of the line fit to hourly gross generation and emissions (see Figure 10-1). The slope reflects the change in emissions per unit change in generation, on average, but does not capture hourly behavior or non-linear relationships. This method is a reasonable estimator for medium-term displaced emissions, or for estimating displacement from non-stochastic measures (such as geothermal sources or energy efficiency).

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[200] In the non-baseload emissions rate estimation, if there are two units with equal capacity factors but different capacities, the larger unit will contribute more to the displaced emissions rate than the smaller unit. If the larger unit is twice the capacity, its emissions rate will count for twice that of the smaller unit.
[201] Connors, S., K. Martin, M. Adams, E. Kern, and B Asiamah-Adjei. 2005. "Emissions Reductions from Solar Photovoltaic (PV) Systems" Publication MIT LFEE 2004-003 Report.
[202] Hausman, E., J. Fisher, B. Biewald. 2008. Analysis of Indirect Emissions Benefits of Wind, Landfill Gas, and Municipal Solid Waste Generation. US EPA, National Risk Management Research Laboratory, Air Pollution Prevention and Control Division. http://www.epa.gov/nrmrl/pubs/600r08087/600r08087.pdf

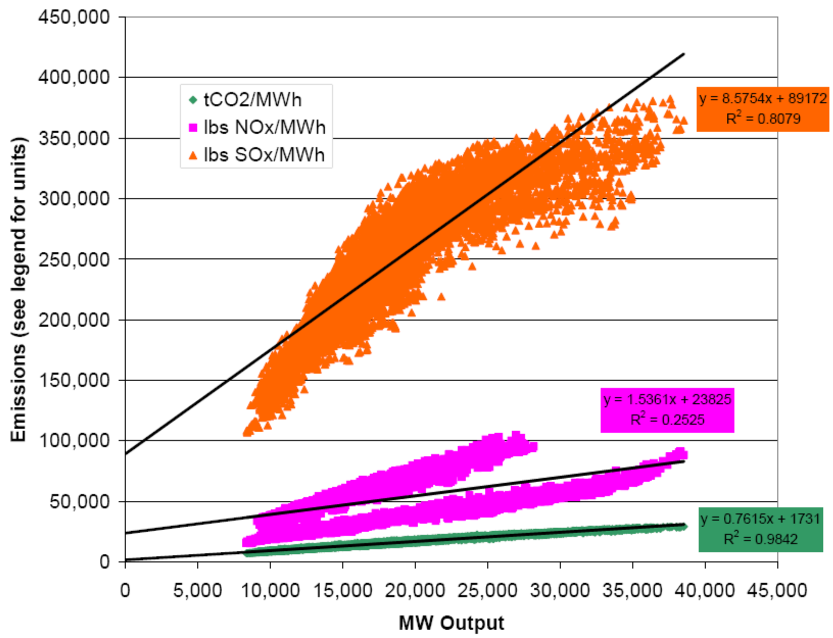

Figure 10-1: The regional Emissions Slope Factor in the RFCE (Reliability First/Central) region. Total emissions of CO2, NOx and SO2 vs. MW output for each hour of 2005 are shown. A linear line of best fit is calculated for each pollutant, and the slope of this fit determines the annual slope factor for the region. The bifurcation of the NOx data reflects the differential operations of pollution control equipment during the ozone (summer) vs. non-ozone seasons. Source: Hausman et al., 2008 (Synapse/EPA).

The second methodology strives to capture instantaneous changes in the system based on historical behavior for a reference year, following precepts introduced by the MIT research (see above). The “flexibility-weighted hourly average emissions rate” is built on the premise that each unit has an intrinsic flexibility, determined by its ramp rate and economics relative to all other generators in its region. EGU which frequently respond to changes in load by ramping up or down have a higher flexibility, while baseload EGU rarely change output. At each hour (t), the marginal emissions rate ($er_{flex,t}$) is the average emissions rate of all units (i) online in that hour, weighted by the flexibility index (F_i).

$$er_{flex,t} = \sum_{i=1}^{n} (F_i er_i) \Big/ \sum_{i=1}^{n} F_i$$

The flexibility index is calculated as the number of hours (N) that a unit is ramping divided by the number of hours in operation. Ramping (up or down) is defined as a unit changing its gross generation by at least 2.5% of its maximum generation in one hour.

$$F_i = N_{ramping,i} / N_{operating,i}$$

The flexibility-weighted hourly average emissions rate is taken as a reasonable proxy for the displaced emissions rate for new, stochastic renewable energy or demand response programs, where it is highly likely that only marginal units will respond to changes in load. This method has also been used to estimate the marginal emissions rate of wholesale markets.[203]

10.1.4. Connecticut DEP/EPA

The Connecticut DEP and US EPA contracted with Synapse to examine the impact of energy efficiency programs on emissions reductions in Connecticut from 2009 to 2020. Researchers developed a displaced generation and emissions model based on the CAMD dataset and tested several energy efficiency scenarios, as well as the implementation of rigorous emissions control technologies, to determine the combination of EE and emissions controls required to meet increasingly rigorous state air quality standards. Unlike historical-only estimations, the model needed to estimate future changes in demand and generation, including possible new generators and generator retirement. Synapse developed the Load-Based Probabilistic Emissions Model (LBPEM), which is the basis of the current research.

10.1.5. Dispatch Models

The most comprehensive method of estimating displaced emissions is by using a transmission-constrained dispatch model, explicitly calculating the most economic mix of generation (and associated emissions) based on constraints of transmission, ramp rates, and other operating parameters. These models are generally proprietary, complex, and expensive to run. Nonetheless, there are examples of dispatch models used for the purposes of estimating displaced emissions.

In 2002, Synapse compiled a displaced emissions calculator based on dispatch model runs for the Ozone Transport Commission (OTC).[204] Outputs from the runs were used to determine the marginal units, and thus the marginal emissions rate. The calculator allows users to estimate emissions saved from load control and new renewable energy.

In 2008, the National Renewable Energy Laboratory (NREL) ran a series of dispatch models for the US West designed to estimate the impact of high penetration PV on all resource generation and fossil emissions.[205] The research found that new PV primarily displaced gas throughout the West, only impacting coal generation at high penetrations. Hydroelectric generation remained unchanged on net, but shifted temporally to accommodate large amounts of peaking solar generation.

Using dispatch models can be a highly effective mechanism for determining displaced generation and emissions from energy efficiency and renewable energy, but these models are often prohibitively expensive for non-commercial entities.

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[203] Hausman, E. J Fisher, L Mancinelli, B Biewald. 2009. Productive and Unproductive Costs of CO_2 Cap-and-Trade: Impacts on Electricity Consumers and Producers. Synapse Energy Economics. Prepared for NARUC, APPA, NASUCA, and NRECA. http://www.synapse-energy.com/downloads/cap-and-trade.pdf

[204] Keith, G., D White, B Biewald. 2002. The OTC Emission Reduction Workbook 2.1: Description and User's Manual. Prepared for the Ozone Transport Commission.

[205] Denholm, P., R. Margolis, J. Milford. 2009. Quantifying Avoided Fuel Use and Emissions from Solar Photovoltaic Generation in the Western United States. Environmental Science and Technology, 43(1):226-232

11. Appendix D: Displaced generation model details: extrapolation to future loads, adding new units and retiring units

The core of the analysis, described in the main text of this document (see Chapter 3), is able to generate an assessment of emissions in a reference year. However, in future years, under different conditions, demand may increase or decrease above or below values seen today. The model needs to be able to extrapolate out to higher and lower energy requirements. In addition, the model needs to accept statistics for potential new units to accommodate growing demand and retire units according to user interest.

Because of the nature of the structure, the model is able to dynamically adapt to changes in the base case by adopting to changing loads through load growth, energy efficiency, or must-take renewables, or adding and removing generators. The extension of the model allows this functionality.

The basic concept in the following sections is that expected generation and statistics remain constant within load bins, and load bins and statistics are created for levels of demand which have not previously been experienced (i.e. loads above reference year peak, or loads reduced below the lowest troughs). [206] In addition, it is assumed that instead of units responding to demand, they are responding to a perceived demand; if another generator is retired, all other generators in the topology must fill the gap left by the retired generator.

The statistics which are gathered for the core version of this analysis have a critical shortfall, in that they are only able to portray a world in which the load falls in the dynamic range of the reference year. If projected loads extend above or below the reference year dynamic range then the non-extended version of the model is unable to identify a load bin and is unable to use the available statistics. The first expansion module extrapolates available statistics out to load categories that did not exist in the base year to estimate how existing generators would operate in these unknown conditions.

New load categories are defined for loads up to 50% above and 50% below the existing dynamic range. For each generator, the system extrapolates the probability that the unit is in operation using the first third and last third of the probability at a load period as a basis for the extrapolation. If a unit always operates at the historical peak load, then it will also always operate at any higher loads (see Figure 11-1). If a unit never operates at minimum loads, then at any loads below it will also never operate. If an extrapolated line would otherwise extend above a probability of one (or below zero), the probability is fixed at one (or zero, respectively).

[206] The constancy of the generation vs. load relationship is critical to this statistical approach. We assume that the amount of energy generated by fossil units is a relatively constant ratio, and other types of generators and transmission remain relatively constant as well.

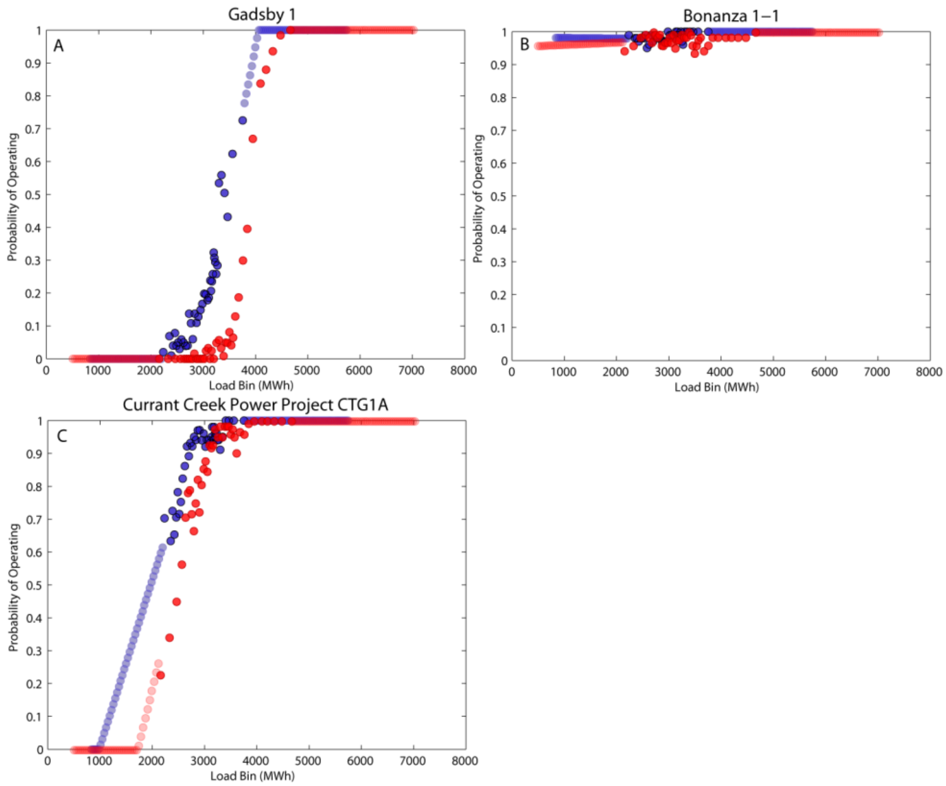

Figure 11-1: Extrapolating probability of operation in three representative units (A: Gadsby 1. B: Bonanza 1, C: Currant Creek Power Project 1). Blue dots represent historical and extrapolated fraction of hours online during Period A time periods (high hydro, low export), while red dots represent Period B time periods. Dark dots (blue and red) are probabilities derived from historical behavior, while lighter colored dots are extrapolated up and down to accommodate new peaks and troughs.

The expected level of generation is also extrapolated out for high and low load bins. The PDF of unit generation in each load bin is extrapolated up and down similarly to the probability of operation. Once these statistics are gathered, the Monte Carlo approach can be run at higher and lower loads than are otherwise available in the reference year.

In the assumption basis of the model, retiring a unit is akin to increasing load requiremnts for all other generators. When a unit is retired, the model first runs its statistics to determine what it would have generated if it were still in the system; this value is added to the generation required by all other EGU still in operation.

Adding a unit is the inverse of a retirement in the model. Since statistics for fundamentally new units are unavailable, the user selects an existing unit which will serve as a proxy new unit, externally to the model run. New units are not chosen as an optimal resource, instead they are simply feasible options from the standpoint of the model user. When a new unit is designated to begin operation, the statistics (probability of operation and PDFs of generation and emissions) from an existing unit are copied. The model runs a simulation of the new units, and then subtracts the resulting generation from the demand required of all other EGU in the system.