Final Report: Uinta Basin Energy and Transportation Study

April 2013

ACKNOWLEDGEMENTS

The Uinta Basin Energy and Transportation Study (UBETS), Phase 1, was sponsored by a Partnership between Duchesne County, Uintah County, the Uintah Transportation Special Service District (UTSSD), and the Utah Department of Transportation (UDOT). In addition to its own funds, the UTSSD applied for and received a grant from the Permanent Community Impact Fund Board. The study was led by a Steering Committee, the members of which dedicated time and energy to the successful completion of the study. Acknowledgement is given to these members of the Steering Committee:

- Jeff Holt – Chairman, Utah Transportation Commission
- Mike McKee – Commissioner, Uintah County
- Cheri McCurdy – Executive Director, UTSSD
- Edmond Bench – Chairman, Duchesne County Special Services District #2
- Shane Marshall – Region 3 Director, UDOT
- Cory Pope – Systems Planning and Programming Director, UDOT
- Craig Hancock – Region 3 Preconstruction Engineer, UDOT
- John Thomas – Project Manager, UDOT

Technical work on the study was conducted by a team led by HDR Engineering, Inc. (HDR). HDR was supported by Tammie Lucero – Director, Uintah County Economic Development, Irene Hansen – Director, Duchesne County Economic Development, Ron Winterton - Duchesne County Commission, Mark Raymond - Uintah County Commission, Darlene Burns - Uintah County Commission, InterPlan, Bio-West, CRS Engineering, CIVCO Engineering, and a team of scientists, engineers, and academics from the University of Utah's Energy and Geoscience Institute and Institute for Clean and Secure Energy, as well as the Utah Geological Survey.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

ACRONYMS, ABBREVIATIONS, AND SHORT FORMS

1P-3P	proved, probable, and possible
AADT	Annual Average Daily Traffic
ATR	automated traffic recorder
ATS	average travel speed
BBL	barrel
BCA	benefit-cost analysis
BCF	billion cubic feet
BCFE	billion cubic feet equivalent
BLM	U.S. Bureau of Land Management
BO	barrel of oil
BOPD	barrels of oil per day
BPA	Bisphenol A
BPD	barrels per day
BTS	U.S. Bureau of Transportation Statistics
cfe	cubic foot of gas
CO	carbon monoxide
CO_2	carbon dioxide
CPI	consumer price index
D factor	directional distribution factor
DOGM	Utah Division of Oil, Gas and Mining
EA	Environmental Assessment
EIA	U.S. Energy Information Administration
EIS	Environmental Impact Statement
EOG	EOG Resources, Inc.
EOP	enhanced oil production
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FHWA	Federal Highway Administration
FHWA HERS-ST	Federal Highway Administration's Highway Economic Requirements System – State Version
FTE	full-time equivalents
FY	fiscal year
GDP	gross domestic product
GHG	greenhouse gas
GIS	geographic information systems

GPT	gallons per ton
HCM	Highway Capacity Manual, 2010
HDR	HDR Engineering, Inc.
HERS	Highway Economic Requirements System
ICSE	Institute for Clean and Secure Energy
IEA	International Energy Administration
IHSGI	IHS Global Insight, Inc.
INFORUM	Interindustry Forecasting Project at the University of Maryland
I-O	Input-output
IP	initial production
K factor	planning analysis factor
LNG	liquid natural gas
LOS	level of service
MCF	thousand cubic feet
MCFD	thousand cubic feet per day
MMBOE	million barrels of oil equivalent
MMBtu	million British thermal units
MMCFE	millions of cubic feet
MP	mile post
NAICS	North America Industry Classification System
NEPA	National Environmental Policy Act
NGL	natural gas liquid
NO_x	nitrous oxides
NTFM	National Trade Flows Model
ONRR	Office of Natural Resources Revenue
PADD	Petroleum Administration for Defense District
PC/MI/LN	passenger cars per mile per lane
PCE	passenger car equivalent
PCTF	percent time spent following
PDO	property-damage-only
PFFS	percent of free-flow speed
PHF	peak hour factor
PIIP	petroleum-initially-in-place
PM	particulate matter
RAP	Risk Analysis Process
ROI	return on investment
RPC	regional purchase coefficient

SAM	social accounting matrix
SITLA	School & Institutional Trust Lands Administration
SLC	Salt Lake City
S.R.	State Route
State	State of Utah
TCFE	Page 3
TIGER	Transportation Investment Generating Economic Recovery
TRB	Transportation Research Board
UBETS	Uinta Basin Energy and Transportation Study
UDOT	Utah Department of Transportation
UGS	Utah Geological Survey
UPlan	UDOT GIS Package
U.S.	United States
USDOT	U.S. Department of Transportation
USGS	U.S. Geological Survey
USTM	Utah Statewide Travel Model
USTR	Utah Science Technology Research initiative
UTSSD	Uintah Transportation Special Service District
VHT	vehicle-hours traveled
VMT	vehicle-miles traveled
VOC	Volatile Organic Compound
WTI	West Texas Intermediate

TABLE OF REVISIONS

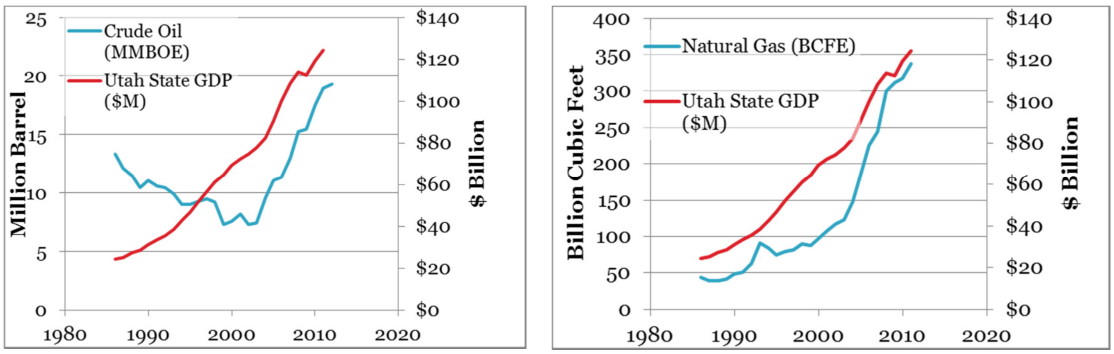
The below table records the revision history of this document.

Date	Version	Comments
07/22/13	Rev 1	Changes to the Acknowledgement section.

EXECUTIVE SUMMARY

Mining, including oil and gas extraction, represents just under 3% of Utah's gross state product.[1] The growth of economic performance in the state has tended to coincide with the growth of oil and gas production, as seen in Figure 1. Uinta Basin oil and gas sales totaled an estimated $2.5 billion in 2012, which is about 70% of Utah's total oil and gas output. The oil and gas industry accounts directly or indirectly for about half of all employment in the Uinta Basin.[2]

Figure 1: Historical Oil and Gas Production in Utah and the Gross State Product



Source: Utah Division of Oil Gas and Mining and U.S. Bureau of Economic Analysis

Note: MMBOE is Million Barrels of Oil Equivalent, BCFE is Billion Cubic Feet Equivalent, and GDP is State Gross Domestic Product.

PURPOSE OF STUDY

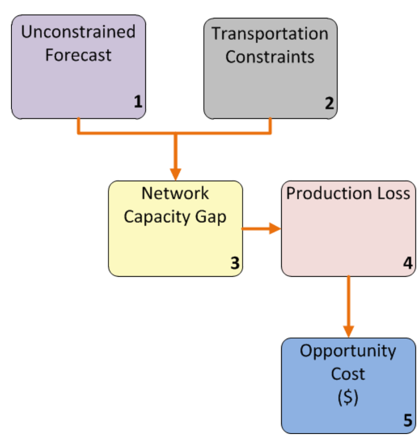
This study addresses two questions: (1) whether the volume of Uinta Basin oil and gas production in Duchesne and Uintah counties over the next three decades is likely to be constrained by limitations in the capacity of transportation infrastructure; and (2) the economic costs associated with lost oil and gas production due to any such constraints.

STUDY APPROACH

The analysis follows five steps (Figure 2).

- **Step 1** forecasts Uinta Basin oil and gas production under likely economic conditions assuming that the capacity of the transportation infrastructure will be sufficient to support such production at competitive prices. Step 1 thus constitutes a transportation-unconstrained forecast.

Figure 2: Study Approach Overview

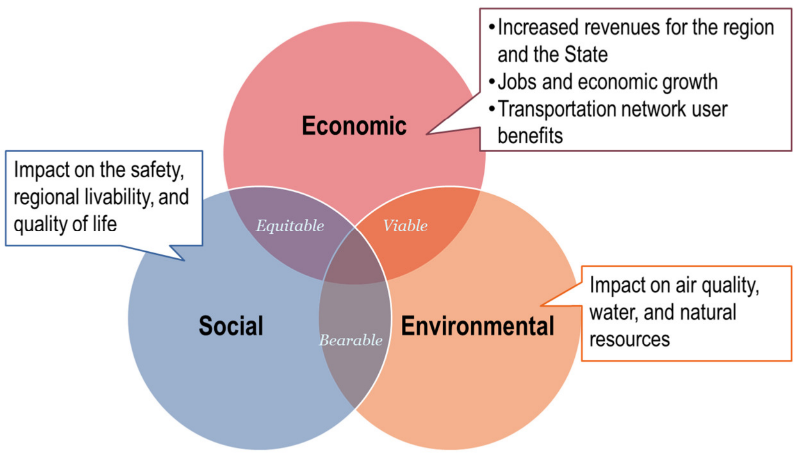


1 U.S. Bureau of Economic Analysis, Regional Data for 2010, U.S. Department of Commerce

2 Utah Department of Workforce Services, Bureau of Economic and Business Research, 2009

- **Step 2** assesses whether the capacity of the existing and planned transportation network is indeed sufficient to support the volume of oil and gas production warranted by market conditions.
- **Step 3** assesses whether any transportation constraints apparent in the Step 2 analysis effectively limit oil and gas production.
- **Step 4** quantifies any such production loss, namely the difference between unconstrained and transportation-constrained production.
- **Step 5** quantifies the value of economic opportunities unrealized due to the transportation constraints and the associated loss in production. These opportunity costs are assessed in terms of lost tax revenues to the State of Utah (State) and local governments, lost profit and other income to Utah-based businesses and land owners, foregone transportation cost savings to users of the transportation system, and environmental and social costs due to the increased congestion. This method follows a triple-bottom-line approach that accounts for social, environmental, and economic effects (see Figure 3).

Figure 3: Comprehensive Opportunity Cost Assessment Scheme – Triple-Bottom-Line Approach



TOP-LINE KEY FINDINGS

The study finds that:

- Transportation constraints on oil and gas production in the Uinta Basin are material.
- Opportunity costs to the State and local economy associated with transportation-induced production losses are likely to exceed $10 billion over the next 30 years (in present-value terms).

While we find a 10% chance that opportunity costs could be as low as $1.3 billion, we also find a 10% risk that, unless transportation limitations are resolved with new infrastructure investment, the State's economy could lose out on economic opportunities in excess of $24 billion. Even though the cost of the necessary transportation improvements might be significant, net economic gains associated with such investments are also likely to be significant enough to justify the investment.

TRANSPORTATION-UNCONSTRAINED PRODUCTION FORECAST

Estimates of existing reserves and undiscovered oil and gas resource endowments in the Uinta Basin, categorized as likely to be economical-to-recover, are summarized in Table 1.

Table 1: Summary of Resources Included in the Forecast

Resource	Economic Reserves and Resources Included in Extraction Forecast			Source(s)
	Low	Mid	High	Low
Crude oil plus NGLs[a]	200 million barrels of oil equivalent	550 million barrels of oil equivalent	700 million barrels of oil equivalent	EIA and USGS
Natural gas[b]	4,000 billion cubic feet equivalent	18,000 billion cubic feet equivalent	50,000 billion cubic feet equivalent	EIA and USGS
Oil shale[c]	77,000 million barrels of oil equivalent	111,000 million barrels of oil equivalent	226,000 million barrels of oil equivalent	UGS
Oil sands[d]	11,000 million barrels of oil equivalent	11,500 million barrels of oil equivalent	12,000 million barrels of oil equivalent	Blackett Study, UGS (1996)

Note: U.S. Energy Information Administration (EIA); U.S. Geological Survey (USGS); and Utah Geological Society (UGS).

[a] NGLs are heavier gaseous hydrocarbons: ethane (C2H6), propane (C3H8), normal butane (n-C4H10), isobutane (i-C4H10), pentanes, and even higher molecular weight hydrocarbons. When processed and purified into finished by-products, all of these are collectively referred to as NGL. NGL are valuable commodities separate from natural gas.

[b] Low and mid conventional gas only, high inclusive of conventional plus tight natural gas – 50,000 billion cubic feet equivalent Colorado School of Mines (2010).

[c] Oil shale at a minimum gallon per ton of shale grade, located a defined maximum depth from the surface. Total Uinta Basin oil shale including all densities at any grade is estimated to be 1,320,000 million barrels of oil equivalent (USGS 2010). Prospective producers indicated about 8,700 million barrels of oil equivalent on their existing holdings.

[d] Prospective producers indicated about 950 million barrels of oil equivalent on existing holdings.

Table 1, above, describes the likely-to-be-economically feasible resources included in the forecast. However, there are several estimates of resources that indicate even greater resources in the Uinta Basin. Table 2 below presents the resource estimates that are identified, but not included in the forecast.

Table 2: Summary of Upside Resource Potential Estimates, Not Included in the Forecast

Resource	Upside Resource Potential	Source(s)
Crude oil plus NGLs	N/A	
Natural gas	110,200 billion cubic feet equivalent (with tight and shale gas)	Colorado School of Mines
Oil shale	1,320,000 million barrels of oil equivalent (all qualities)	USGS
Oil sands	28,000 million barrels of oil equivalent (all Utah)	Institute for Clean and Secure Energy

N/A indicates no higher estimate identified than the resource estimates included in the forecast (see Table 6)

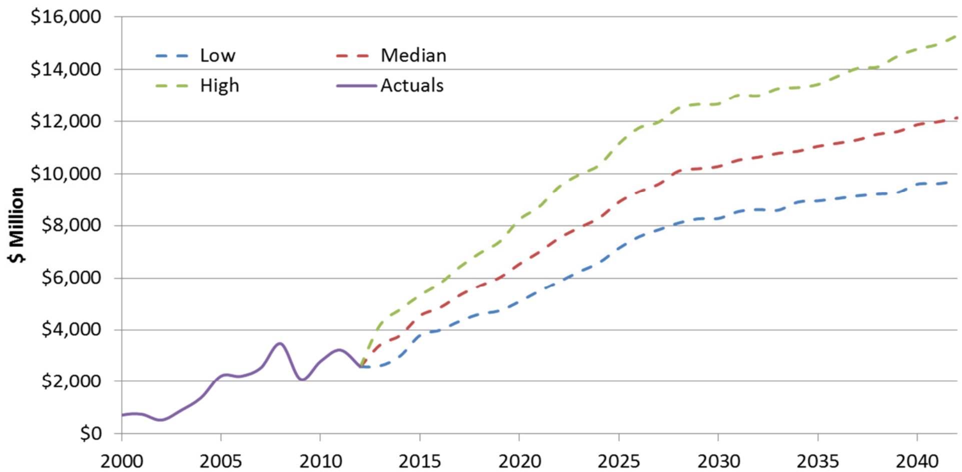
In addition to conventional oil and gas resources, the Uinta Basin has significant, untapped unconventional resources[3] that have only recently become likely-to-be economically viable due to new technology and rising commodity prices. The total estimated amount of unconventional resources far

[3] The designation of conventional and unconventional resources relates to the likely extraction technique and not the inherent nature of the resources themselves. Oil shale, gas shale, and oil sands are classified in this study as unconventional resources. These are considered unconventional because they cannot be produced by drilling and stimulation.

exceeds conventional resources. The unconstrained forecast indicates that total liquids production (as opposed to gas) from the Uinta Basin will more than double by 2022, with about half of future production increases attributable to the development of unconventional resources.

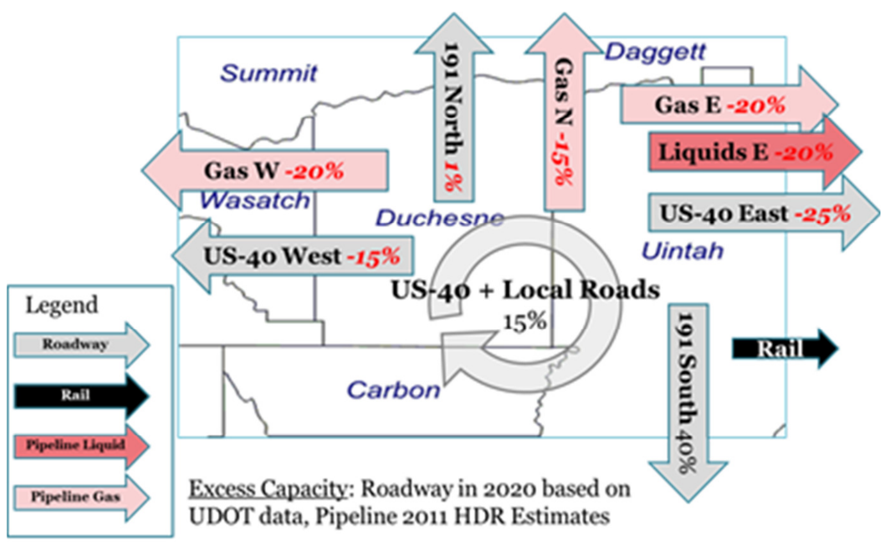
Taking increased production together with expected growth in the real price of energy commodities[4], the value of energy production, expressed in 2012 dollars, is likely to more than double between 2012 ($2.4 billion per year) and 2023, if limited transportation capacity does not constrain growth. The full 30-year estimate, through 2042, is provided below in Figure 4.

Figure 4: Unconstrained Forecast of Production Value



TRANSPORTATION-CONSTRAINED PRODUCTION FORECAST

Figure 5: Transportation Capacity Shortfalls in 2020



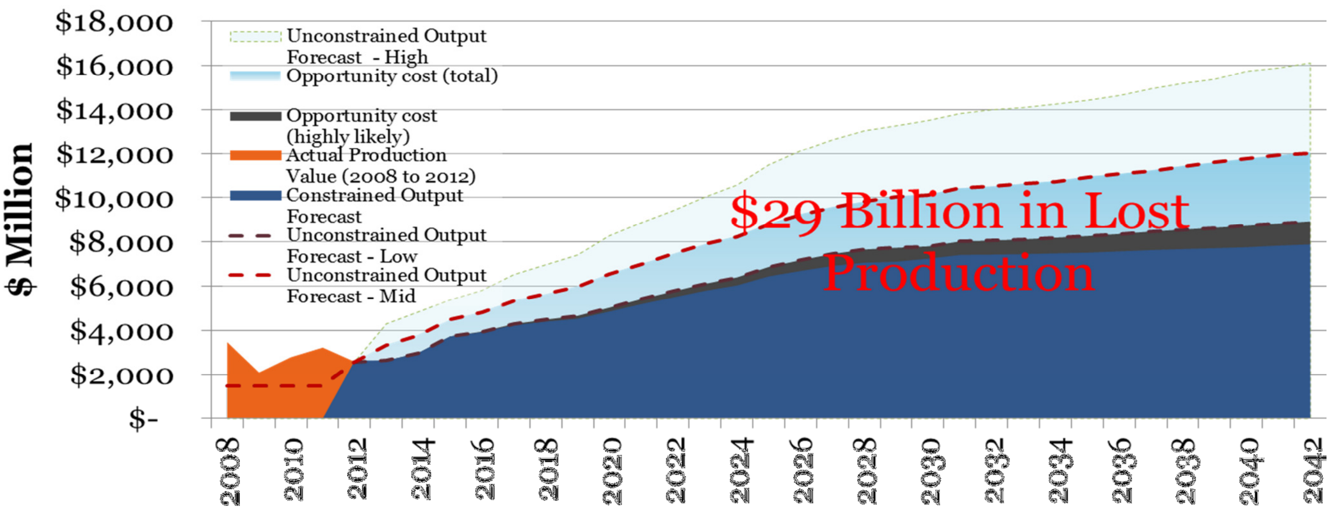
Existing pipelines are already at or near capacity, and the nature of the crude oil produced in the Uinta Basin, described as black wax or waxy crude due to its high paraffin content, limits the effectiveness of pipelines for its transportation—it must be kept warm (above 110 degrees Fahrenheit) or it hardens to the consistency of candle wax. The only rail line in the Basin is a short-line railway dedicated to transporting coal that provides no real access outside the Basin. Planned transportation improvements over the 30-year study period are limited to minor roadway improvements,

[4] Readers should note that while the expected dollar value of oil and gas is a significant driver of the study findings, the study relies on external commodity price forecasts and does not develop an alternative price forecast methodology.

namely passing lanes and a roadway widening project. The traffic forecast model, incorporating traffic related to oil and gas development, indicates that, by 2020 demand will exceed capacity on almost all of these facilities. As the transportation system becomes more constrained, investment in and development of Basin energy resources is likely to slow.

These capacity limitations will result in a loss of 12% of potential production over the next 30 years, or a cumulative loss of nearly $30 billion[5] of commodity value (Figure 6).

Figure 6: Estimated Production Gap Due to Transportation Constraints



Forecast Level	Total (Undiscounted)	Present Value at 3%
Low	$14.7 billion	$8.1 billion
Mid	$29.0 billion	$15.8 billion
High	$52.8 billion	$29.0 billion

OPPORTUNITY COSTS ASSOCIATED WITH LOST PRODUCTION DUE TO TRANSPORTATION CONSTRAINTS

Opportunity costs associated with the production loss described above include tax revenues, private rents and royalties, jobs, transportation user cost savings, and environmental and safety effects. These result in a present value of more than $10 billion of net effects and almost 27,000 full-time-equivalent jobs (Table 3).

[5] Median undiscounted “gap” between the transportation constrained and unconstrained forecasts. The high and low gap values are $15 billion and $53 billion, respectively.

Table 3: The Opportunity Cost of Constrained Oil and Gas Transportation Capacity in the Uinta Basin, Present Value[a] (over 30 Years)

Revenues and User Cost Savings ($ Million)		Environmental and Social Costs ($Million)		Macroeconomic Impact	
Profit, rents, dividends, and private royalties[b]	$3,784	Site emissions and ecological impacts	($1,246)	Total regional output, $ Million	$34,794
State and local tax revenue	$2,756	Vehicle emissions	($24)	Total labor income, $ Million	$11,791
User cost savings	$4,943	Safety impacts	($101)	Long-term jobs[c]	26,802
Total	**$11,483**	**Total**	**($1,371)**		

Note: Does not account for costs of added transportation investment, but rather provides a basis against which to evaluate whether the cost of additional transportation investment is justified.

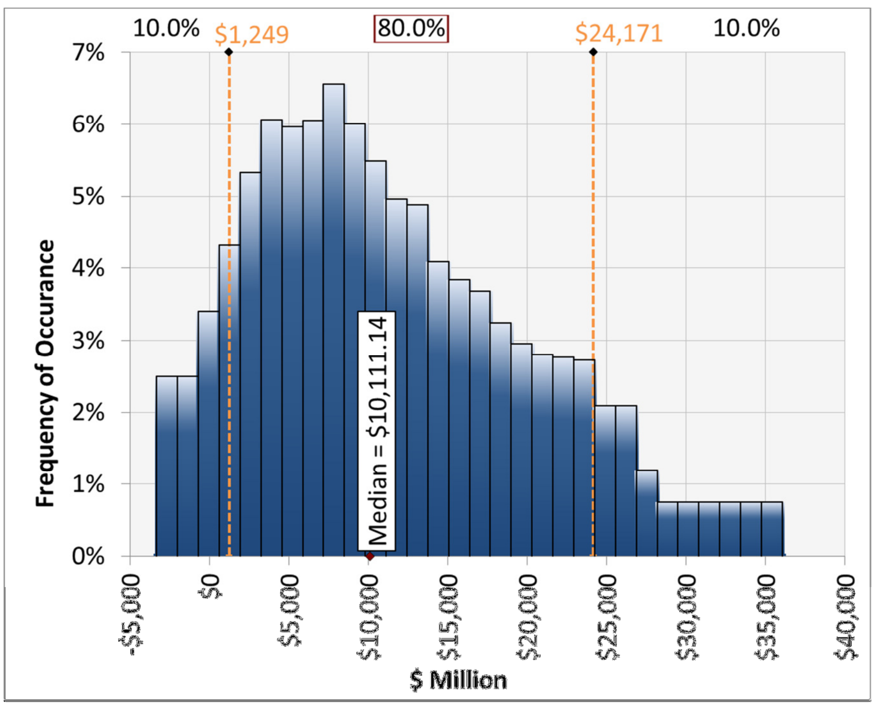
[a] 3% discount rate.

[b] Represents the portion of total macroeconomic output that is additional private citizen/corporate profit net of expenses and resource depletion.

[c] Full-time equivalent (FTE). Assumes a 10-year term of employment.

RISK ASSESSMENT

Figure 7: Net Opportunity Cost, 80% Confidence Interval



The study indicates that Uinta Basin oil and gas production is materially constrained by limited transportation capacity and that significant opportunity costs will likely arise without investment in transportation infrastructure. This outlook was developed based on conservative assumptions about resource availability, new project development, and limitations imposed by constraints other than transportation. The study also deducts from the opportunity cost analysis the potential negative environmental and social impacts associated with greater transportation availability (see Table 3). Even with this conservative approach the forecast, as described in Figure 7 above, indicates a high probability that the value of economic opportunities foregone will exceed $10 billion over the next three decades.

Uncertainty in key underlying assumptions is such that there is an 80% probability that opportunity costs will fall between $1.3 billion and $24.2 billion, as shown in Figure 7 above. Uncertainties that contribute to this range include how quickly natural gas prices recover, whether environmental restrictions that would limit new development are imposed on the region, whether oil prices continue to justify more expensive extraction approaches for unconventional resources, and how quickly new development opportunities become available.

1 Introduction

The Uinta Basin Energy and Transportation Study (UBETS) is being sponsored by a Partnership between four entities: Duchesne County, Uintah County, the Uintah Transportation Special Service District (UTSSD), and the Utah Department of Transportation (UDOT). Leaders and others in the communities of the Uinta Basin over the last several years have recognized growing traffic congestion on the roads in the Uinta Basin, which has come with increases in energy production. Knowing that further increases in energy production activity are on the way, the leaders began to discuss solutions to the increased traffic congestion. Potential solutions ranged from increasing pipeline capacity to increasing roadway capacity and whether railways could be part of the solution.

To address these questions the Partnership initiated the UBETS, which is aimed at developing a better understanding of the relationship between energy production and transportation in the Uinta Basin. The purpose of Phase 1 of the UBETS is to determine the economic value lost due to a transportation infrastructure that might be inadequate to fully support development of energy resources in the Uinta Basin. Phase I is designed to simply answer the question: Will future development of energy resources in the Uinta Basin be so constrained by an inadequate transportation network that investment in that transportation network is justified?

To assist with addressing this question, the Partnership engaged a team of academics, engineers, industry experts, and economists, led by HDR Engineering, Inc. (HDR). HDR has designed a process to answer the study questions in a manner that incorporates local stakeholder and industry expertise along with an understanding of the national and global energy development technologies and economics.

1.1 Project Organization

The study team, led by HDR, includes Bio-West, InterPlan, CIVCO Engineering, and CRS Engineers in critical roles as subject-matter experts, local and regional coordinators, and facilitators. An Energy Advisory Team, led by University of Utah professor John McLennan, PhD, provided specialized guidance.

The Partnership established a Steering Committee of key stakeholders to ensure that the project remains focused on achieving its primary goals under an aggressive schedule. The Steering Committee members are:

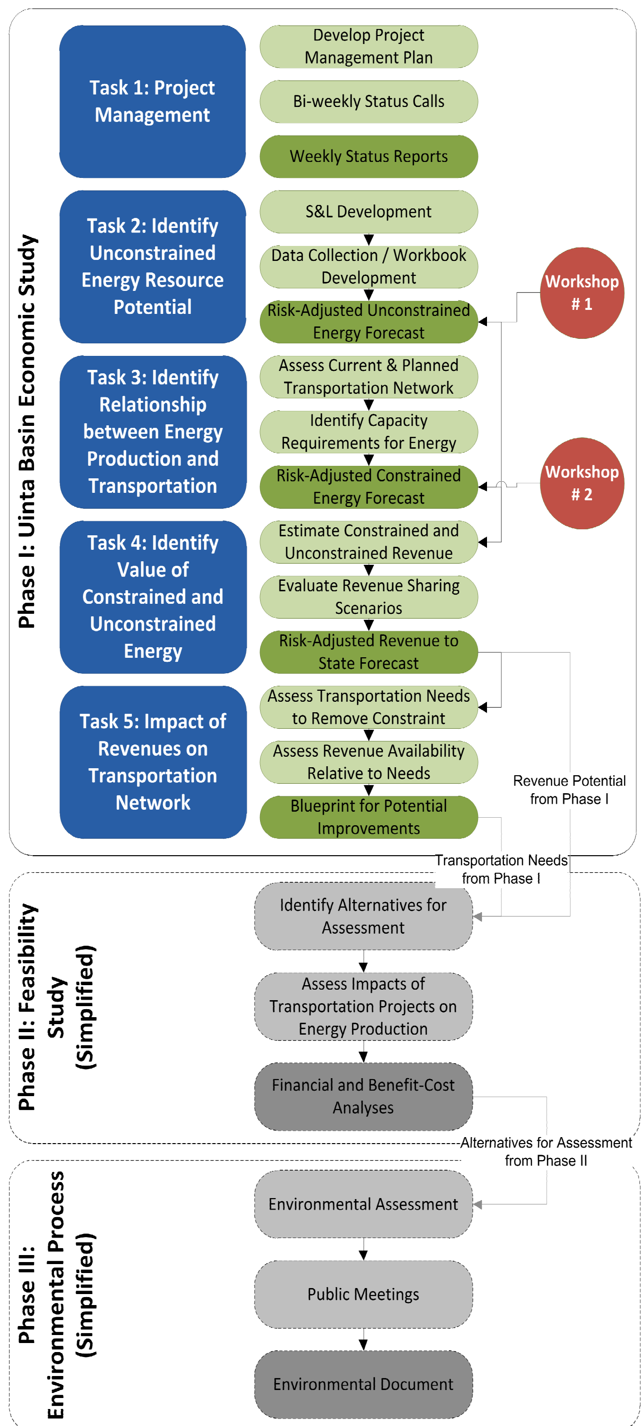
- Jeff Holt – Chairman, Utah Transportation Commission
- Mike McKee – Commissioner, Uintah County
- Cheri McCurdy – Executive Director, UTSSD
- Edmond Bench – Chairman, Duchesne County Special Services District #2
- Shane Marshall – Region 3 Director, UDOT
- Cory Pope – Systems Planning and Programming Director, UDOT
- Craig Hancock – Region 3 Preconstruction Engineer, UDOT
- John Thomas – Project Manager, UDOT

1.2 Project Goals

The objective of the UBETS is to identify the unconstrained energy resource extraction potential for the greater Uinta Basin and to understand the constraint imposed by the current and planned transportation infrastructure. To achieve this objective, we must understand the relationship between energy production and transportation capacities. The study investigates whether there is enough potential increased energy production constrained today or in the future by transportation to justify further investment in transportation infrastructure. Understanding the relationship between transportation infrastructure and energy extraction will help us assess whether existing transportation infrastructure can provide long-term solutions to the growth of energy production, or whether further investment in transportation infrastructure development is justified. For Phase I, the Partnership directed that evaluation of specific modes be avoided—this is not a study of transportation solutions; rather, this study is seeking to answer the following three questions:

- What is the likely path of growth for energy production in the Uinta Basin?
- Will transportation capacity limit the growth of energy production?
- If so, what is the opportunity cost of failing to provide adequate transportation infrastructure?

Figure 8: Overview of the UBETS' Approach



Based on the answers to these questions, we then quantify the value of investing in enhanced capacity, in terms of revenue streams back to the State and other entities, and the economic, environmental, and social costs and benefits.

1.3 Approach Summary

Our approach to this study uses a well-proven, consensus-based process that draws on the knowledge of the study team, stakeholders, and external experts to ensure the use of credible methods and reliable assumptions. This approach results in a reliable and transparent process for estimating the potential of, and transportation constraints on, the Uinta Basin area.

1.3.1 Resource Extraction Potential to the Value of Transportation Enhancements

The approach follows four key technical tasks, to address the three questions posed by this study.

1. **Identify the Uinta Basin's energy output potential.** In this task, we forecast the range of potential output assuming that transportation is not a constraint in investment decision-making.
2. **Identify the relationship between energy production and transportation.** This task consists of assessing the transportation

requirements of (a) the initial setup of wells or mine sites and (b) the ongoing operational requirements, in terms of the transportation capacity. The UBETS includes an evaluation of the existing capacity of the transportation network and programmed improvements. The result of this step is a constrained forecast, describing achievable output by year taking into account the limitations resulting from an inadequate transportation network.

3. **Estimate the potential commodity value of the gap between the constrained and unconstrained production forecast.** This task involves identifying the revenue streams associated with energy product extraction. This step results in an estimate of the revenue value of addressing the transportation constraint with added investment.
4. **Estimate capacity enhancement benefits.** In this task, we model the economic benefits and social and environmental consequences to the businesses and people of the region of alleviating all transportation constraints to production.

An overview of the approach for the Phase 1 study, along with the linkages to future phases, is provided in Figure 8 above.

1.3.2 Managing Uncertainty in Forecast Estimation

By its very nature, forecasting is complicated by a high degree of uncertainty. Although economists and subject-matter experts can make informed estimates for the future value of inputs, those estimates will never be certain. In addition, uncertainty about the robustness of those values and the specifics of complex market interactions increases as time increases. The process to evaluate the Uinta Basin production potential, transportation capacity impacts, and the opportunity costs of the capacity constraints must be an integrated approach that accounts for uncertainty and risk.

A more comprehensive uncertainty analysis (risk analysis) provides a better picture of the uncertainties than a single expected outcome by attaching ranges (probability distributions) to each input variable. The approach allows all inputs to be varied simultaneously within their distributions, thus avoiding the problems inherent in conventional sensitivity analysis.

Therefore, the UBETS incorporates HDR's Risk Analysis Process (RAP) to manage the risk associated with the forecast with respect to: (1) potential variability in inputs, and (2) a formalized risk analysis of potential event risks and their impacts.

HDR's RAP incorporates both outside expert opinion on input values and a statistical method in which inputs are expressed as a range of likely values. The stakeholder and expert workshop is a critical component of the expert opinion solicitation central to the RAP, as participants are asked to respond to the initial values (drawn from literature reviews, interviews with industry representatives, and other research) and participate in discussions that will lead the study team to refined data inputs. The end result is final estimates that present not only a most likely value, but also a probability range of possible outcomes all grounded in the consensus of multiple experts. (See Appendix C for more detail on HDR's RAP, including the statistical methods used.)

Uncertainty in the estimation of energy extraction potential is also addressed through HDR's RAP, which quantifies the uncertainties around events that could affect energy extraction potential and transportation capacities. Many possible events might—or might not—occur in the future with significant impacts on extraction of critical resources. The risk analysis process works with key stakeholders and experts to identify potential events with significant impact, the likelihood that these events will occur, and the range of their potential impacts. Key risks and uncertainties that are being incorporated into the forecasts for this project include:

- Potential pipeline breach caused by natural disaster
- Temporary ban on hydraulic fracturing (fracking) in major North American markets

- Changes in offshore drilling legislation
- Volatility in crude oil market price
- Changes in extraction technology resulting in lower costs
- Transportation disruption that impacts supply of Uinta Basin energy to market
- Increases in environmental and regulatory constraints impacting well construction (air quality, etc.)
- Increases in environmental and regulatory constraints for oil shale
- Increases in environmental and regulatory constraints for oil sands
- Increases in production costs due to resource constraints (water, sand, labor, etc.)
- Delays in permitting impacting the start of energy extraction

1.3.3 Plan of Report

This report describes the methods, data, assumptions, and results of the Phase 1 study in the following sections:

- Section 2, Summary of Data Collection Effort, describes the sources of data collected for the study.
- Section 3, Forecast Process, provides an overview of the forecast methodology.
- Section 4, Resource Estimate, summarizes the estimates of total extractable resources in the Uinta Basin used in the forecast.
- Section 5, Maximum, Time-Phased Production Forecast, describes the approach to and the results of the first step in the transportation-unconstrained forecast prior to the application of certain risks and other limitations incorporated in the unconstrained forecast.
- Section 6, Unconstrained Forecast, describes the approach to and the results of the transportation-unconstrained forecast.
- Section 7, Constrained Forecast Model, describes the approach to and the results of the forecast of energy commodity production in the Uinta Basin given the existing and planned transportation network.
- Section 8, Regional Opportunity Cost Estimation, describes the approach to and the results of the monetized assessment of impacts on the economy, natural environment, and social well-being of the estimated shortfall of transportation capacity.
- Section 9, Conclusions, summarizes the findings of the Phase 1 study.

Appendices are provided with additional supporting information:

- Appendix A: Summary of Transportation Demand and Capacity Data Collection and Estimation
- Appendix B: User Benefits and Environmental and Social Cost Analysis Data and Assumptions
- Appendix C: Risk Analysis Process Summary

2 Summary of Data Collection Effort

Data were collected to support the forecast of energy development from a variety of published sources as well as through extensive industry interviews.

2.1 Summary of Data Sources

Data used to derive preliminary input values were developed from documents from 17 different sources plus initial interviews with producers and logistics providers in the conventional and unconventional oil and gas sectors. Industry sources included financial and other corporate reports, e.g., annual reports, as well as other published data.

Table 4: Summary of Data Sources

Category	Author/Source	Date	Crude Oil	Natural Gas	Unconventional Natural Gas	Oil Sands	Oil Shale
Academic	Dr. John McLennan, University of Utah	2012	x				
Academic	Jon Wilkey, Institute for Clean and Secure Energy, University of Utah	Nov 2012				x	x
Academic	Michael Hogue, Institute for Clean and Secure Energy, University of Utah	Nov 2012	x	x			
Academic	Robert Bacon and Silvana Tordo, Energy Sector Management Assistance Program of the World Bank	2005	x				
Academic/ government	Michael Vanden Berg, Utah Geological Survey; Jennifer Spinti, Institute for Clean and Secure Energy, University of Utah	2012	x	x		x	x
Academic/ government	J. R. Dyni, U.S. Geological Survey; published in *Oil Shale*	2003	x	x		x	x
Academic/ government	Prepared for U.S. Department of Energy by Utah Heavy Oil Program, Institute for Clean and Secure Energy, the University of Utah	2007	x			x	x
Corporate	Anadarko Petroleum Corporation	2012		x			
Corporate	EOG Resources, Inc.	2004, 2011		x			
Corporate	SWCA Environmental Consultants	2012	x	x			
Government	U.S. Energy Information Administration	2012	x	x			

Table 4: Summary of Data Sources

Category	Author/Source	Date	Crude Oil	Natural Gas	Unconventional Natural Gas	Oil Sands	Oil Shale
Government	U.S. Department of Energy, Office of Fossil Energy, Office of Natural Gas Regulatory Activities	2012		x			
Government	Utah Department of Transportation	2006	x	x			
Government	Utah Geological Survey	2006, 2007, 2008, 2012	x	x	x	x	x
Non-governmental organization	F.M. Dawson, President, Canadian Society for Unconventional Gas	2010		x	x		
Corporate	Bill Barrett Corporation	2011, 2012	x				
Corporate	Ed Ryen, PE, HDR Engineering, Inc.	2012 (2)	x				
Government	Utah Department of Transportation	2012	x				
Corporate	Newfield Exploration Company	2012 (2)	x				
Corporate	Utah Science Technology and Research initiative (USTAR)	2011	x				
Corporate	Deloitte LLP	2012			x		
Corporate	IHS Global Insight, Inc.	2012			x	x	x
Corporate	US Oil Sands Inc.	2011				x	
Government	J. Wallace Gwynn and Francis V. Hanson, Utah Geological Survey	2007				x	
Academic	James T. Bartis, Tom LaTourrette, Lloyd Dixon, D.J. Peterson, Gary Cecchine, RAND Corporation	2005					x
Corporate	EcoShale™ In-Capsure Process	2010					x

2.2 Geographic Information

A key component of this study is the understanding of the burden that energy resource production imposes on the transportation network. Because the network is defined by specific geographic locations and destinations, and because production inputs and particularly reserves are in specific locations and need to be transported to specific destinations, the study must consider Uinta Basin geography. Much of the existing information on reserves, production, and transportation capacity, is captured in geographic information systems (GIS). In particular, the Utah Department of Transportation's (UDOT's) GIS package, UPlan, contains geographically coded reserves, wells, and transportation data used to determine where extraction sites are and will be and their relationship to the transportation network.

2.3 Summary of Interviews

In addition to collection of data through document research, the study team also conducted extensive interviews with industry representatives. These are summarized in Table 5.

Table 5: Entities Participating in the Industry Interviews

Entity	Description
Anadarko Petroleum Corporation	Predominantly natural gas producer and gas plant operator exporting NGL[a].
Berry Petroleum Company	Waxy crude[b] and natural gas producer.
Bill Barrett Corporation	Predominantly a natural gas producer with increasing waxy crude production.
Citation Oil and Gas Corp.	Predominantly a crude oil producer.
ConocoPhillips	Predominantly a coalbed methane producer in Carbon and Emery counties.
EOG Resources, Inc.	Waxy crude and natural gas producer.
EP Energy	Waxy crude and natural gas producer.
GASCO	Predominantly a natural gas producer.
Newfield Exploration	Predominantly a waxy crude producer.
QEP Resources, Inc.	Waxy crude and natural gas producer that operates pipeline and processing facilities.
Ute Energy, LLC (acquired by Crescent Point Energy)	Predominantly a waxy crude producer.
XTO Energy	A subsidiary of Exxon/Mobil—predominantly a coalbed methane producer and pipeline operator. Notably, however, they have drilled a horizontal well in the Mancos shale.
Utah Petroleum Association	Utah trade association representing the petroleum industry from wellhead production to refinery.
Western Energy Alliance	Regional trade association representing oil and gas producers throughout the western U.S.
Oil shale operations	Seven potential oil shale operators, of which four have existing holdings in Uinta Basin
Oil sands operations	Six potential oil sands operators, of which four have existing holdings in Uinta Basin and one is currently in process of acquiring a site

[a] Natural gas liquids (NGLs) are heavier gaseous hydrocarbons: ethane (C_2H_6), propane (C_3H_8), normal butane (n-C_4H_{10}), isobutane (i-C_4H_{10}), pentanes, and even higher molecular weight hydrocarbons. When processed and purified into finished by-products, all of these are collectively referred to as NGL. NGL are valuable commodities separate from natural gas

[b] Waxy crude is the term used for the high-paraffin crude oil which represents the majority of the crude oil currently produced in the Uinta Basin. Its high-paraffin content presents some unique challenges, e.g. to remain it a liquid state it must be kept above 110 degrees Fahrenheit; as a result it is stored and transported in insulated vessels, and transportation via pipeline is difficult. It is also known as black wax, although it is produced in the Uinta Basin in both black and yellow form.

Among the interviewed entities are production companies that individually produce 500,000 barrels of oil per year or more and those companies that produced 10 billion standard cubic feet of natural gas per year or more during 2010 from the Uinta Basin,[6] as well as potential unconventional operators and two associations representing energy commodity production interests. Participation ranged from minimal response to very detailed disclosure and substantial discussion.

A summary of key points collected from the interview process follows.

2.3.1 Resources

- Many representatives were not authorized to discuss reserves.
- Of those willing to disclose reserve and resource numbers:
    - For reserves, companies reported 16 million barrels of oil equivalent to 350 million barrels of oil equivalent and 461 billion cubic feet equivalent to 9,200 billion cubic feet equivalent of natural gas. The composite total range on oil reserves that the respondents were willing to share was 296 million barrels of oil equivalent to 396 million barrels of oil equivalent and 16,660 trillion cubic feet of natural gas.
    - For resources, companies reported 350 million barrels of oil equivalent to 800 million barrels of oil equivalent and no one exceeded the contingent resource number of 56,540 million barrels of oil equivalent for natural gas. The contingent resource for conventional crude oil should be at least 350 million barrels of oil equivalent and as high as 800 million barrels of oil equivalent.
- Price volatility is a major factor in the uncertainty of reserve quantities.

2.3.2 Operations

- Please estimate your fully imbedded cost of production per barrel or per thousand cubic feet:
    - The range of responses was $1.20 to $1.80 per million British thermal units (MMBtu), including tax, royalty, depreciation, etc. Although the range was wide, the consensus marginal cost of production was $1.25 per thousand cubic feet.
    - For oil production, the range was $7.50 to $18 per barrel of oil (BO), and the consensus appeared to be $12.50 per BO.
- What are the main drivers of your costs?
    - Water, water management, and water treatment; water was the main extraordinary cost driver.
    - Other extraordinary cost drivers were spills and electrical power. Other operational costs in typical Basin lease sites are close to operations costs in locations outside of the Basin.
- What is your currently planned timeline for expansion of operations?
    - The numerous current Environmental Impact Statements (EISs) and comments from producers indicate that between 10,700 and 24,400 wells will be drilled during the study period.

[6] Note: Interviews were conducted with firms representing the largest producers in the Basin. Minimum production levels in 2011 were used to determine which firms to include. However, readers should note that the largest producers produced many times the minimum volumes listed here.

- Currently there are approximately 10,500 active oil and gas wells in all of Utah, so this expansion in the Uinta Basin will be substantial.
- About half of these wells will be targeted at oil, with wet gas as the second target, and dry gas as the last target.
- A reliable forecast of what will actually be drilled is dependent on many factors that include price, market availability, permit status, geology, success rates, etc.

- What output level per well are you expecting?
  - For gas wells, the first-year expected average initial production (IP) range was 1,500 thousand cubic feet per day (MCFD) to 2,000 thousand cubic feet per day per well.
  - First-year cumulative production is expected to be 200,000 thousand cubic feet per day to 300,000 thousand cubic feet per day per well.
  - For vertically or directionally drilled oil wells, the first-year average production is expected to be 85 barrels of oil per day (BOPD), but could be up to 200 BOPD.
  - For horizontal wells, expected first-year average production varied from 200 to 800 BOPD with an average of 400 BOPD.

2.3.3 Constraints

- What are the main impediments to further development of the Uinta Basin?
  - The air quality issue is a primary impediment[7], in most developers' opinion. Other concerns are public safety, electrical power distribution, wildlife, need for natural gas pipeline capacity, and availability and cost of labor and materials.
  - The other concerns listed are generally less expensive and more practical to address or mitigate than the air quality issues.
  - Water injection will continue to be a problem as long as the U.S. Environmental Protection Agency (EPA) takes 18 months or more to approve water disposal and injection wells.
  - Additionally, competition from cheaper Canadian crude is a concern. Interviewees believe that a reason for reduced pricing of Canadian crude is that it must find a home, that is, there is restricted available refinery capacity for this oil.
- In what ways, if at all, is transportation limiting your investment or operations in the Uinta Basin?
  - In some cases, investment considerations are limited by truck availability and refinery capacity. As crude oil production capacity increases, this is becoming a regional and national constraint.
  - Producers would like to see local solutions, such as rail access, pipelines, upgrading facilities[8], and expanded refinery capacity.

[7] Readers should note that the Uinta Basin sometimes experiences wintertime ozone pollution and this issue could result in regulatory action that places and economic burden on oil and gas development. However, additional monitoring is currently underway and necessary to determine whether the Uinta Basin complies with air quality standards, and additional scientific research is needed to determine appropriate strategies for reducing ozone pollution.

    - Transportation to markets outside of Salt Lake City (SLC), where higher crude prices may be realized, is highly desirable and could attract incremental investment. Currently, trucking to other locations is not common, since the cost to re-heat the solidified crude oil must be considered.
    - There have been incidents when two refineries were not receiving crude oil due to seasonal turn-arounds or maintenance. When this occurs, producers must store production in tank farms or shut-in production.
    - Further, while agreements are in place by the largest producers to sell future waxy crude production increases to the SLC-based Tesoro and Holly refineries, most producers are of the opinion that the approximately 40,000 barrels of oil per day (BOPD) of increased refinery capacity of the current 175,000 BOPD to approximately 215,000 BOPD will be insufficient to handle expected production increases.
    - One producer reported that one of the existing crude pipelines was recently filled with set up crude.
- How do you view the range of modal options for transport in your operations? Do you see a significant cost differential between the Uinta Basin and other investment options with respect to modal options?
    - Producers prefer to drive on paved roads for safety and dust-control reasons.
    - The counties are generally keeping the roads in good shape, but drivers would prefer straighter and more paved roads.
    - Regardless, the largest waxy crude producer transports every barrel to market via insulated trucks, and does not rely on pipeline or rail options.

2.3.4 Market Conditions

- What are you anticipating over the next 5 to 10 years in terms of market changes that you think might change the cost and returns calculation for operations and new investment?
    - Some of the smaller producers have limited marketing capacity and rely on midstream marketers.
    - The larger oil producers sell directly to oil refineries.
    - The largest gas producers sell directly to natural gas utilities and direct market to large industrial users.
    - Most producers are not forecasting significant market changes. Several mentioned that they are not attempting to anticipate changes but are using projections based on current prices and costs with no adjustments.
    - Some appear to be resigned to accepting current conditions, and producers feel that forecasting energy prices and costs is of limited value.

[8] For the Uinta Basin, "upgrading facilities" being discussed include a facility to remove or reduce the amount of paraffin in the waxy crudes, thereby making it more feasible to transport via pipeline or conventional truck or rail cars. Upgrading facilities would also be a consideration for preliminary refinement of hydrocarbon liquids generated from oil shale or oil sands, to make the characteristics of those unconventional products more closely resemble conventional crude oil, for purposes of transportation, refinement, etc.

- Where are you selling your Uinta Basin product today/or plan to sell in the future? What is the end product you expect to be seeking to sell (crude oil, natural gas, natural gas liquids)? What time horizon are you looking at for a removal of the West Texas Intermediate (WTI) discount [9]/ the disparity between Henry Hub and Asian liquid natural gas (LNG)[10] pricing?
    - Oil producers sell to all five refineries in SLC and about 20% of output from several oil producers' product is shipped from the field via trucks to rail loading stations near Price, Utah, (Wildcat and Helper) to carry their production to markets outside of SLC.
    - Most producers reported selling to one or two of the SLC refineries.
    - Natural gas producers sell to a range of purchasers such as marketers with arbitrage positions, natural gas utilities, electric power generators, and large industrial customers. With natural gas there is likely to continue to be weak pricing from the current glut and lack of export capability.
    - Oil prices are expected to stay firm, and NGLs[11] are dependent upon the fraction.
    - All waxy crude producers would appreciate alternatives to the SLC refinery market so they could swing to other markets where they may be paid more for their product.
    - Currently, the WTI discount in SLC is 15% to 20% of the well head price, and producers feel that additional markets that could be opened by rail or pipeline would shrink that discount.

2.3.5 Technology

- How do you currently complete and stimulate your wells?
    - Some companies are not currently drilling for gas in the Uinta Basin.
    - For some, when it commences, gas well drilling will be directional (not horizontal) to hit several targets from a single pad and/or well bore.
    - Completion will include some hydraulic fracture stimulations in nearly 100% of the cases.
    - Several gas producers are continuing to drill for wet gas in order to complement gas production with high margins on NGL.
- What sorts of improvements would you like to be able to implement for stimulation and completion and secondary recovery if appropriate? Are there technologies or restrictions that are related to well construction, permitting, disposal, etc. that affect your production decisions?
    - Environmental restrictions included in federal EISs present the biggest challenge to obtaining drilling permits and air quality concerns may be the most limiting factor.

---

[9] WTI discount is reference to the difference between the price paid for West Texas Intermediate (WTI) crude oil, and the Brent spot price.

[10] Henry Hub spot price is the price of dry natural gas at the premier U.S. gas trading facility, i.e., Henry Hub; this price is currently (March 2013) about $3.50 / thousand cubic feet. Asian LNG is the price paid for liquefied natural gas delivered to Asian markets, including China, Japan, and India, and is currently about $15 / thousand cubic feet equivalent . This price differential represents a huge opportunity for U.S. natural gas producers and is driving the current push to develop more facilities for export of U.S. natural gas as LNG.

[11] NGL's are a common and important economic component of natural gas production in the Uinta Basin, as they can be separated from and sold at a premium compared to the per British thermal unit (Btu) price of pure natural gas.

- The largest oil producers currently use waterflooding, and at least two are considering enhanced oil production (EOP) using carbon dioxide (CO_2) from the region. There are large quantities of CO_2 in the areas around Price and Green River, Utah, that could be piped in via future pipelines installed in existing pipeline rights of way (ROWs) from Wellington to Myton.

- Do you see any technology that will open up currently unrecoverable resources to extraction or improve the expected rate of extraction in the next 10 years?
  - Although most producers did not see any revolutionary technology in the future, they did see continued increases in production resulting from improved practices and increasing expertise in the region.
  - There is abundant gas that would be developed using existing technologies, if the price of natural gas improves.
  - The Uinta Basin has many potential tiers of oil and gas reservoirs that still need to be characterized and assessed. For example, several producers believe they have large gas resources in deep gas reservoirs and shales that improved science and engineering will unlock. Others are continuing to find new oil production in the central part of the Uinta Basin and are experiencing dramatic increases as horizontal drilling and hydraulic fracture procedures improve. Still others see the likelihood of super extended laterals in the future, as horizontal drilling in the Uinta Basin becomes more common.
  - The geology in the Basin is complex and potentially improved technology and seismic interpretation could identify significant resources and help improve production techniques.

2.3.6 Regional Competitiveness

- How do you rate the Uinta Basin as an oil and gas area versus unconventional regions such as the Bakken (North Dakota) and Niobrara (CO / WY), or compared to conventional plays in Wyoming or Colorado?
  - The massive regulatory uncertainty associated with federal lands in the Uinta Basin is a serious impediment and inhibits production compared to opportunities in North Dakota, Colorado, and Wyoming.
  - Regardless, most producers find the return on investment (ROI) on compensation for waxy crude production attractive, and the value of the wet gas produced in the Uinta Basin enables gas producers to continue development and production of gas wells.
  - Some put the Uinta Basin as their highest ROI and others put it in the top quartile; no respondent indicated the Uinta Basin was a poor option.
  - Almost everyone felt working in North Dakota, Colorado, and Wyoming was less burdensome in the regulatory arena.
- What limitations do you face in the Uinta Basin that drive up extraction costs relative to other regions?
  - Two producers expressed concerns that EPA does not have the capacity to deal with oil and gas development in Utah. Some report that their experience leaves them concerned that stakeholders will do nothing to resolve National Environmental Policy Act (NEPA) issues in hopes that the problems will somehow go away.

  - Transportation to markets outside of SLC, where higher crude prices may be realized, is highly desirable and could attract incremental investment.
  - Because of limited route options and exposure to risk of closure due to weather, there have been incidents when two refineries were not receiving crude oil due to seasonal turn-arounds or maintenance. When this occurs, producers must store production in tank farms or shut-in production.
- How, in your experience, do the labor costs in Utah compare to other regions in which you have operations (in the U.S. and Canada)?
  - For labor, the Uinta Basin is competitive. The population in the Uinta Basin has a good work force, good availability, good work ethic, and is reasonably mobile.
  - Generally, the labor and service costs are less than in booming areas such as the Bakken (North Dakota), but are slightly higher than in mid-continent operations (Colorado, Wyoming, Texas).
  - There are concerns that the existing population will not be able to meet increased labor requirements as programs to increase drilling and production are finalized.
  - Several reported that they are currently importing skilled labor from the SLC area.
  - Most feel that the labor market will continue to tighten.

Transportation Requirements

Some points regarding transportation requirements are worthy of note:

- Most of the producers have modest active rig programs, with two to five rigs running on a continual basis. These rigs are usually staying on the lease and relocating on almost a weekly basis after each well is drilled and cased. Furthermore, much of the infill drilling will be done on existing pads. Therefore, many rig redeployments will not require transportation on the roads. These rigs are small in comparison to other areas, but, as the trend moves toward a larger proportion of horizontal wells, larger rigs that stay on location for a longer time will be required.
- All producers are moving away from transporting water by truck. In most cases, water is recycled and put to beneficial use on the lease. Much of it is transported via pipelines inside the lease. EPA has identified intensive water management and treatment as a best practice, and some expect it to become required practice on future EISs. Water production and use is highly variable due to the lifecycle of production wells, disposal wells, secondary recovery (water flood) and EOP, which makes forecasting transportation requirements associated with water difficult.

3 Forecast Process

One component of the UBETS is the generation of a forecast of total Uinta Basin production of energy commodities between 2013 and 2042. The production forecast was developed in steps and based on government data, academic studies, producer input, stakeholder input, and existing plans and permits for new production.

The production forecast is intended to provide an estimate of the expected total commodity production, given all normal and expected constraints and obstacles including transportation limitations. To derive this forecast, the analysis works through four forecast steps, the first three of which result in interim forecasts. Following are the four steps that lead to the transportation-constrained forecast.

Step 1: Resource Forecast

The first step estimates the maximum total production possible based on available resource estimates. This forecast does not include a time element and is primarily produced to ensure that the later, time-phased forecasts do not result in greater resource extraction than what current in-place estimates indicate are possible (Section 4.2).

Step 2: Maximum Time-Phased Production Forecast

The second step aggregates all information collected from the U.S. Geological Survey (USGS), the Utah Geological Survey (UGS), the U.S. Energy Information Administration (EIA), the Utah Division of Oil, Gas and Mining (DOGM), and other sources regarding current production trends; data on existing plans for new conventional well drilling and production; and production plans from potential new unconventional resource producers (oil sands and oil shale), without consideration of any obstacles or issues that might interfere with new production. This step results in an annualized maximum production forecast for each commodity considered (conventional crude oil, natural gas, oil sands, and oil shale). The study is premised on the idea, however, that a conservative forecast of production assumes that not everything will go to plan. For this reason, the maximum forecast is modified under step 3 (Section 6).

Step 3: Risk-Adjusted, Time-Phased Production Forecast (Transportation Unconstrained)

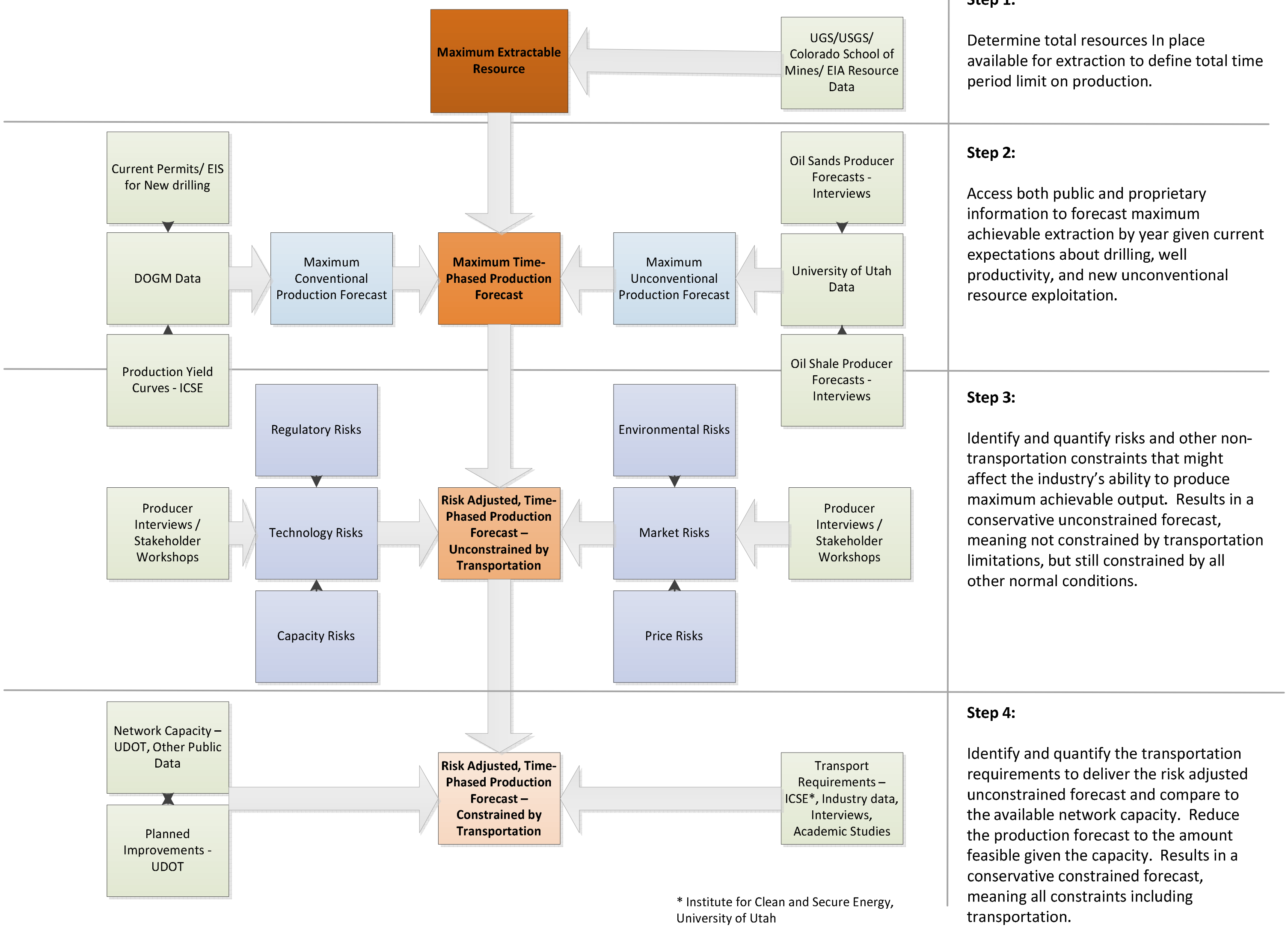
The risk-adjusted forecast is described in the study documentation as unconstrained. This has, on occasion, caused some confusion. The risk-adjusted forecast is not constrained by transportation capacity limitations, but all other constraints do apply. Under this step, the maximum production forecast is subjected to limitations and reductions, based on quantified risks. These risks include market forces that might tend to make certain production more or less attractive; technological changes that might make new extraction techniques possible; limitations imposed by environmental and other regulatory issues; and producer capacity issues that aggregate various pressures faced by producers that might make them more or less likely to implement current plans. These risks were developed and quantified in conjunction with stakeholders, study partners, and industry experts. The end result is a conservative forecast of expected production, given the maximum production forecast and risks to the fulfillment of that forecast, but assuming transportation capacity is not an issue that would limit production increases (Section 6.4).

Step 4: Risk-Adjusted, Time-Phased Production Forecast (Transportation Constrained)

The unconstrained forecast resulting from step 3 is then subjected to transportation constraints. First, the transportation requirements necessary to carry all the inputs and outputs for the transportation-unconstrained forecast are estimated. Then, these transportation needs are compared to available road, pipeline, and rail capacities, after all non-oil and gas traffic is a taken into consideration. Given shortfalls in the transportation capacity, a revised production forecast is developed based on the levels of production the network is capable of supporting. The resulting forecast can be described as the conservative, expected production forecast given transportation and all other constraints (Section 7.6).

Figure 9 below presents a relational overview of the three intermediate and the final forecast(s) and describes the inputs used in each phase.

Figure 9: Overview of the Production Forecast Approach



Step 1:

Determine total resources In place available for extraction to define total time period limit on production.

Step 2:

Access both public and proprietary information to forecast maximum achievable extraction by year given current expectations about drilling, well productivity, and new unconventional resource exploitation.

Step 3:

Identify and quantify risks and other non-transportation constraints that might affect the industry's ability to produce maximum achievable output. Results in a conservative unconstrained forecast, meaning not constrained by transportation limitations, but still constrained by all other normal conditions.

Step 4:

Identify and quantify the transportation requirements to deliver the risk adjusted unconstrained forecast and compare to the available network capacity. Reduce the production forecast to the amount feasible given the capacity. Results in a conservative constrained forecast, meaning all constraints including transportation.

4 Resource Estimate

This section provides an overview of the maximum extractable resources in the Uinta Basin. Resource data were collected through examining public agency estimates, such as from EIA, UGS, USGS, and DOGM; examination of related literature; and conducting a few interviews with subject-matter experts.

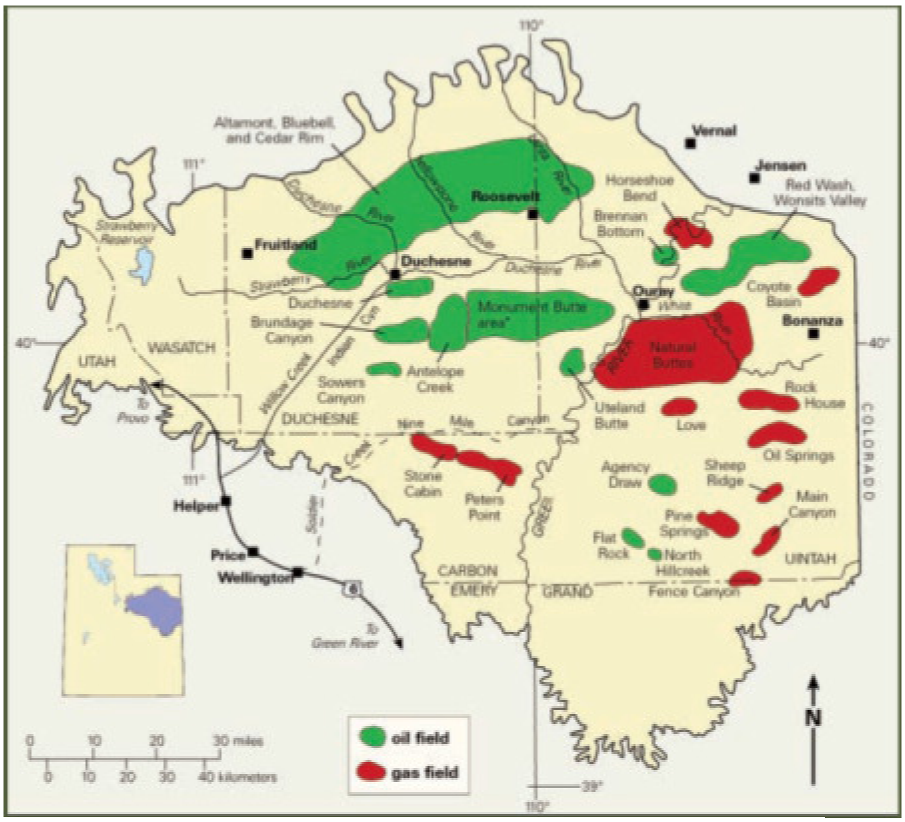
4.1 Definition of Resources

This study focuses on key export energy commodities in the Uinta Basin, which can be divided by end product (oil or gas) and extraction approach (conventional or unconventional).[12] The Uinta Basin's key resources are:

- Conventional oil (often called waxy crude or black wax)
- Conventional natural gas (including NGLs)
- Oil shale
- Gas shale
- Oil sands
- Uranium[13]

Oil shale, gas shale, and oil sands are classified in this study as unconventional resources. These are considered unconventional because they cannot be produced by drilling and stimulation. The extraction techniques required are different from the vertical well approach that has historically dominated the industry. The end product brought to market for oil shale and for oil sands is a synthetic crude oil, and the end product of gas shale is natural gas.

Figure 10: Uinta Basin Oil and Gas Fields



Source: *Utah Geological Survey, Utah! 100 years of exploration … and still the place to find oil and gas*, Public Information Series #71

[12] "Section 3: Overview of Energy Commodities, from the *Risk Analysis Process Reference Book* prepared for the November 9, 2012, Stakeholder Workshop is included in an appendix to this final *Technical Memorandum*. Summaries of key points from that section are included here to provide easy access to important project context information, if needed.

[13] Although uranium resources exist in limited amount in the Uinta Basin, they are not being included in the forecasts.

4.1.1 Conventional Oil and Gas

Current production in the Uinta Basin is primarily focused on conventional oil and gas. In 2010, Uinta County produced 6.6 million barrels of crude oil and Duchesne County produced 10.9 million barrels of crude oil of the total 24.6 million barrels of crude oil produced in Utah. Uintah County is home to the largest natural gas field in Utah, Natural Buttes, where 283 billion cubic feet (BCF) of natural gas were produced in 2010. More than 3.5 billion MCF (thousand cubic feet) of natural gas and 320 million barrels crude oil have been extracted from the Uinta Basin since 1943.[14]

4.1.2 Oil Shale and Oil Sands

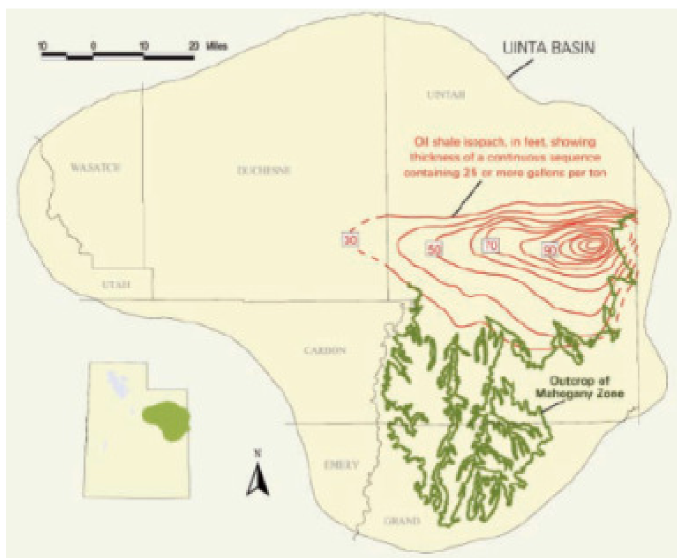
The Uinta Basin sits on a portion of what may be the world's largest oil shale deposits, contained in the Green River Formation. The oil shale was created from organic and lime-rich lake mud deposited about 50 million years ago.[15] Current estimates of the energy potential from these Uinta Basin deposits range from 50 billion to more than 300 billion barrels or more, of high-grade oil obtainable from oil shale.[16] Figure 11 shows where the majority of the Uinta Basin's oil shale deposits are located. At present, there is no commercial production of synthetic crude oil from oil shale.

The Uinta Basin is also home to most of Utah's oil sands deposits. Estimates for Uinta Basin resources range from 13,200 million BOs to 13,900 million BOs.[17] There is a small existing oil sands operation, but the output of that operation, bitumen, is used in asphalt production; it is for road paving and is not processed for crude oil. There are currently no oil sands operations used to generate hydrocarbons for energy.

4.1.3 Resource Classifications

The UBETS is concerned with total available extractable resources in the Uinta Basin, insofar as the total resources impose an absolute limit on the forecast output. The forecast is built up based on a well (for extraction of conventional resources) and mine (for unconventional resources) construction forecast, and an estimate of the annual output per site.

Figure 11: Uinta Oil Shale Map



Source: *Utah Geological Survey, Utah! 100 years of exploration … and still the place to find oil and gas,* Public Information Series #71

---

[14] As of 2011.

[15] Utah Geological Survey, *Utah! 100 years of exploration … and still the place to find oil and gas*, Public Information Series #71.

[16] Utah Geological Survey, *Utah! 100 years of exploration … and still the place to find oil and gas*, Public Information Series #71.

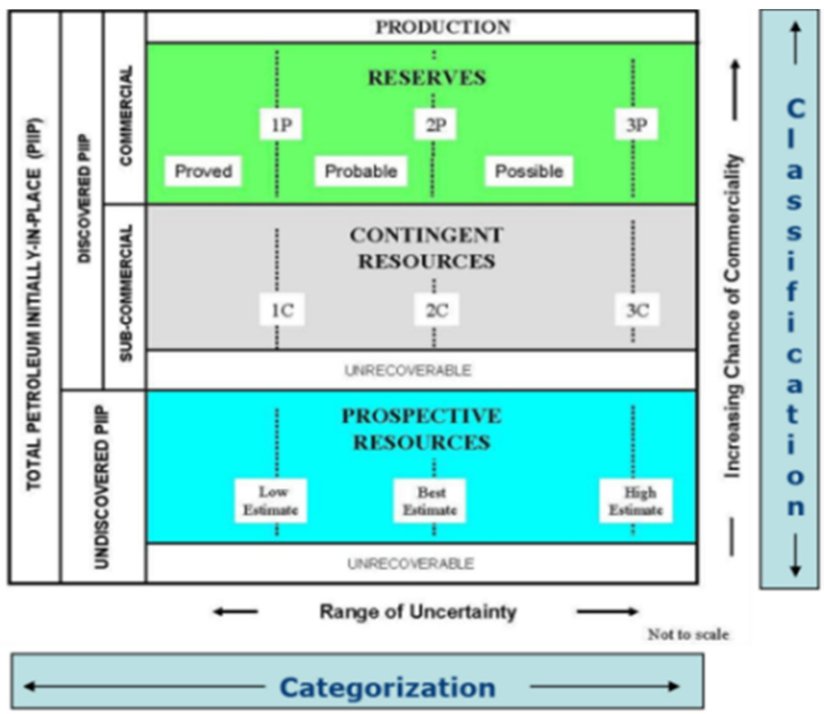
[17] Institute for Clean and Secure Energy, A technical, economic, and legal assessment of North American heavy oil, oil sands, and oil shale resources, 2007.

Resources in-place is classified in this study as:

- **Reserves:** resources that can extracted,
- **Contingent** with current technology and exiting operating conditions, and **contingent resources:** likely-to-exist**,** defined as discovered resources that are not currently extractable due to one or more of the following reasons:
  - Geological uncertainty,
  - Lack of technical solutions, or
  - Economic infeasibility.

Reserves figures cited in UBETS are based on a wide variety of sources and estimates. In some cases, these estimates are based on the legally defined categories of proved, probable, and possible (1P–3P). The UBETS has attempted to capture in its resource estimates only those deposits considered to be potentially economically feasible and recoverable. Figure 12 provides a depiction of the aggregation of the different categories of reserves and resources that are incorporated in the forecast categories.

Figure 12: Schematic of the Categorization of In-Place Resources



Source: COGEH 2nd Edition. Sept 1, 2007

It is assumed that, while proven reserves are likely to be extracted first, probable and possible reserves and contingent resources are likely to become proven reserves over time as further geological work is undertaken. Within the forecast, it is assumed that a certain percentage of the estimated contingent resources become reserves each year—as technology or costs and prices change or as further geological work is done. As a result, the total extractable limit shifts upward in each year of the forecast.

4.2 Estimation of Resource Volumes

This summary of resource data describes the estimates of likely-to-be economically recoverable resources in-place applied to the study, the sources of the data used and the application of the resource data to the overall output forecast. Readers should note that these figures do not represent all resources in-place in the Uinta Basin; rather, the listed resources indicate the segment of total resources on which producers are expected to most likely focus extraction efforts during the forecast period. Readers should not infer from this a belief on the part of the study team that resources are highly limited. Rather, these estimates represent a conservative take on the available volumes for extraction in the medium term. Readers should also note that several producers interviewed indicated that significant additional deposits were likely to become economically viable in the future.

Table 6: Estimates of Likely-to-Be Economically Feasible Resources Included in the Forecast

Resource	Economic Reserves and Resources Included in Extraction Forecast			Source(s)
	Low	Mid	High	
Crude oil plus NGLs[a]	200 million barrels of oil equivalent	550 million barrels of oil equivalent	700 million barrels of oil equivalent	EIA and USGS
Natural gas[b]	4,000 billion cubic feet equivalent	18,000 billion cubic feet equivalent	50,000 billion cubic feet equivalent	EIA and USGS
Oil shale[c]	77,000 million barrels of oil equivalent	111,000 million barrels of oil equivalent	226,000 million barrels of oil equivalent	UGS
Oil sands[d]	11,000 million barrels of oil equivalent	11,500 million barrels of oil equivalent	12,000 million barrels of oil equivalent	Blackett Study, UGS (1996)

Note: natural gas liquids (NGLs); barrel (BBL); million barrels of oil equivalent (MMBOE); billion cubic feet equivalent (BCFE); U.S. Energy Information Administration (EIA); U.S. Geological Survey (USGS); and Utah Geological Society (UGS).

[a] NGLs are heavier gaseous hydrocarbons: ethane (C2H6), propane (C3H8), butane (n-C4H10), isobutane (i-C4H10), pentanes and even higher molecular weight hydrocarbons. When processed and purified into finished by-products, all of these are collectively referred to as NGL. NGL are valuable commodities separate from natural gas.

[b] Low and mid conventional gas only, high inclusive of conventional plus tight natural gas – 50 TCFE Colorado School of Mines (2010).

[c] Oil shale at a minimum gallon per ton of shale grade, located a defined maximum depth from the surface. Total Uinta Basin oil shale including all densities at any grade is estimated to be 1,320,000 million barrels of oil equivalent (USGS 2010). Prospective producers indicated about 8,700 million barrels of oil equivalent on their existing holdings.

[d] Prospective producers indicated about 950 million barrels of oil equivalent on existing holdings.

Table 6 above describes the likely to be economically feasible resources included in the forecast. However, readers should note that there are several estimates of resources that indicate even greater resources in the Uinta Basin. Table 7 below presents the resource estimates that are identified but not included in the forecast.

Table 7: Upside Resource Potential Estimates, Not Included in the Forecast

Resource	Upside Resource Potential	Source(s)
Crude oil plus NGL	N/A	
Natural gas	110,200 billion cubic feet equivalent (with tight and shale gas)	Colorado School of Mines
Oil shale	1,320,000 million barrels of oil equivalent (all densities)	USGS
Oil sands	28,000 million barrels of oil equivalent (all Utah)	Institute for Clean and Secure Energy

*N/A indicates no higher estimate identified than the resource estimates included in the forecast (see Table 6)

The purpose of including resource volumes in the forecast is to ensure that the forecast does not assume production levels in excess of economic volumes in place. In most cases, the total volumes do not limit the forecast of production and therefore, do not factor into the output estimates. For example, if all potential oil shale producers interviewed (7) and all potential oil sands producers interviewed (6) were to implement all planned-for and hoped-for extraction sites at planned-for extraction rates, the total output during the study period would be 887 million barrels of oil equivalent from oil shale and 436 million barrels of oil equivalent from oil sands. These are well below the estimated 111 billion barrels of economically recoverable oil shale resources and 11.5 billion barrels of economically recoverable oil sands resources.

To produce the estimates of likely economically recoverable resources applied to this study, the study team collected estimates and forecasts from USGS, EIA, and UGS, and supplemented these with producers' estimates obtained through interviews and other area studies. Each of the major resource categories was estimated separately. These estimates are described below.

4.2.1 Conventional Oil

In 2002, USGS estimated the remaining Uinta undiscovered crude oil reserves (not inclusive of discovered reserves). At that time, USGS estimated 82 million barrels of oil equivalent of undiscovered petroleum product in the Basin. [18] In 2010, EIA estimated that remaining discovered liquid reserves were 151 million barrels of oil equivalent. [19] Setting aside the complexity of matching estimates from different years, the resulting estimated sum of discovered plus undiscovered resources based on these two studies would be 231 million barrels of oil equivalent. However, in 2012, EIA also estimated total Utah statewide reserves at 650 million barrels of oil equivalent of petroleum liquids. [20] Given the Uinta Basin's historical share of total statewide production (72% in 2011), it is inferred that there is an estimated Uinta Basin-area liquid reserve of about 470 million barrels of oil equivalent. Given that this EIA estimate is not inclusive of undiscovered reserves, we supplement that volume to reach our median estimate of 550 million barrels of oil equivalent. Our high and low estimates[21] form an 80% confidence interval around that median estimate, and we note that the sum of the earlier USGS and EIA estimates for discovered plus undiscovered reserves falls within our range.

Given the growth of reserves estimates over the past decade, it is likely that further exploration will result in identification of additional resources. To be conservative, however, these are not included in the median economical resource forecast.

4.2.2 Conventional Gas

Similar to conventional oil, USGS[22] and EIA[23] estimates from 2002 and 2010 indicate combined undiscovered plus discovered gas reserves of 14,599 billion cubic feet equivalent. The study team is cognizant of the Colorado School of Mines' Potential Gas Committee Study[24] which estimated resources of as much as 50,000 billion cubic feet equivalent in the Uinta Basin. This estimate constitutes the upper bound of our likely-to-be-economically-recoverable resources range. Also similar to conventional oil, a

[18] USGS Unita-Piceance Assessment Team, *Undiscovered Oil and Gas Resources of the Unita-Piceance Province of Utah and Colorado*, 2002.

[19] EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, 2010.

[20] EIA, *Utah Reserves and Supply, 2012*, see: http://www.eia.gov/beta/state/data.cfm?sid=UT#ReservesSupply

[21] High and low estimates are derived from range estimates identified in the literature supplemented with input from stakeholders.

[22] USGS Unita-Piceance Assessment Team, *Undiscovered Oil and Gas Resources of the Unita-Piceance Province of Utah and Colorado*, 2002.

[23] EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, 2010.

[24] Colorado School of Mines Potential Gas Committee, *Potential Supply of Gas in the United States*, 2010.

ratio of total EIA-estimated statewide reserves generates a Uinta Basin-area estimate of 5,584 billion cubic feet equivalent. Based on committee feedback, the midpoint estimate was adjusted to 18,000 billion cubic feet equivalent; however the 14,599 billion cubic feet equivalent estimate based on USGS and EIA studies fits within the applied range.

4.2.3 Oil Shale

Table 8 describes the oil shale resource estimates compiled for this study. Resource estimates were developed for a variety of intensities[25] based on 2008 UGS data.[26] The study team is aware of a USGS study from 2010[27] that describes oil shale resources in the Uinta Basin area. The 2010 USGS study attempts to estimate the total in-place resource of any quality. Across all depths and qualities, USGS estimates 1.3 trillion barrels of oil equivalent in place. This would not currently, however, constitute economically recoverable resources. The USGS study from 2010 (page 149) notes:

> A direct comparison cannot be made between the results of our assessment and the one released by the Utah Geological Survey (Vanden Berg 2008), that assessed in-place oil only for the single richest interval starting with the Mahogany bed, and including oil shale both above and below the bed until the interval reached oil yields of 15, 25, 35, and 50 [gallons per ton] GPT. This zone is likely to be the focus of most oil shale projects in the near future, in particular those that involve underground mining and surface retorting. Our assessment, as previously discussed, included nearly the entire oil shale interval by subdividing it into 18 separate oil shale zones, with each being assessed for regional trends in thickness, GPT, [Bisphenol A] BPA, and total barrels of oil in each township. It is therefore a more complete assessment, the results of which may be important to future in-situ retorting projects that process thick intervals of oil shale regardless of grade.

Table 8: Estimates of Oil Shale Resources Range

Range	Resource Estimate (million barrels of oil equivalent)	Constraints
Upper limit	226,000	15 GPT, more than 15 feet thick, less than 3,000 feet of cover
Middle limit	111,000	25 GPT, more than 5 feet thick, less than 3,000 feet of cover
Lower limit	77,000	25 GPT, more than 5 feet thick, less than 3,000 feet of cover, not in conflict with oil and gas, not on restricted lands
Surface mineable	51,000	15 GPT, at least 50 feet thick, no more than 200 feet of cover

Source: UGS, 2008
Note: gallons per ton (GPT).

Based on interviews with potential producers conducted for this study, it seems that deposits with 25 GPT oil shale are deemed economically recoverable and all producers interviewed are focusing their plans on near-to-surface deposits. Our mean estimate of recoverable resource is therefore based on these criteria. A

[25] Gallons of crude oil per ton of shale rock.

[26] VandenBerg, Michael, Utah Geological Survey, *Basin-wide Evaluation of the Uppermost Green River Formation's Oil Shale Resource, Unita Basin, Utah and Colorado*, 2008

[27] Johnson, R.C., (and U.S. Geological Survey Oil Shale Assessment Team), *Oil Shale Resources of the Uinta Basin, Utah and Colorado: U.S. Geological Survey Digital Data Series DDS-69-BB*, 2010

2012 USGS study estimates 93,000 million barrels of oil equivalent of economically recoverable oil shale resource, defined as shale with oil yields greater than or equal to 15 GPT. This value fits well within our applied range of economical resource.

4.2.4 Oil Sands

The UBETS partners at UGS and the University of Utah recommended the 1996 Blackett study[28] for estimates of oil sands resources. The study summarizes the results of previous work from a wide range of sources and is considered to be the most complete current picture of available resource.

Table 9: Estimates of Oil Sands Resources Range

Commodity	Resource Estimate (million barrels of oil equivalent)
Oil sands resource	11,225 to 12,043

Source: Blackett, UGS, 1996

[28] Blackett, Robert E., Utah Geological Survey, *Tar Sand Resources of the Uinta Basin, Utah, Catalogue of Deposits*, 1996

5 Maximum, Time-Phased Production Forecast

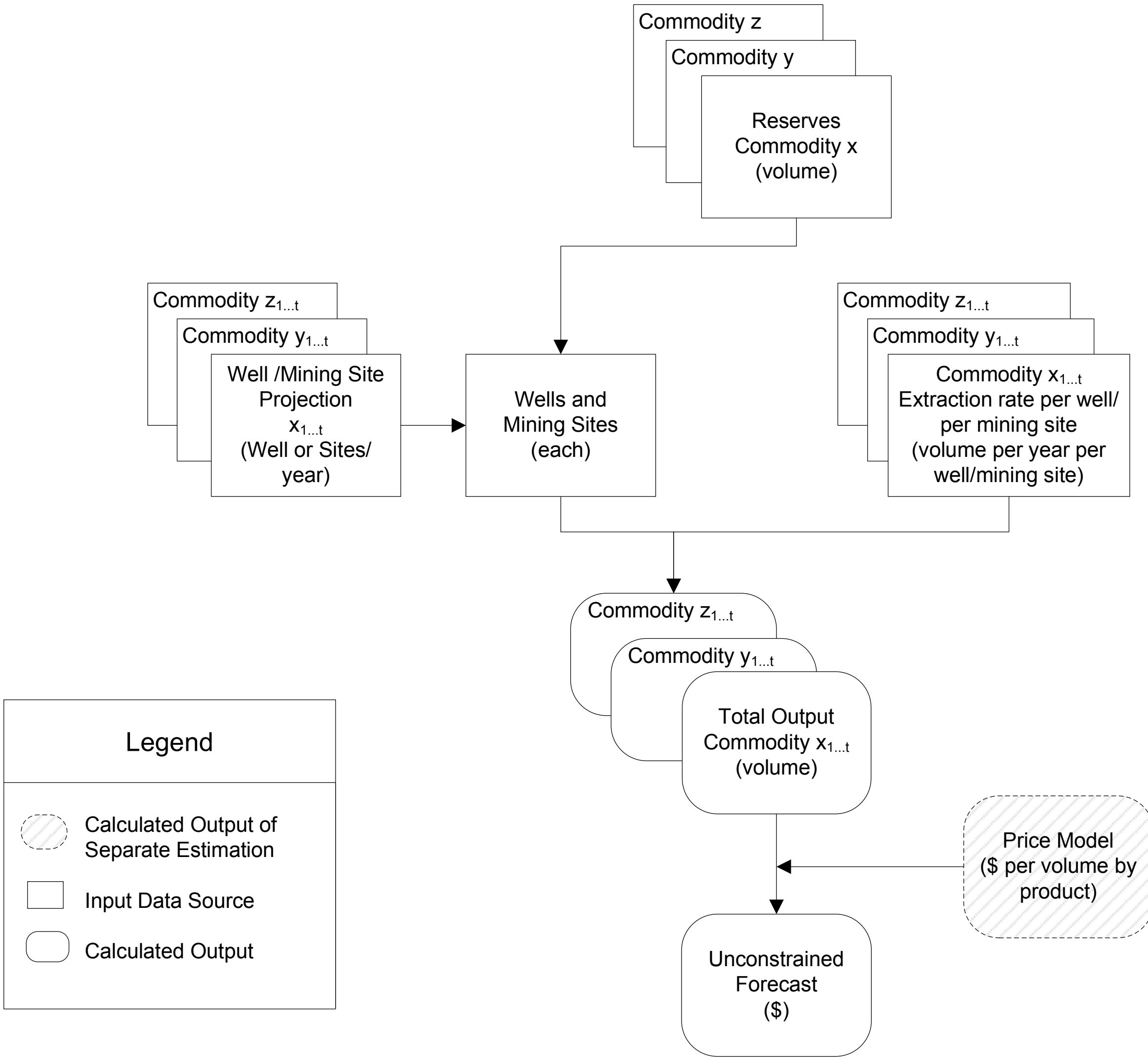
The previous section describes maximum extractable resources based on current reserve and resource estimates deemed likely-to-be economically feasible. In contrast, the maximum time-phased production forecast was produced based on all information regarding current production trends, data on existing plans for new conventional well drilling and production, and production plans from potential new unconventional resource producers (oil sands and oil shale) without consideration of any obstacles or issues that might interfere with new production plans. This step provides a maximum annual production forecast for each energy commodity considered: conventional crude oil, natural gas, NGL, oil sands, and oil shale. Actual production, which incorporates potential event risks and transportation constraints, is unlikely to exceed this forecast.

In addition, this section shows forecasts of prices and marginal costs of production for each energy commodity. Although the unit price or marginal cost might not directly impact production forecasts, they play an indirect role in producers' decisions. For instance, if the energy price falls below the marginal cost of production, producers might hesitate to build new wells or mining sites. The same price and marginal cost estimates are applied to each subsequent step of the forecasting process.

5.1 Approach to Estimation

Figure 13 below provides a structure and logic diagram for computing a maximum time-phased production forecast. Input data sources (commodities, resource and reserve estimates in the Uinta Basin, number of planned wells and mining sites, extraction rates, etc.) lead to the estimation of a production forecast by each energy commodity. This output is converted into value forecast based on price model forecast.

Figure 13: Structure and Logic of Maximum Time-Phased Production Forecast



5.2 Estimation of Energy Production from Conventional Wells

Energy resource extraction forecasts were performed separately for conventional and unconventional resources. For conventional energy resources (crude oil and natural gas), the first step was to forecast the number of wells based on existing plans. Second, the basin-wide extraction rates per well were obtained. Annual forecasts of conventional oil and gas production were estimated by multiplying the number of wells and appropriate extraction rates, which are based on the age of the well.

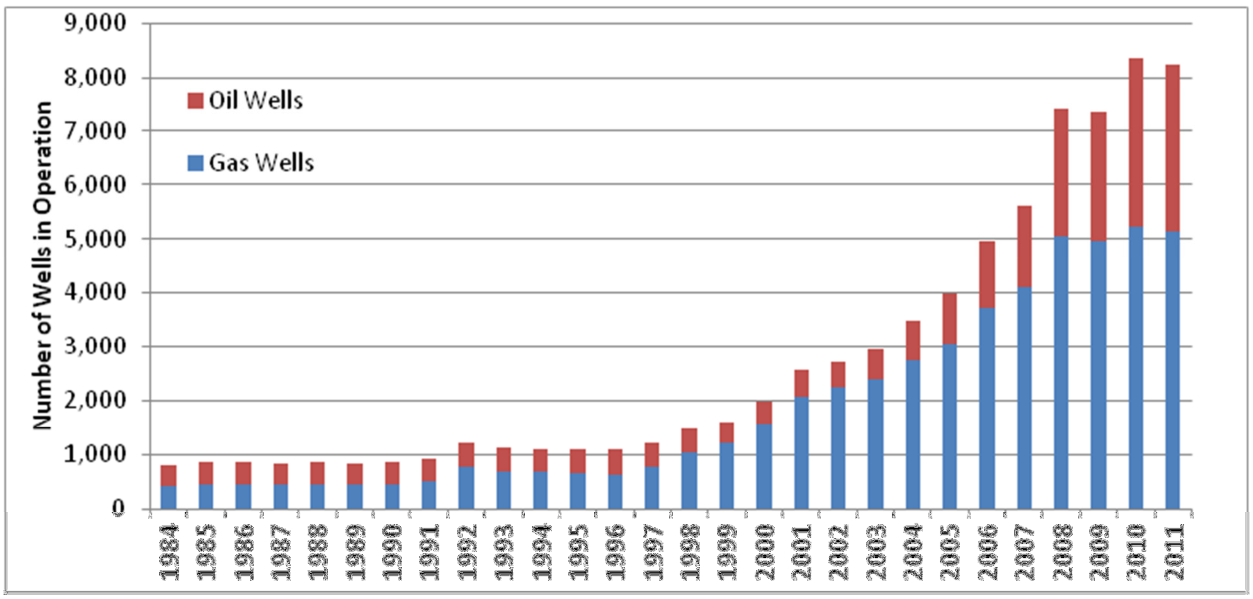
5.2.1 Projection of Conventional Oil and Gas Wells

Information regarding existing and currently planned conventional oil and gas sites was aggregated from publicly released estimates from federal and State public agencies as well as the major operators in the Uinta Basin. Figure 14 below and Table 10 below provide the historical and current number of oil and gas wells in the Uinta Basin, respectively. The total number of operating wells was fewer than 1,000 in 1986, but has grown more than eight times since. The most current UPlan data indicate that there are a total of 8,917 operating gas and oil wells in the Uinta Basin, and this number continues to grow (Table 10).

As shown in Figure 14, the well build rates have accelerated in the past few years. Michael D. Vanden Berg's "Utah's Energy Landscape" reports that "the number of oil and gas well completions in Utah averaged 879 per year over the past 7 years, a major increase over the 274 wells averaged throughout the 1990s." Many operators in the Uinta Basin have increased drilling activity in the past 2 years. Berry Petroleum drilled 54 wells in 2011, increasing their total number of wells to 508. EOG drilled 33 new wells in the Uinta Basin in 2011, making their total number of wells 1,283. In 2010, Bill Barrett had interests in 231 gross producing wells and was waiting to complete +12 more. Newfield Exploration Company plans to drill nearly 180 wells in the Uinta Basin in 2012, adding to their 2011 total of 1,659 wells. A short-term projection of oil and gas wells is also summarized in Table 11 below.

Similar to the short-term projection, a long-term forecast indicates robust development of oil and gas wells in the Uinta Basin. In April 2012, DOGM indicated there were 9,448 pending or proposed oil and gas wells in Utah; 5,733 are proposed on U.S. Bureau of Land Management (BLM) land. Public BLM records indicate that the total number of oil and gas wells projected over the next 15 to 20 years is 21,889 (Table 11).

Figure 14: Historical Uinta Basin Oil and Gas Wells in Operation by Year, 1984 to 2011



Source: DOGM via UPlan

Table 10: Existing Wells in the Uinta Basin in 2012

Existing Wells	# of Gas Wells	# of Oil Wells	Grand Total
Grand total	5,432	3,485	8,917

Source: UPlan

Table 11: Planned New Wells for Conventional Gas and Oil in Uinta Basin – Short- and Long-Term Projections

Value	Source	Approval Date	Notes
30 or more	Newfield Uinta Basin	2011	Uteland Butte; estimated number of wells in 2012
50 or more	Newfield Uinta Basin	2011	Wasatch; estimated number of wells in 2012
250 to 300	Newfield Uinta Basin	2011	Green River; estimated number of wells in 2012
800 to 900	UGS	Annual	Estimated average annual completions
400 to 900	**Total Short-Term Projection of Gas and Oil Wells in 2012**		
423	Environmental Working Group	August 2006	RDG EIS (time period unspecified)
626	Bureau of Land Management	July 2006	West Tavaputs Plateau (time period unspecified)
3,675	Bureau of Land Management	Spring 2012	Greater Natural Buttes Environmental Impact Statement (EIS) (time period unspecified)
1,300	Bureau of Land Management	Spring 2012	Gasco Uinta Basin EIS (next 15 years)
378	Bureau of Land Management	Fall 2012	Riverbend Environmental Assessment (EA) (time period unspecified)
7,025	Bureau of Land Management	2014	Greater Chapita Wells EIS (time period unspecified)
5,750	Bureau of Land Management	2014	Greater Monument Butte EIS (next 23 years)
750	Bureau of Land Management	2015	XTO Energy Field Development (time period unspecified)
249	Bureau of Land Management	Unknown	Southam, Canyon EA (time period unspecified)
664	Bureau of Land Management	Unknown	Big Pack (time period unspecified)
423	Environmental Working Group	August 2006	RDG EIS (time period unspecified)
626	Bureau of Land Management	July 2006	West Tavaputs Plateau (time period unspecified)
21,889	**Total long-term projection of gas and oil wells in the next 20 years**		

Source: Bureau of Land Management, Environmental Working Group.

In summary, Table 12 provides the number of new conventional gas and oil wells and other assumptions used for our 30-year production forecast. In the forecast model, a total of 21,900 new gas wells and 10,950 new oil wells are assumed over the next 30 years. On a per-year basis, these equate to 700 gas wells per year and 350 oil wells per year, which is similar to drilling rates of the past 5 years.

Table 12: Planned New Wells for Conventional Gas and Oil in Uinta Basin Used in the Model

Commodity	Unit	Low	Medium	High	Derivation Methodology
Natural gas	Wells	16,863	21,900	26,937	BLM data indicate that approximately 21,900 gas and oil wells are expected in the next 20 years. Assuming the same build rate, this equates to 33,000 total additional wells in the next 30 years. Out of 33,000 total wells, based on the recent build data, we applied a ratio of 2/3 to natural gas wells. Thus, 21,900 gas wells and 10,950 oil wells are forecasted for the next 30 years.
Crude oil (waxy crude)	Wells	8,432	10,950	13,469	

Source: BLM and authors' calculation

Although most of the conventional wells are vertical, the producers interviewed indicated that a certain portion of the new wells are likely to be horizontal. Table 13 provides the assumptions applied to horizontal well drilling. As is seen in the next section, the output rates of horizontal wells are significantly different from those of vertical wells. Based on producer input, the forecast assumes a 50% probability that approximately 20% of new wells will be horizontal starting in 2020.

Table 13: Horizontal Conventional Gas and Oil Well Assumptions Used in the Model

Variable	Low	Medium	High	Variable: Comment
Start year construction of horizontal well	2018	2020	2023	Anytime between 2018 and 2023, conventional oil and gas producers will drill some horizontal wells in the Uinta Basin.
Probability of horizontal wells drilling	50.0%			In each year starting from the horizontal well construction start year, there will be a 50% probability that producers will drill horizontal wells.
Portion of all wells that are horizontal	10%	20%	30%	The model assumes that, given that producers will drill horizontal wells, 10% to 30% of the total wells will be horizontal. The rest will be vertical wells.

Source: Producer interviews and stakeholder workshop inputs

5.2.2 Extraction Rates for Conventional Wells

The extraction rate estimate over time (the production decline curve) for well-extracted products drives the output forecast when combined with the estimate for number of wells/mines drilled in each year of the forecast drives the output forecast.

The extraction rates for conventional oil and gas were modeled using historical production data in the Uinta Basin. The University of Utah provided the equation for extraction rates, as presented in Equation 1. Table 14 provides the estimation parameters. Although conventional wells are designated as either oil wells or gas wells based on their main output, oil and gas wells can typically produce substantial quantities of both products. Both Equation 1 and Table 14 are specified for vertical wells—horizontal wells are assumed to have extraction rates that are 2 to 3 times greater than those of vertical wells.[29]

Equation 1: Extraction Rate for Gas and Oil from Vertical Wells

$$Q = \alpha(1 + \theta \cdot \delta \cdot t)^{-\frac{1}{\theta}}$$

Q = quantity extraction per month (oil in barrels, gas in thousand cubic feet equivalent)
t = months in well's lifetime

Table 14: Parameters for Hyperbolic Decline Curve for Extraction Rates – Per Vertical Gas and Oil Well

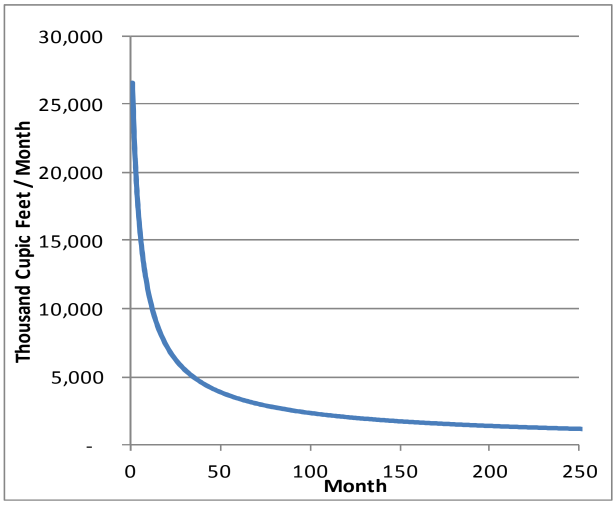
Categories	α	δ	θ
Gas production from gas wells	32,760	1.33	0.24
Oil production from gas wells	370	1.12	0.31
Gas production from oil wells	2,986	1.39	0.054
Oil production from oil wells	3,807	1.76	1.10

Source: Estimates of the Marginal Cost of Oil and Gas Production in the Uinta Basin, Michael Hogue, November 16, 2012

[29] Subject matter expert input

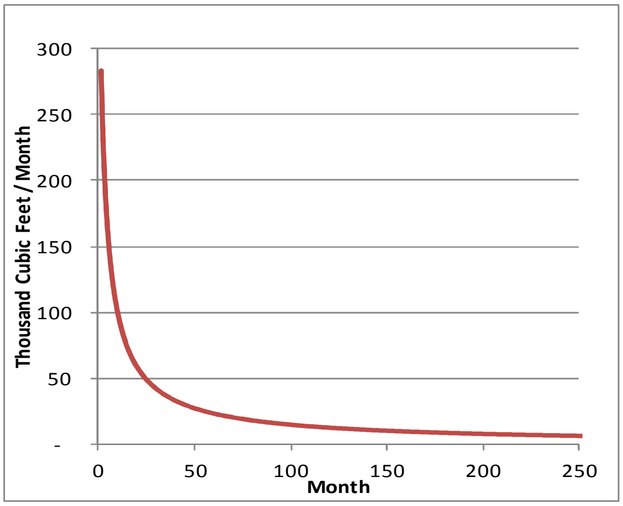
The following four figures depict the extraction rates, or decline curves, for conventional wells over time. Regardless of the well type, extraction rates decline significantly in the first few months and the rates remain relatively flat after 10 to 12 years (120 and 140 months). There is a significant difference in gas production from a gas well and an oil well. For example, while an average gas well produces more than 25,000 thousand cubic feet per day per month in the first month of operation, an average oil well produces less than 3,000 thousand cubic feet per day of gas in the first month.

Figure 15: Gas Production Curve from Gas Wells



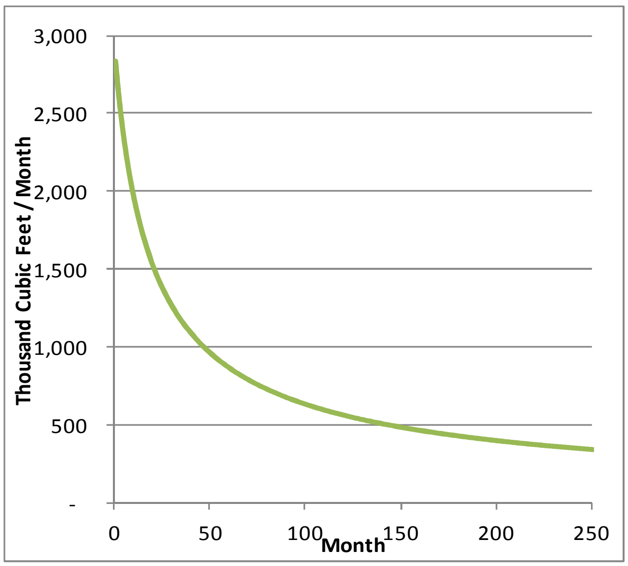
Source: Graphed from Equation 1

Figure 16: Oil Production Curve from Gas Wells



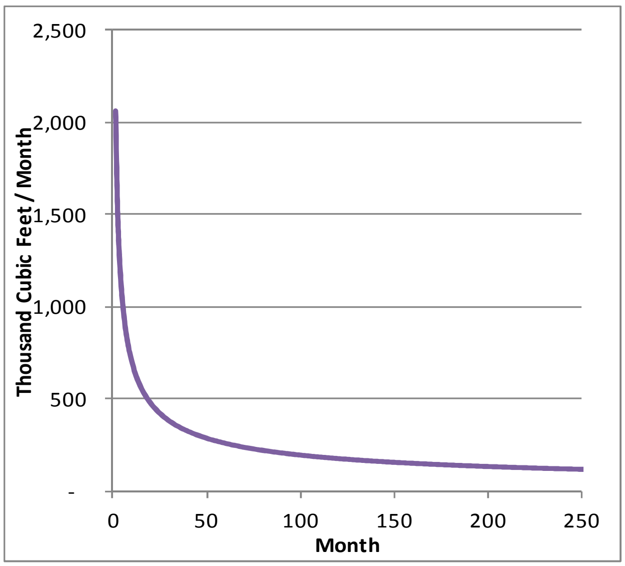
Source: Graphed from Equation 1

Figure 17: Gas Production Curve from Oil Wells



Source: Graphed from Equation 1

Figure 18: Oil Production Curve from Oil Wells



Source: Graphed from Equation 1

5.3 Estimation of Energy Production from Unconventional Mining Sites

Currently, there is not a single site[30] for unconventional oil or gas for energy in the Uinta Basin producing oil from either oil shale or oils sands. Thus, all forecast information regarding currently planned unconventional oil extraction was gathered from documents published by and interviews with potential producers in the Uinta Basin. Unlike those for conventional wells, the extraction rates from unconventional mining sites do not decline over the life span of the sites. Data provided from producers indicated that, once the extraction rate reaches a stable peak, the rate stays constant until the end of the site's lifecycle, which is assumed to be 30 years for the purposes of this forecast. The following subsection provides an overall summary of production forecasts for oil shale and oil sands producers.

5.3.1 Oil Shale

A total of seven oil shale mining sites from six different producers are either planned or under current investor consideration in the Uinta Basin. The first oil shale site is to be built by 2015 with an initial production of 4,000 barrels per day (BPD), which is expected to grow to 25,000 BPD within 7 years. It will produce 25,000 BPD for the rest of the mining site's lifecycle. Overall, the production level for each site ranges from 2,000 BPD to 25,000 BPD, and, at the maximum production level, 131,000 BPD is expected from the Uinta Basin.

Table 15: Oil Shale Sites Starting Year and Extraction Rates Estimates

Producer	Production Start Year	Initial and Final Production Rates (BPD)
Oil shale producer 1 site 1	2020	25,000
Oil shale producer 1 site 2	2025	25,000
Oil shale producer 2	2015	4,000 to 25,000 in 7 Years
Oil shale producer 3	2019	10,000
Oil shale producer 4	2026	10,000 to 20,000 in 3 years
Oil shale producer 5	2021	2,000 or 11,000
Oil shale producer 6	2017	15,000
Total in Uinta Basin		**131,000 BPD at full capacity**

Source: Potential producer interviews.
Note: Barrels per day (BPD). A single oil shale mining site is expected to have 30 operating years.

5.3.2 Oil Sands

A total of six oil sands mining sites from six different producers are either planned or under current investor consideration in the Uinta Basin. Compared to those in oil shale sites, production rates at oil sands sites tend to be lower. The first oil sands site is expected to be built in 2013 with an initial

[30] Development of unconventional energy resources in the Uinta Basin, including oil sands and oil shale, is assumed to occur, in the future, via mining technology. In these scenarios the resource, sand or shale, is extracted via conventional mining technology (open pit or other), and then processed in pits or other means to extract the hydrocarbons. Also, the transportation requirements of such sites are similar to transportation requirements for mines. Thus the terminology and assumptions for transportation requirements for mining are applied for extraction of these resources.

production of 1,250 BPD, which is expected to grow to 5,000 BPD production rate within 4 years. The forecast assumes that, after a mining site reaches full capacity, the production level will stay constant for the rest of the site's lifecycle. Overall, the production level for each site ranges from 250 BPD to 30,000 BPD, and, at the full production level, 70,000 BPD is expected from the Uinta Basin.

Table 16: Oil Sands Sites Starting Year and Extraction Rate Estimates

Producers	Production Start Year	Initial and Final Production Rates (BPD)
Oil sands producer 1	2013	1,250 to 5,000 in 5 years
Oil sands producer 2	2023	2,500 to 5,000 in 4 years
Oil sands producer 3	2013	2,000 to 20,000 in 7 Years
Oil sands producer 4	2015	2,000 to 30,000 in 15 years
Oil sands producer 5	2017	250 or 2,500
Oil sands producer 6	2015	1,200 or 6,400
Total in Uinta Basin		**70,000 BPD at full capacity**

Source: Potential producer interviews.
Note: Barrels per day (BPD). A single oil sands mining site is expected to have 30 operating years.

5.4 Energy Commodity Price Forecast

The energy commodity price forecast acts as both a limit for forecasting new well growth—where the marginal cost of extraction exceeds the price, producers are likely to build fewer wells or mine sites—and provides a valuation for the annual production.

5.4.1 West Texas Intermediate Forecast

WTI prices were forecasted based on official projections made by EIA. Forecasts by the International Energy Administration (IEA), the Interindustry Forecasting Project at the University of Maryland (INFORUM), IHS Global Insight (IHSGI), Purvin & Gertz, and Strategic Energy and Economic Research were also considered and incorporated in the high-low range estimates. These organizations publish forecasts up to 2035, typically with low, mid, and high estimates. After being inflated to 2012 dollar prices, annual WTI prices were forecasted annually from 2013 to 2045. Four periods were picked for ease of review (Table 17).

Table 17: West Texas Intermediate Price per Barrel Forecast (in 2012 dollars)

Crude Oil Price Forecast	Median	Lower 10% Limit	Upper 10% Limit
Current price (in 2012)	$97.04	N/A	N/A
Next 5 years (in 2017)	$105.94	$89.07	$120.75
5 to 10 years (in 2022)	$110.54	$87.54	$131.07
10 to 20 years (in 2035)	$122.80	$105.90	$149.33
Long term (in 2042)	$130.21	$110.74	$163.01

Source: West Texas Intermediate Crude Oil Price and median forecasts based on Annual Energy Outlook 2012, U.S. Energy Information Administration; with additional data from International Energy Administration, Interindustry Forecasting Project at the University of Maryland, IHS Global Insight, Inc., Purvin & Gertz, and Strategic Energy and Economic Research, Inc.

5.4.2 Waxy Crude Price Forecast

The Uinta Basin does not produce crude oil quality that is equivalent to that of WTI. Instead, the conventional crude oil resource in the Uinta Basin is often called waxy crude because its high paraffin content causes it to solidify at a temperature of approximately 100 degrees Fahrenheit. Because of its quality relative to WTI, there is a discount in market price for the Uinta Basin's waxy crude. The available data and estimate for these ratios are presented in Table 18.

Table 18: Waxy Crude Wellhead Discount Relative to WTI

Waxy Crude Price Discount (%)	Median	Lower 10% Limit	Upper 10% Limit
Current discount (in 2012)	15%	–	–
Forecast period discount	15%	10%	20%

Source: Chevron Crude Oil Marketing Posted Pricing, producer interviews

Because there was no analysis of future waxy crude prices, the forecast price per barrel was derived by applying the above discount ratio to the WTI price forecast. Table 19 below summarizes forecasted prices per barrel of waxy crude. For valuing both conventional and unconventional oil product in the Uinta Basin, the same prices per barrel are applied.

Table 19: Waxy Crude Price per Barrel (in 2012 dollars)

Waxy Crude Price Forecasts	Median	Lower 10% Limit	Upper 10% Limit
Current price (in 2012)	$82.48	–	–
Next 5 years (in 2017)	$90.10	$75.70	$102.60
5 to 10 years (in 2022)	$94.00	$74.40	$111.40
10 to 20 years (in 2035)	$104.40	$90.00	$127.00
Long term (in 2042)	$110.70	$94.10	$138.60

5.4.3 Natural Gas Price Forecast

Of the natural gas consumed in the U.S. in 2011, about 94% was produced domestically. Thus, the supply of natural gas is not as dependent on foreign producers as is the supply of crude oil, and the delivery system is less subject to international market fluctuations. The availability of large quantities of shale gas should enable the U.S. to consume a predominantly domestic supply of gas for many years and potentially produce more natural gas than it consumes.

The EIA's Annual Energy Outlook 2012 projects U.S. natural gas production to increase from 21.6 trillion cubic feet in 2010 to 27.9 trillion cubic feet in 2035, a 29% increase. Almost all of this increase is due to projected growth in shale gas production, which EIA forecasts to grow from 5.0 trillion cubic feet in 2010 to 13.6 trillion cubic feet in 2035.

The emergence of shale gas production has been one key driver of the downward pressure in domestic natural gas prices. Increasingly, the U.S. is seen to be a potential net exporter of natural gas in the form of LNG. Currently, no fewer than 15 export terminal facilities have been identified or proposed to the Federal Energy Regulatory Commission (FERC).

Henry Hub natural gas prices are forecasted by EIA with low, mid, and high estimates from 2012 to 2035. EIA provides annualized forecasts, but we have summarized the forecast by period for ease of review in Table 20 below.

Table 20: Henry Hub Natural Gas Price per Million British Thermal Units Forecast (in 2012 dollars)

Natural Gas Price Forecast ($ per Million British Thermal Units)	Median	Lower 10% Limit	Upper 10% Limit
Price in 2012	$2.61	–	–
Next 5 years (in 2017)	$4.79	$3.83	$5.99
5 to 10 years (in 2022)	$5.50	$4.40	$6.87
Long term (in 2035)	$5.92	$4.74	$7.40

Source: Based on Henry Hub Natural Gas Price at Louisiana, U.S. Energy Information Administration.
Note: 2012 Henry Hub Average price is $2.61, but the average of the last 3 months is $3.50.

Due to the lack of an official projection for Utah wellhead natural gas prices, the forecasts were derived by applying a discount ratio to Henry Hub natural price forecasts. Figure 19 shows historical real price differentials between Henry Hub and Utah wellhead natural gas prices. Regression analyses reveal that natural gas wellhead prices in Utah are on average lower by 16% to 29%, with 95% confidence, in comparison to Henry Hub prices.[31]

Figure 19: Utah Wellhead Prices and Henry Hub Natural Gas Prices, 1997 to 2011

Source: U.S. Energy information Administration

[31] Based on analysis of historical prices of Utah wellhead and Henry Hub from 1997 to 2011

Table 21: Discount of Utah Wellhead Prices Relative to Henry Hub Prices

Wellhead Natural Gas Price Discount Relative to Henry Hub (%)	Median	Lower 10% Limit	Upper 10% Limit
Current discount (in 2012)	22%	–	–
Next 5 years (in 2017)	22%	16%	29%
5 to 10 years (in 2022)	22%	16%	29%
Long term (in 2040)	22%	16%	29%

Source: Utah well head natural gas prices from U.S. Energy Information Administration Henry Hub prices

Table 22 below summarizes forecasted prices for Utah natural gas at the wellhead. The discount rate listed in Table 21 above is applied on Henry Hub natural gas prices (Table 20 above) to derive forecasts for Utah wellhead prices.

Table 22: Utah Wellhead Natural Gas Prices per Million British Thermal Units Forecast (in 2012 dollars)

Utah Wellhead Prices	Median	Lower 10% Limit	Upper 10% Limit
Price in 2012	$2.19	–	–
Next 5 years (in 2017)	$4.00	$3.20	$5.00
5 to 10 years (in 2022)	$4.60	$3.70	$5.80
Long term (in 2035)	$5.00	$4.00	$6.20

5.4.4 Natural Gas Liquids Price Forecast

Certain NGLs, such as condensate, are a byproduct of oil and gas extraction and are valued. NGLs can return high prices in the current market, which some producers indicate are keeping natural gas extraction activities financially afloat. The forecast of NGL aggregate prices was not conducted separately. Instead, based on producer input, a discount to the WTI forecast was used to derive the NGL prices. Table 23 shows an average discount rate is 30% with a low and high at 20% and 40%, respectively. These rates were applied to WTI forecast prices to compute NGL prices. Table 24 shows the computed NGL price forecasts.

Table 23: Discount of Natural Gas Liquids Relative to WTI

Natural Gas Liquids Price Discount Relative to West Texas Intermediate (%)	Median	Lower 10% Limit	Upper 10% Limit
Current discount (in 2012)	30%	–	–
Next 5 years (in 2017)	30%	20%	40%
5 to 10 years (in 2022)	30%	20%	40%
Long term (in 2040)	30%	20%	40%

Source: Uinta Basin producer interviews

Table 24: Natural Gas Liquids Price Forecasts

Natural Gas Liquids Price	Median	Lower 10% Limit	Upper 10% Limit
Current price (in 2012)	$67.83	—	—
Next 5 years (in 2017)	$74.20	$62.40	$84.50
5 to 10 years (in 2022)	$77.40	$61.30	$91.80
Long term (in 2040)	$86.00	$74.10	$104.50

5.5 Marginal Cost of Production

The marginal cost of production will impact producers' decisions on building wells or mining sites. Where the marginal cost plus an assumed profit requirement is below the forecast commodity price, exploration and drilling are assumed to rise; where the marginal cost exceeds the forecast market price, drilling is assumed to decline.[32]

5.5.1 Marginal Cost of Producing Conventional Resources

The two tables below provide both the capital and marginal costs of producing conventional resources. The cost of building a well ranges from $0.9 million to $2.8 million in the Uinta Basin depending on the terrain and the well complexity (degree of directional drilling). Table 25 provides the estimate of the capital cost of building a single well. Table 26 provides an overall marginal cost of production per unit of output.

Table 25: Capital Cost of Building a Conventional Well

Estimate	Value	Source
Conventional oil well, Newfield, Uinta Basin	$0.93 million[a]	Newfield, Uinta Basin/Greater Monument Butte Area
Conventional well, across Uinta Basin producers	$0.4 million (low), $0.8 million (mid), $1.5 million (high)	"Estimates of the Marginal Cost of Oil and Gas Production in the Uinta Basin," Institute for Clean and Secure Energy, University of Utah

Note: 2012 U.S. dollars.
[a] For conventional vertical wells with limited directional drilling. Horizontal well estimates are $2.6 million to $2.8 million.

Table 26: Marginal Cost of Production per Unit Output

Estimate	Value	Source
Conventional oil well, across Uinta Basin producers	$26 to $53 per barrel of oil	"Estimates of the Marginal Cost of Oil and Gas Production in the Uinta Basin" Institute for Clean and Secure Energy, University of Utah
Conventional gas well, across Uinta Basin producers	$2.80 to $5.60 per thousand cubic feet of gas	"Estimates of the Marginal Cost of Oil and Gas Production in the Uinta Basin" Institute for Clean and Secure Energy, University of Utah

Note: 2012 U.S. dollars.

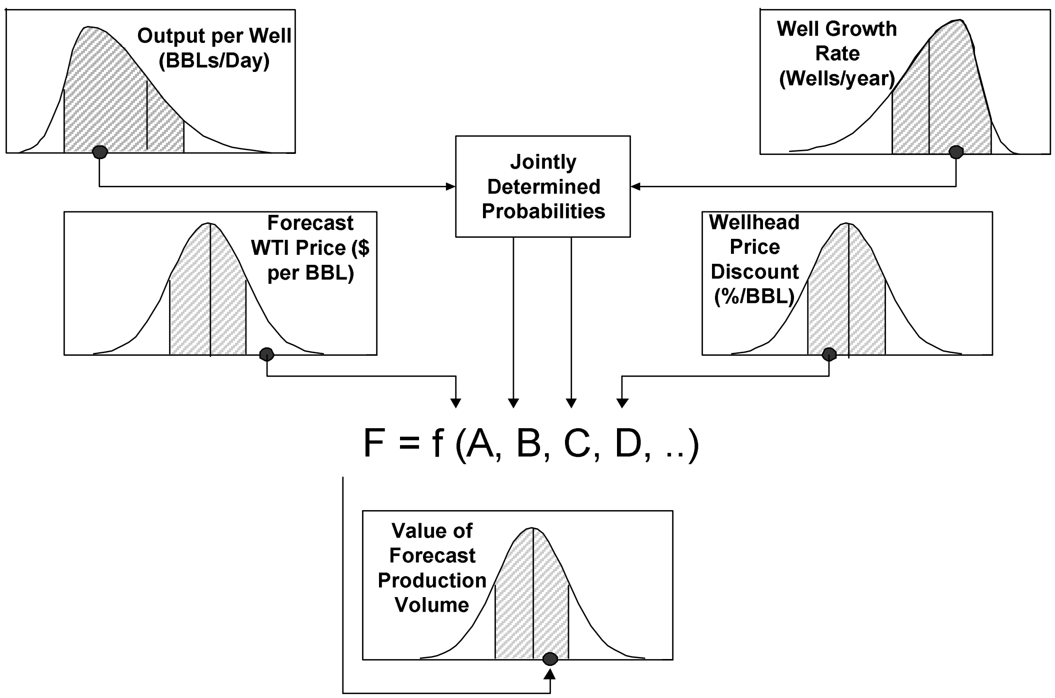
[32] Marginal revenue and marginal cost effects are modeled for conventional resources only, risks related to economic feasibility of unconventional resource extraction are addressed through the risk analysis.

5.6 Application of Risk Analysis

Risk analysis needs to be performed in this step because a total maximum time-phased production forecast carries uncertainties. Uncertainties exist in forecasts of both conventional and unconventional extraction rates; the future prices of waxy crudes, natural gas, and NGL, and the extraction rates of energy commodities. Sections 5.1 to 5.5 list key forecast variables with low, mid, and high values. Thus, the process of forecasting total production volume and value for the next 30 years needs to incorporate these uncertainties.

Using Monte Carlo simulation techniques, each variable was allowed to vary simultaneously according to its associated probability distribution. Final probability distributions represent a combination of expected outcomes and their likelihood. See Figure 20 for an illustration of this process. For this step, 10,000 iterations were performed.

Figure 20: Combining Probability Distributions *(for Illustration Only)*



5.7 Findings

Figure 21 presents the maximum, time-phased production in dollar value at the 10th, 50th and 90th percentile values.[33] The figure represents combined total energy (crude oil, oil shale, oil sands, natural gas, and NGLs) dollar values. Our forecast projects that, at a maximum, energy values in the Uinta Basin will double the current level by 2017[34], mostly propelled by the additional extraction of unconventional

[33] The Monte Carlo simulation results in estimates at each percentile; for ease comprehension results are displayed at the low (10th percentile), median (50th percentile), and high (90th percentile) only.

[34] Readers should note, this forecast represents the maximum potential, but does not account for either non-transportation risks or capacity limitations that will likely limit output. Non-transportation risk effects are

energy resources. By the end of the analysis period in 2042, the forecasted median energy value surpasses $14 billion in 2012 U.S. dollars. Readers should note that this represents the maximum resource extraction potential for the study period. The transportation-unconstrained forecast is equal-to or less-than the maximum forecast (see section 6), because it incorporates additional production risks, particularly with respect to unconventional production.

Figure 21: Maximum Time-Phased Production Forecast – Extraction Forecast, All Commodities in Value ($ Million)

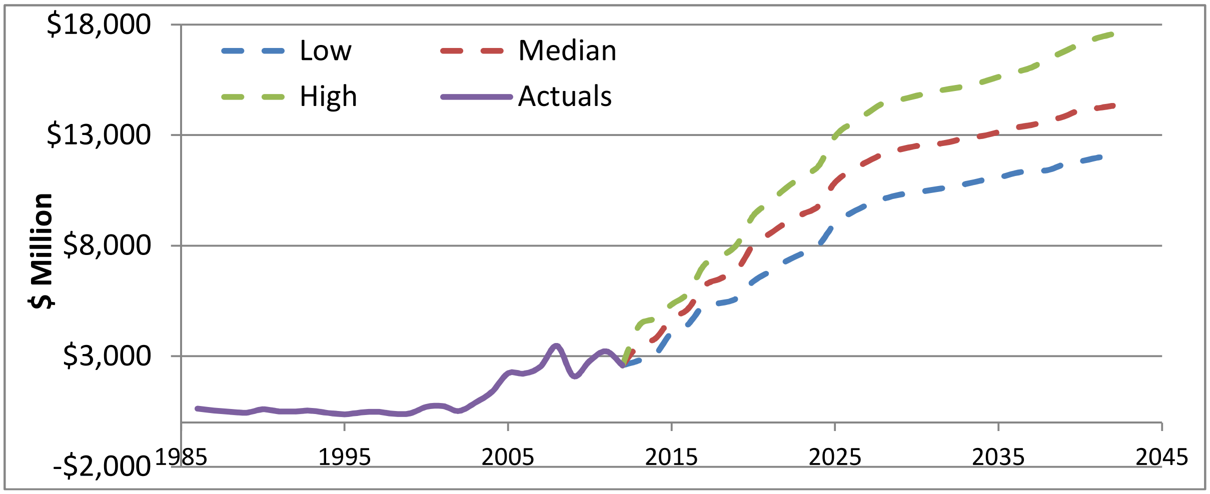
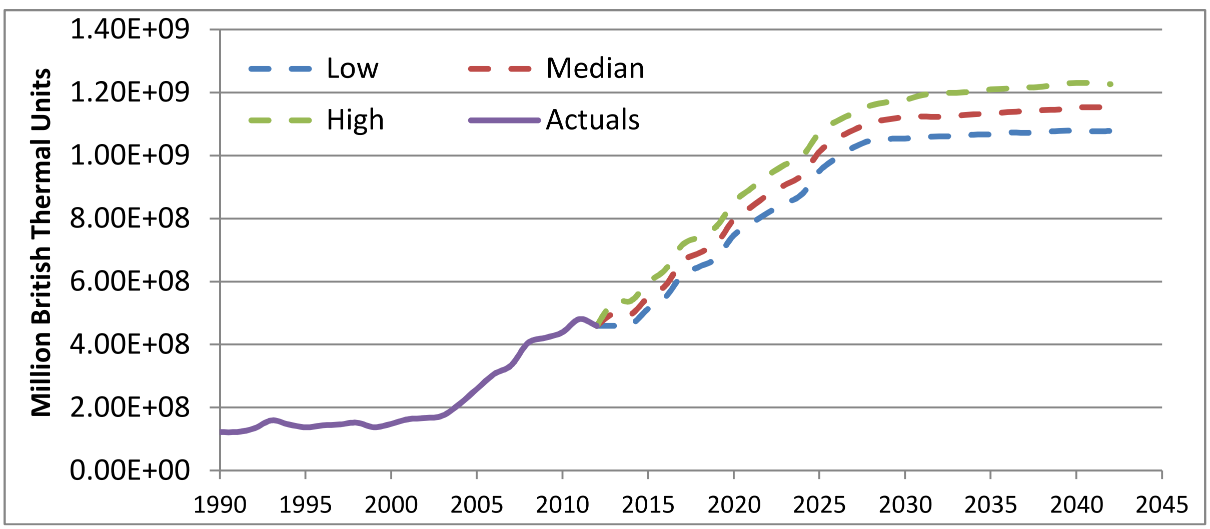


Figure 22 presents the same forecast in terms of MMBtu (million British thermal units). The maximum forecast indicates a rapid expansion of output, from a current 450 million MMBTU (million British thermal units) today to about 1.2 billion MMBtu (million British thermal units) by 2042.

Figure 22: Maximum Time-Phased Production Forecast – Extraction Forecast, All Commodities in Million British Thermal Units



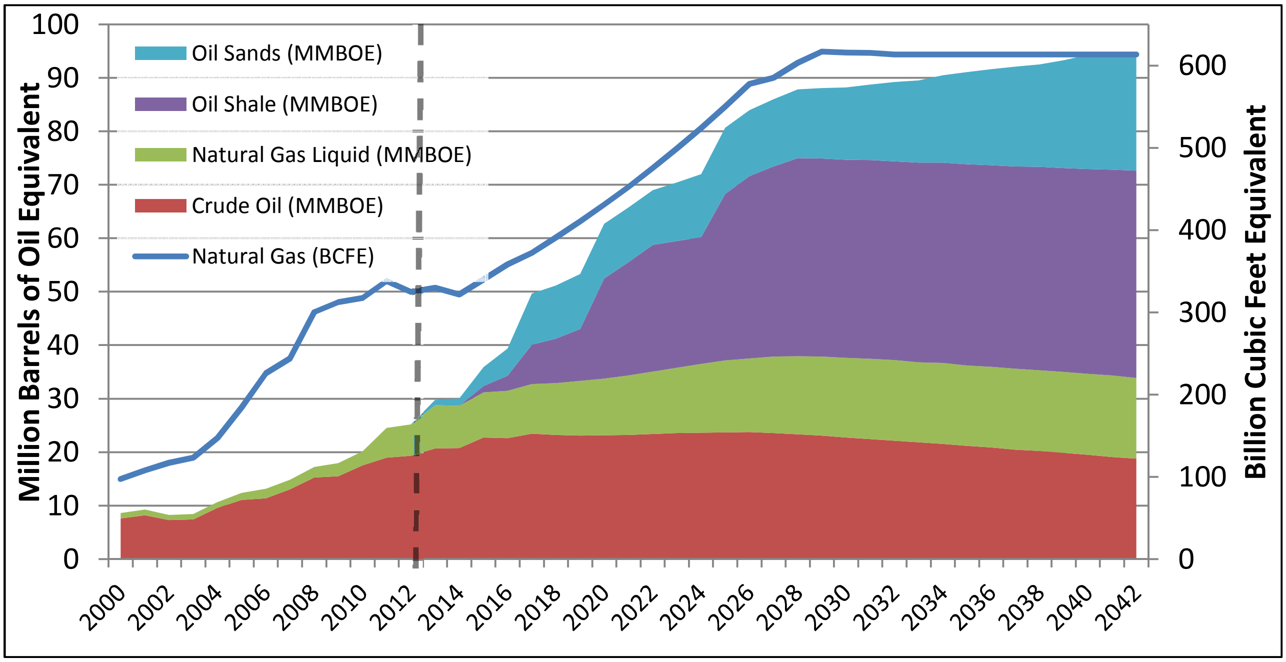
addressed in the unconstrained forecast, Section 6, and transportation capacity limitation are addressed in the constrained forecast, Section 7.

Figure 23 presents the maximum, time-phased production by commodity types at the median value. Oil sands, oil shale, NGL, and conventional oil are expressed in million barrels equivalent on the left axis. Natural gas is presented in billion cubic feet equivalent on the right axis.

Unconventional oil resources are extracted from 2015, and significant production is expected by 2020. By 2025, more oil from unconventional resources is expected than from conventional wells. At the end of the analysis period (2042), the Uinta Basin is expected to produce about 90 million barrels of combined oil and NGLs per year.

The maximum production of natural gas increases rapidly until 2028, at which point the production rate remains relatively flat at around 600 BCF per year.

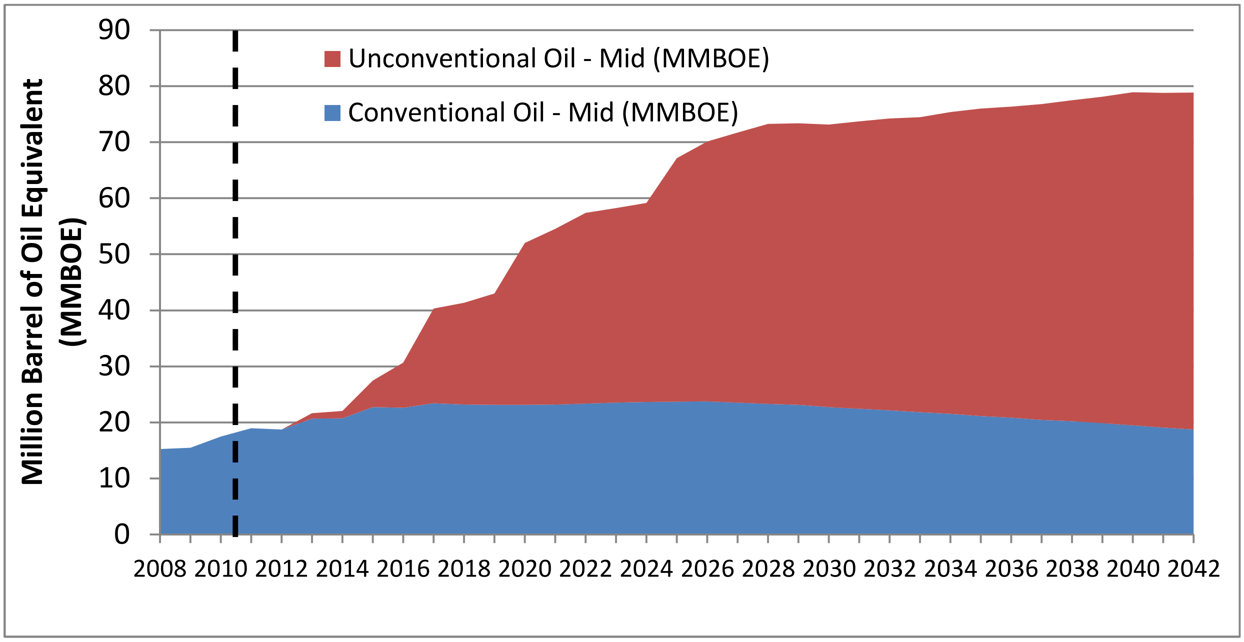
Figure 23: Maximum Time-Phased Production Forecast – Forecast by Commodity Type at Median



Note: Million barrels of oil equivalent (MMBOE). Billion cubit feet equivalent (BCFE). All values on a per year basis; estimates are for the Uinta Basin.

Figure 24 shows the growing share of unconventional oil in the Uinta Basin throughout the forecast. While annual conventional oil production decreases after its peak in 2016, annual unconventional oil production continues to grow, reaching more than 60 million barrels per year by 2042.

Figure 24: Maximum Time-Phased Production Forecast – Growing Role of Unconventional Oil (million barrels of oil equivalent)



Note: Million barrels of oil equivalent (MMBOE). All values on a per year basis; estimates are for the Uinta Basin.

Estimation of the maximum, time-phased production forecasts is the first step toward our transportation-unconstrained forecast. It represents the maximum limit of the forecast, which is then revised based on the assessment of certain non-transportation constraints and risks. This step does not consider any obstacles during the analysis period, but takes only forecast uncertainties into account. The next step, the transportation-unconstrained forecast, is a risk-adjusted time-phase production forecast. The transportation-unconstrained forecast takes event risks—such as environmental, regulatory, geological, technological, market, and capacity—into account.

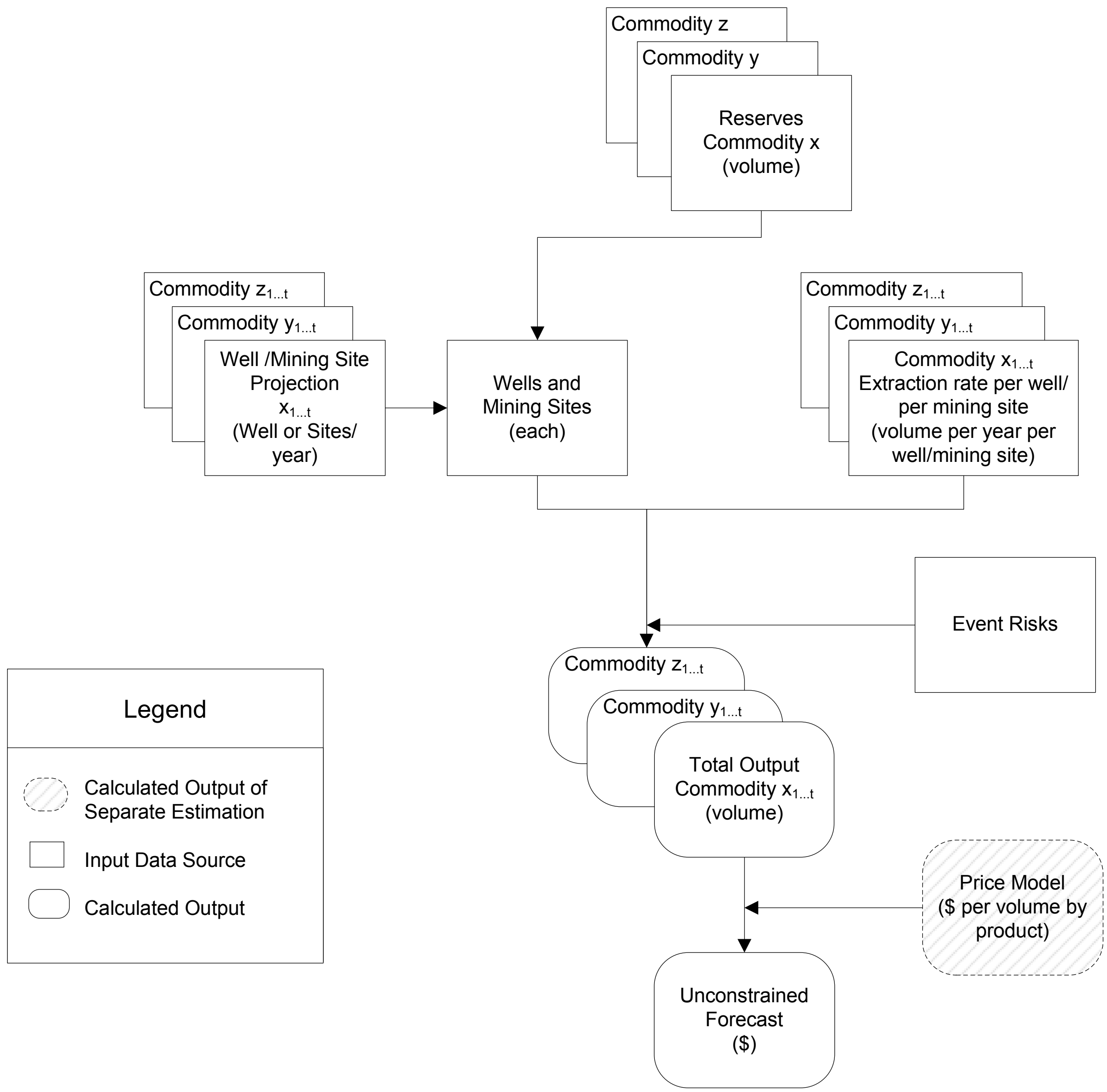
6 Unconstrained Forecast

The unconstrained forecast is the risk-adjustment of the maximum time-phased production forecast model. The maximum forecast incorporates forecast variable uncertainties, but does not include the risks discussed in this section. The unconstrained forecast is not constrained by transportation capacity limitations, but does reflect other market and production risks.

6.1 Unconstrained Forecast Approach

Figure 25 below illustrates the structure and logic of the transportation-unconstrained forecast approach. Input data sources (including commodities, resource and reserve estimates in the Uinta Basin, number of wells and mining sites, extraction rates, etc.) lead to the estimation of a production forecast. The difference between this and the maximum time-phased forecast is that the output is constrained by event risks, described in Section 6.2. A preliminary estimate of the transportation-unconstrained output volume forecast was prepared by commodity, by year, constrained by available resources. This output volume is converted into a value forecast based on a separate commodity price forecast.

Figure 25: Structure and Logic of Unconstrained Forecast Model



6.2 Risk Factors

As with the maximum, time-phased forecast, the analysis spans 30 years, and involves forecasts of multiple key variables—energy commodity prices, number of oil and gas wells, number of mining sites, and others. In addition, there are many probable occurrences that could affect production levels in the Uinta Basin. These are defined as event risks, which are discussed in this section.

Event risks are specific occurrences that could change the conditions driving the forecast. Unlike uncertainties, which are forecast variables whose future values cannot be exactly known, event risks are conditions that might or might not happen at some point during the forecast period. It is uncertain how likely these events are to occur or the level of impact they might have on the forecast. But, ultimately, the event risk either comes to pass or it does not.[35]

These risks include market forces that tend to make certain types of production more or less attractive, technological changes that might make new extraction techniques possible, limitations imposed by environmental and other regulatory issues, and producer implementation capacity issues that aggregate various pressures faced by producers that might make them more or less likely to implement current plans. These risks were developed and quantified in conjunction with stakeholders, study partners, and industry experts. The end result is a conservative forecast of expected production, given the maximum production forecast and risks to the fulfillment of that forecast, but assuming that transportation capacity is not an issue that might limit production outcomes.

The risk register captures event risks that could affect the forecast. The register in Table 27 captures a variety of event risk details:

1. **Risk ID:** a field used to assign a unique identification (ID) to each event risk for modeling purposes.
2. **Risk category:** the type of event—categories included are regulatory risks, technology risks, capacity risks, environmental risks, market risks, and price risks.
3. **Threat or opportunity event:** a description of the specific risk being considered.
4. **Probability of event:** the assessed likelihood that the specific risk will come to pass.
5. **Directly impacted variable:** the forecast element that the risk might impact—for example, a lower-than-expected recovery rate for oil from oil shale would affect the expected output per mine per year.
6. **Units for impact:** typically percentage or value.
7. **Magnitude of impact:** the effect of the risk if it does happen—typically specified as a low, mid, and high estimate.

[35] This study relies on these definitions of "risk" (an event with a given probability of occurrence) and "uncertainty" (an uncertain future value of a known forecast element), but acknowledges that these are not the classically accepted formal definitions (see F.H. Knight, Risk, Uncertainty and Profit, 1921, Hart, Schaffner & Marx).

Table 27: Risk Register

Risk ID	Risk Category	Threat or Opportunity Event	Probability of Event	Directly Impacted Variable(s)	Units for Impact	Magnitude of Impacts			Notes
						Low	Mid	High	
1	Environmental Risks	Pipeline breach caused by natural disaster	1%	Total gas output volume	Months delay	1.00	6.00	12.00	Risk would temporarily affect gas output. Risk is repeated in each year of forecast.
2	Technology Risks	Transportation disruption impacts supply of Uinta Basin energy to market	10%	Transportation cost per unit output	Dollars per output unit	5%	10%	15%	Risk would result in temporary increase in marginal cost per output Risk is repeated in each year of forecast. Average time frame of impact would be 1 to 3 months.
3	Technology Risks	Change in extraction technology resulting in lower costs	30%	Marginal cost per unit output	Dollars per output unit	−10%	−20%	−30%	Risk would result in growth of wells built. Risk is repeated in each year of forecast.
4	Regulatory Risks	Temporary ban on hydraulic fracturing in major North American market	1%	Output per well	Volume output	0%	−5%	−10%	Risk would temporarily reduce per well output. Risk is repeated in each year of forecast. Would halt new drillings (not affect existing ones) can correlate with other risks.
5	Regulatory Risks	Changes in offshore drilling legislation	10%	Well construction rate	% of wells built	−20%	0%	20%	Risk could result in either growth or decline in wells built. Risk is repeated in each year of forecast.
6	Regulatory Risks	Increases in environmental and regulatory constraints	10%	Well construction rate	Wells built	−40%	−25%	−10%	Risk would result in decline of wells built. Risk is repeated in each year of forecast.
7	Regulatory Risks	Increases in environmental and regulatory constraints on oil sands	20%	Oil sands facility construction timing	Years delay	0.50	1.00	2.00	Risk would result in delay of site construction.

Risk ID	Risk Category	Threat or Opportunity Event	Probability of Event	Directly Impacted Variable(s)	Units for Impact	Magnitude of Impacts			Notes
						Low	Mid	High	
8	Regulatory Risks	Increases in environmental and regulatory constraints on oil shale	20%	Shale oil facility construction timing	Years delay	0.50	1.00	2.00	Risk would result in delay of facility construction.
9	Regulatory Risks	Delays in permitting impacts start of energy extraction	50%	Production start – new wells	New well built	0%	–20%	–35%	Risk would result in decline of wells built. Risk is repeated in each year of forecast. Risk is slightly higher for oil sands and shale.
10	Regulatory Risks	Additional requirements for permitting with hydro-fracking on U.S. Bureau of Land Management/tribal land increases costs of drilling and completion	50%	Marginal cost of production	Dollars per output unit	5%	10%	25%	Risk would result in increase in marginal cost of production for oil and gas.
11	Regulatory Risks	New regulations on pipelines increase transport costs	5%	Marginal costs of production by increase in transportation cost	Dollars per output unit	2%	5%	8%	Risk would result in increase in marginal cost of production for gas due to increase in transportation cost in pipeline.
12	Market Risks	Volatility in crude oil market price	50%	Market price	Dollars per output unit	–20%	0%	20%	Risk could result in either higher or lower prices realized. Risk is repeated in each year of forecast.
13	Market Risks	Market constraints on oil sands	25%	Oil sands construction timing	Years delay	0.00	2.00	4.00	Market result would result in delay of site construction.
14	Market Risks	Market constraints on oil sands	25%	Oil sands construction timing	Years delay	0.00	2.00	4.00	Market result would result in delay of facility construction.

Risk ID	Risk Category	Threat or Opportunity Event	Probability of Event	Directly Impacted Variable(s)	Units for Impact	Magnitude of Impacts			Notes
						Low	Mid	High	
15	Capacity Risks	Increased production costs due to resource constraints (water, sand, labor, etc.)	10%	Marginal cost per unit output	Dollars per output unit	10%	15%	20%	Risk would result in decline of wells built. Risk is repeated in each year of forecast
16	Capacity Risks	There is some probability that a lower number of gas conventional wells will be built that year	25%	New development of gas wells	New gas well built	0%	25%	50%	Risk would result in decline of new gas wells built. Assume that there is 25% probability chance that 0% to 50% of gas conventional wells will not be built that year.
17	Capacity Risks	There is some probability that a lower number of oil conventional wells will be built that year	25%	New development of oil wells	New oil well built	0%	25%	50%	Risk would result in decline in new oil wells built. Assume that there is 25% probability chance that 0% to 50% of oil conventional wells will not be built that year.
18	Capacity Risks	The probability that a specific oil shale mining site will not be built	40%	Oil shale mining site	New oil shale mining site built	100%	100%	100%	There are seven planned oil shale mining sites. Each site has an independent probability of 40% that the site will not be built
19	Capacity Risks	The probability that a specific oil sands mining site will not be built	40%	Oil sands mining site	New oil sands mining site built	100%	100%	100%	There are six planned oil sands mining sites. Each site has an independent probability of 40% that the site will not be built.

Source: UBETS Stakeholders' Input.

6.3 Risk Analysis

As with the maximum time-phased forecasts (Section 0), the risk analysis approach incorporates estimated uncertainties in key forecast variables to produce ranges of possible outcomes. Risk analysis needs to be performed in this step because the unconstrained forecast includes not only forecast uncertainties but also event risks. Uncertainties exist in forecasts of both conventional and unconventional extraction rates, future prices of waxy crudes, natural gas, and NGLs, and extraction rates of energy commodities as shown in Sections 5.1 to 5.4. The unconstrained forecast also incorporates event risks, which are summarized in Table 27.

A Monte Carlo simulation was conducted to produce the unconstrained forecast. Each variable and forecasting coefficient was varied simultaneously according to its associated probability distribution. The forecast model is designed such that event risks occur in a certain percentage of iterations, based on their defined probability of occurrence. Event risks are independent of each other and overlap or separation of occurrence between risks across iterations is a randomized product of the Monte Carlo simulation. Final probability distributions represent a combination of expected outcomes and their likelihood. For this step, the forecast model was iterated 10,000 times.[36]

6.4 Findings

In comparison with maximum time-phased production forecasts, the transportation-unconstrained production forecast is somewhat lower, as expected. Risks listed in Table 27 are mostly negative shocks—when they come to pass, they negatively affect energy commodity production.

Figure 26 presents the transportation-unconstrained production forecast by dollar value. After factoring the 19 identified event risks into the forecast, additional extraction of unconventional energy commodities still propels the overall production to about double of current levels by 2020, about 3 to 4 years later than in the case of the maximum time-phased forecast. By the end of the analysis period, by 2042, the total forecasted energy value at the median value is expected to surpass $12 billion in 2012 U.S. dollars.

[36] See Figure 20 for a diagrammatic illustration of the simulation process.

Figure 26: Unconstrained Production Forecast – Extraction Forecast in Value ($ Million)

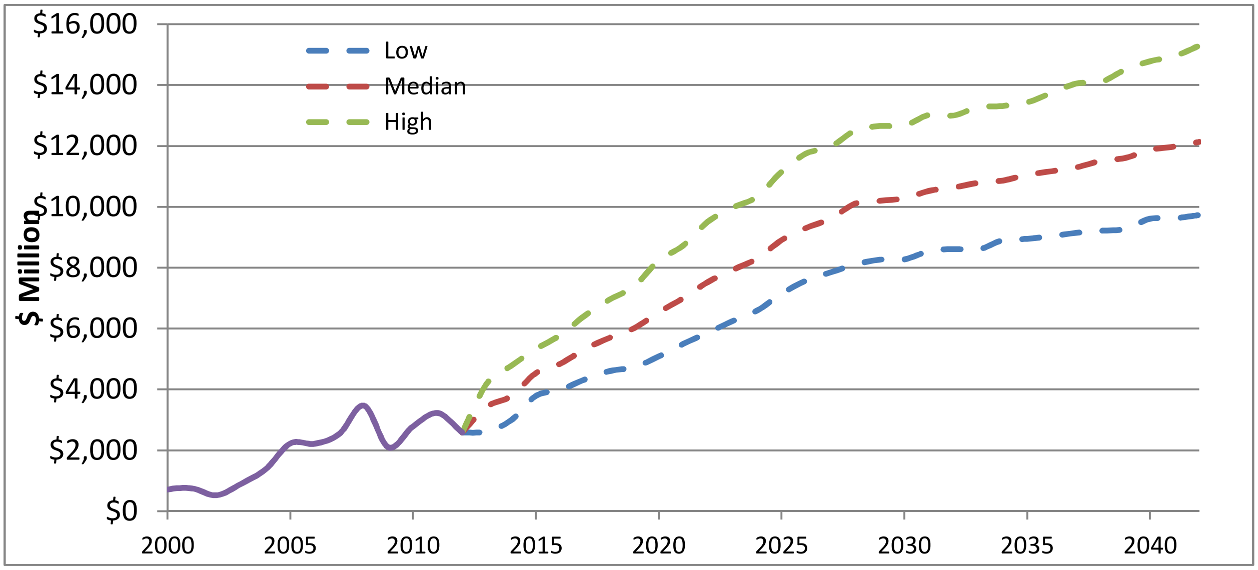


Figure 27 presents actual and forecasts of total energy units produced in the Uinta Basin from 2000 to 2042. By 2042, assuming no transportation constraints, the Uinta Basin is expected to produce about 1 billion MMBtu (million British thermal units), slightly lower than the 1.2 billion MMBtu (million British thermal units) projected under the maximum time-phased production forecast.

Figure 27: Transportation-Unconstrained Production Forecast (Million British Thermal Units)

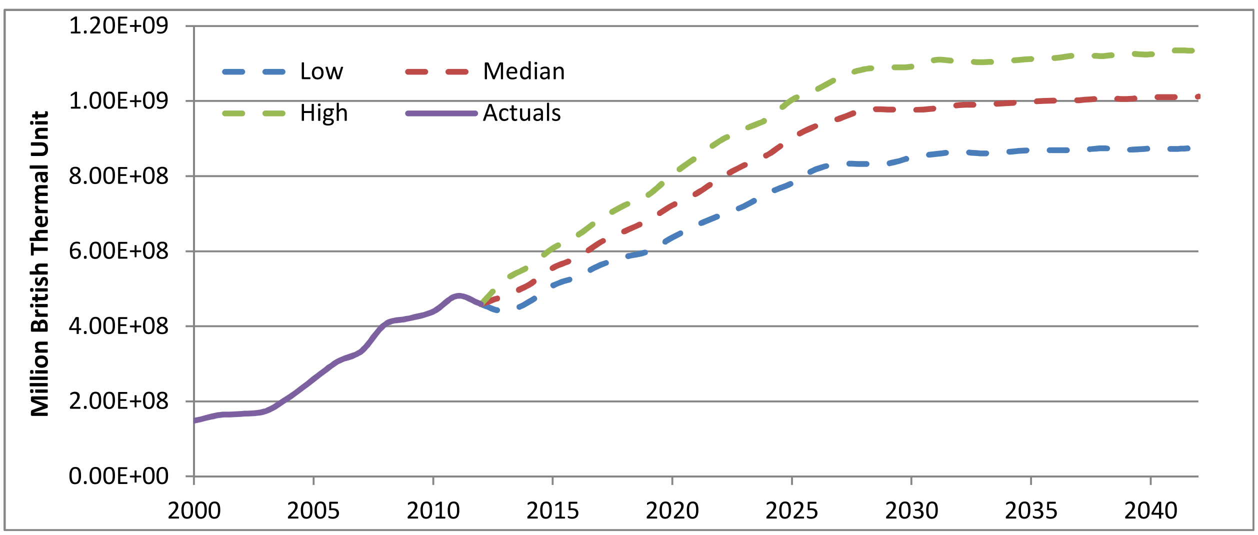
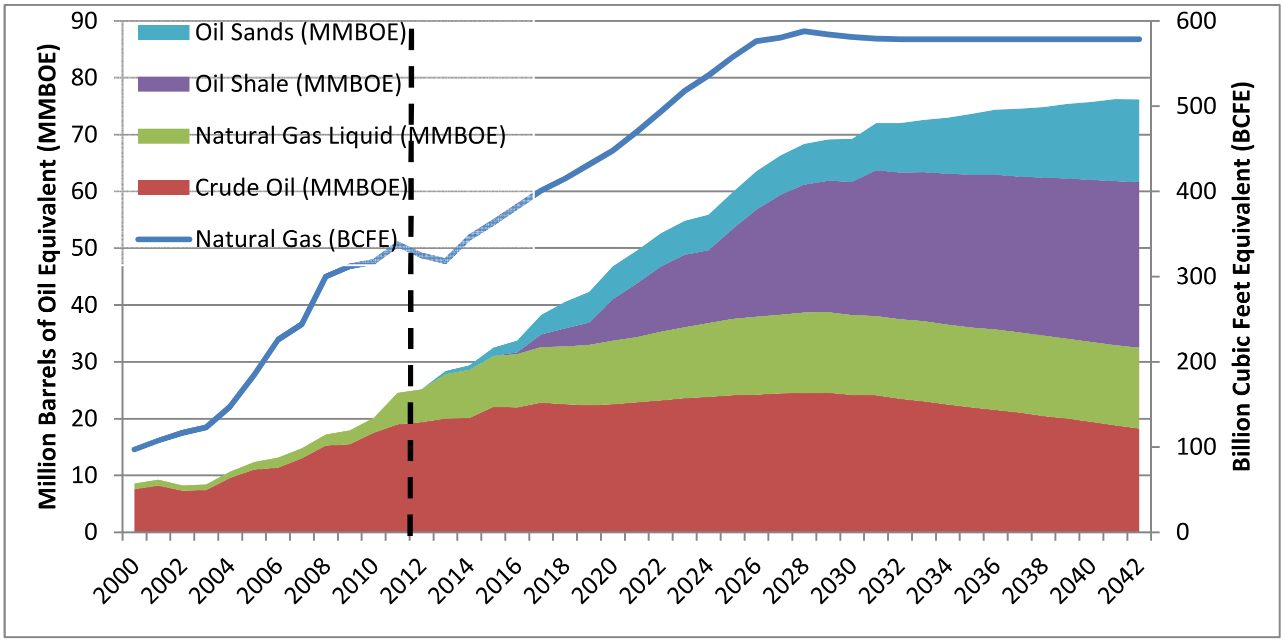


Figure 28 presents the transportation-unconstrained production forecast by commodity type at the median value. Oil sands, oil shale, NGL, and conventional oil are expressed in million barrels of oil equivalent on the left axis. Natural gas is in billion cubic feet equivalent on the right axis.

Extraction of unconventional oil resources begins in 2013, and significant amounts are in production by 2020. By 2035, more crude oil from unconventional resources is expected than from conventional wells. At the end of the analysis period (2042), the Uinta Basin is expected to produce about 76 million barrels of combined oil and NGL. The production of natural gas increases rapidly until 2028, after which production remains relatively flat at around 600 billion cubic feet per year.

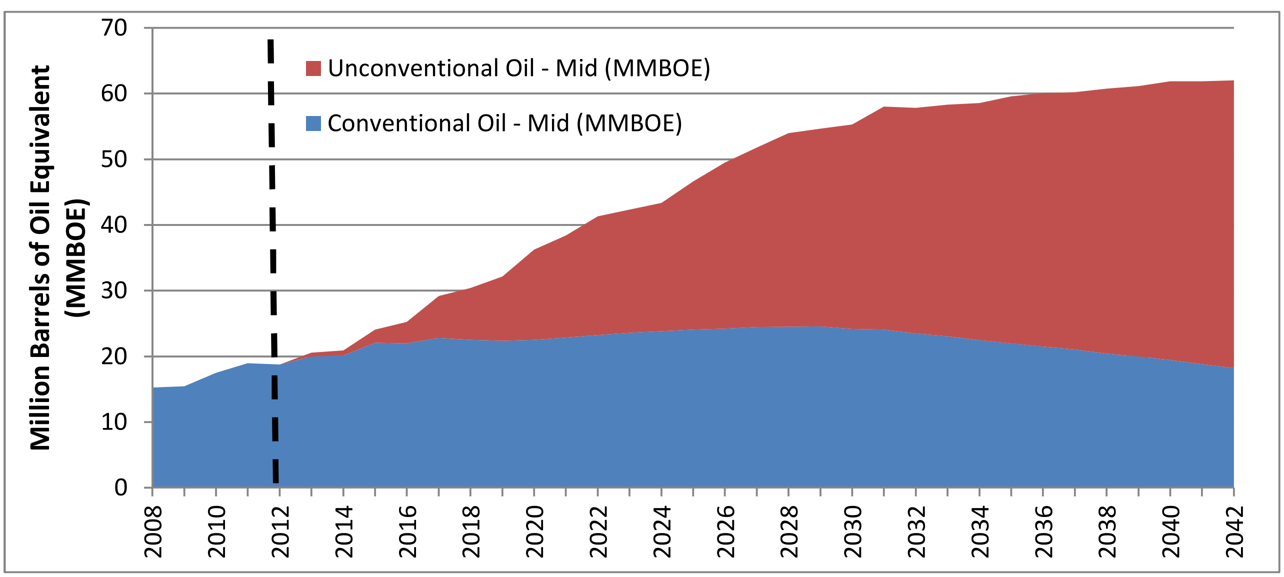
Figure 28: Transportation-Unconstrained Production Forecast – Forecast by Commodity Type at Median



Note: Million barrels of oil equivalent (MMBOE). Billion cubit feet equivalent (BCFE). All values on a per year basis; estimates are for the Uinta Basin.

Figure 29 shows the growing share of unconventional oil in the transportation-unconstrained forecast. The unconventional production estimates are based on data provided by producers currently planning or considering production along with the risks identified above. While the unconstrained forecast shows conventional oil production as likely to grow over the next 30 years, unconventional oil production is likely to eclipse conventional production and reach close to 40 million barrels per year by 2042. The production level in the unconstrained forecast is lower than the maximum, time-phased forecast due to uncertainty regarding the timing and likelihood that individual unconventional mining sites are built.

Figure 29: Unconstrained Production Forecast – Growing Role of Unconventional Oil (million barrels of oil equivalent)



Note: Million barrels of oil equivalent (MMBOE). All values on a per year basis; estimates are for the Uinta Basin.

Figure 30 and Figure 31 illustrate the effects of the application of event risks to the unconstrained forecast in dollar terms and energy content terms, respectively. The present value of the 30 year maximum forecast is about $189 billion while the present value of the unconstrained forecast is about $160 billion. The addition of event risks, then, represents a 15% decrease in the net value of the total forecast. Similarly, in energy content terms, the 30 year sum of the maximum forecast is 28.8 billion MMBtu (million British thermal units) compared to 25.8 billion MMBtu (million British thermal units) for the unconstrained forecast, a net reduction of 10%.

Figure 30: Comparison of Maximum and Unconstrained Forecasts ($ Million)

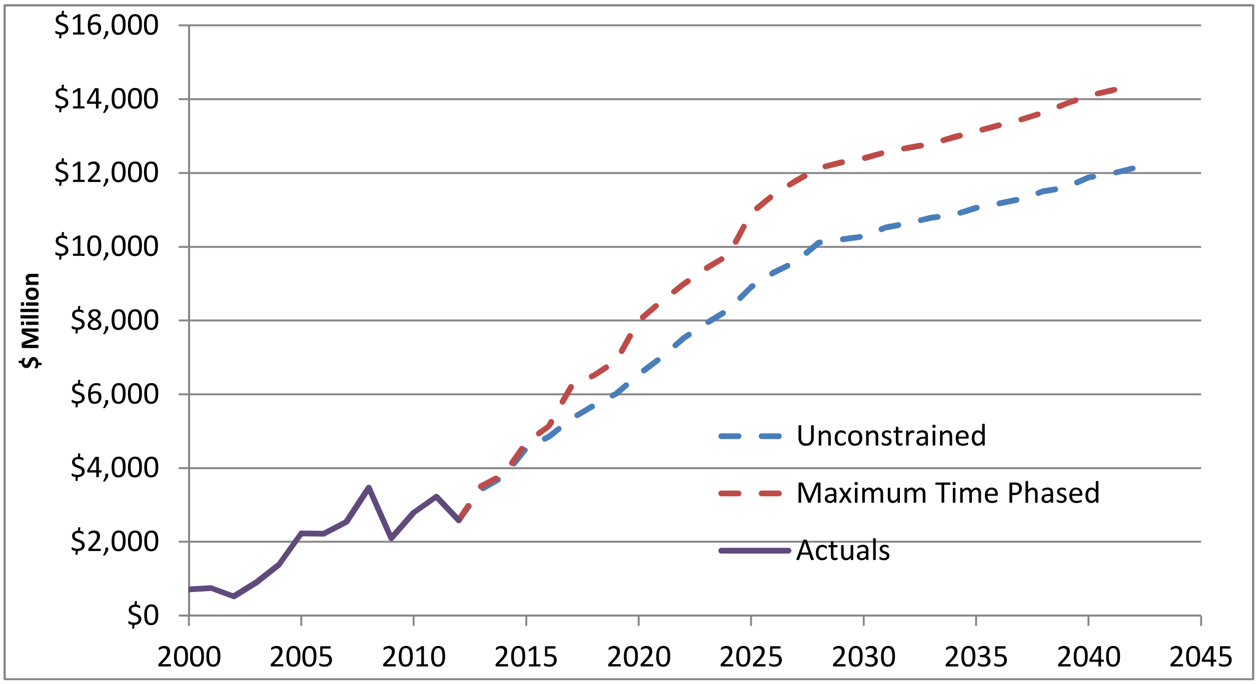
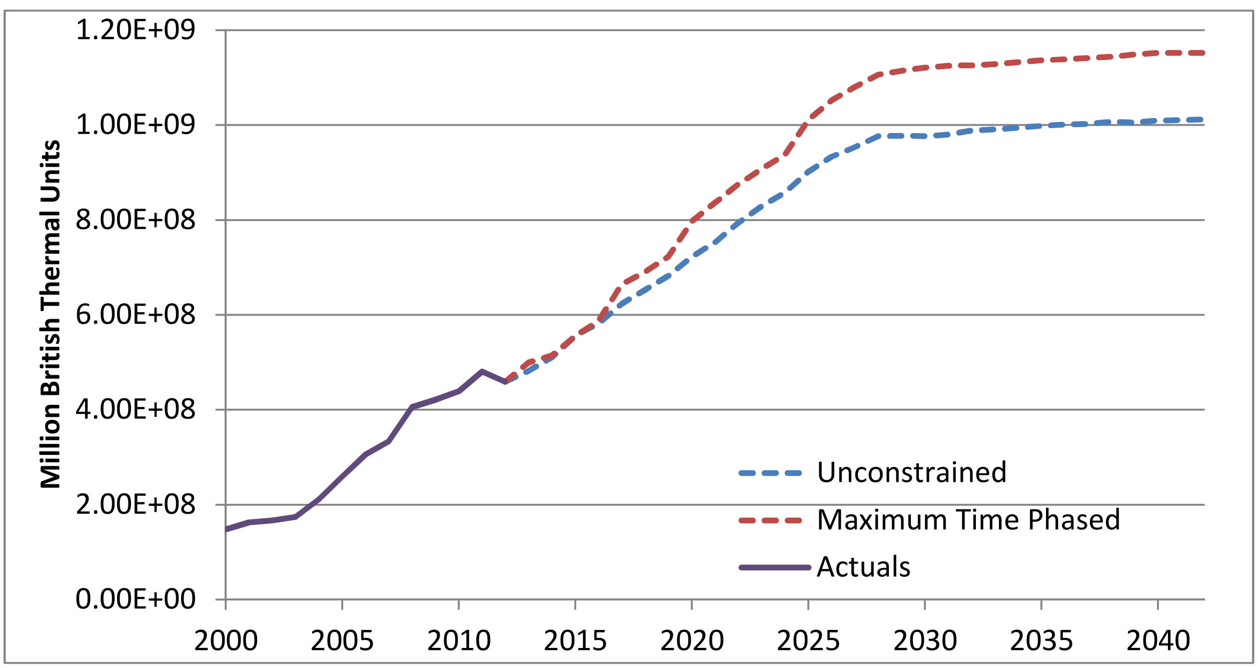


Figure 31: Comparison of Maximum and Unconstrained Forecasts (Million British Thermal Units)



7 Constrained Forecast Model

The constrained forecast model estimates the limitations to total potential energy product production resulting from inadequacies of the transportation network serving the Uinta Basin. This section reviews the modeling approach, the traffic and network capacity estimates, the estimates of transportation requirements by commodity type, and other data and assumptions applied in the analysis, and then presents an assessment of the production forecast given the identified transportation constraints.

7.1 Constrained Forecast Approach

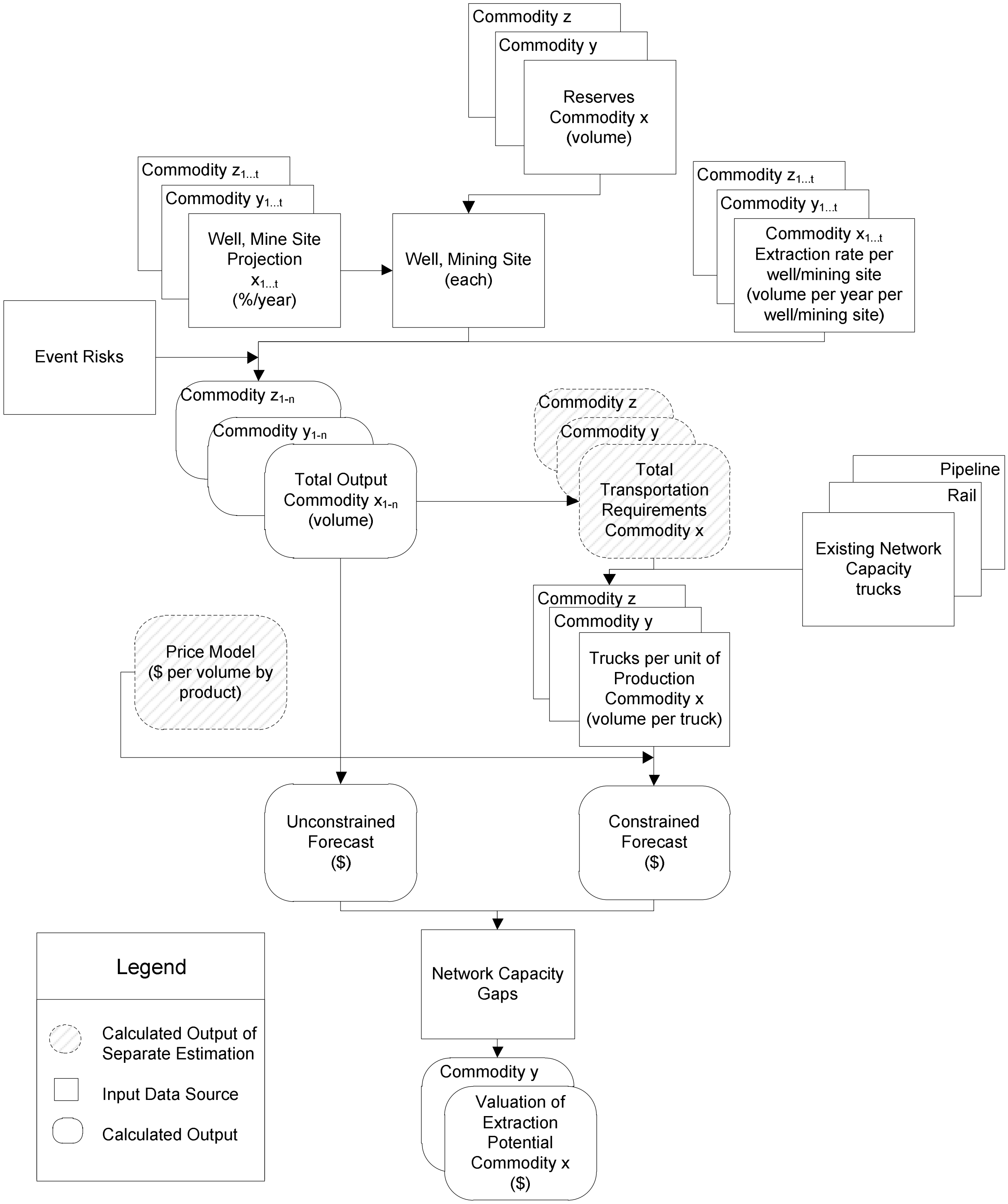
The constrained forecast starts from the transportation-unconstrained production volumes described in section 6.4. These output volumes have associated transportation requirements, both for construction and for operation of extraction facilities (wells and mining sites). These transportation requirements are estimated from a bottom-up build up of specific materials requirements and output volumes and estimates of the transportation inputs required to carry these volumes. Numbers of new wells and mines are multiplied by the number of truck load equivalents required to build these facilities, and the numbers of all operating wells and mines (new and previously built facilities) are multiplied by the number of truck load equivalents required to carry the operational inputs plus the truck loads and/or pipeline volumes forecasted to be generated at each facility. This results in a forecast of the total transportation requirements for the unconstrained output forecast.

This transportation demand estimate is added to the baseline volumes of existing roadway traffic other than oil and gas trips, as estimated from the Utah Statewide Travel Model (USTM), as well as to pipeline volume demand estimates, resulting in a total transportation demand forecast.[37] These potential trips and volumes are then assigned to specific roadway and pipeline routes based on the input and output origin and destination analysis and on the historical usage of the roadway routes in the analysis. This results in a forecast of unconstrained transportation demand by major route. These are compared to the capacity of these routes to safely carry traffic and production volumes. Where the demand exceeds capacity, the model reduces output proportionally across the commodities included in our study, to the point that there is sufficient capacity to serve the transportation demand. Likewise for commodities carried by pipeline, the estimated existing pipeline capacity is compared to unconstrained demand and reduced to the point that output does not exceed capacity. This exercise results in a forecast of output constrained by capacity, which we are calling the constrained forecast.

The gap between the unconstrained forecast and the constrained forecast is valued based on the forecast achievable prices for the lost energy production. The relationship between these calculation elements is provided again in Figure 32, for ease of reference.

[37] The pipeline demand of the unconstrained forecast would be the total pipeline demand

Figure 32: Structure and Logic of the Constrained Forecast



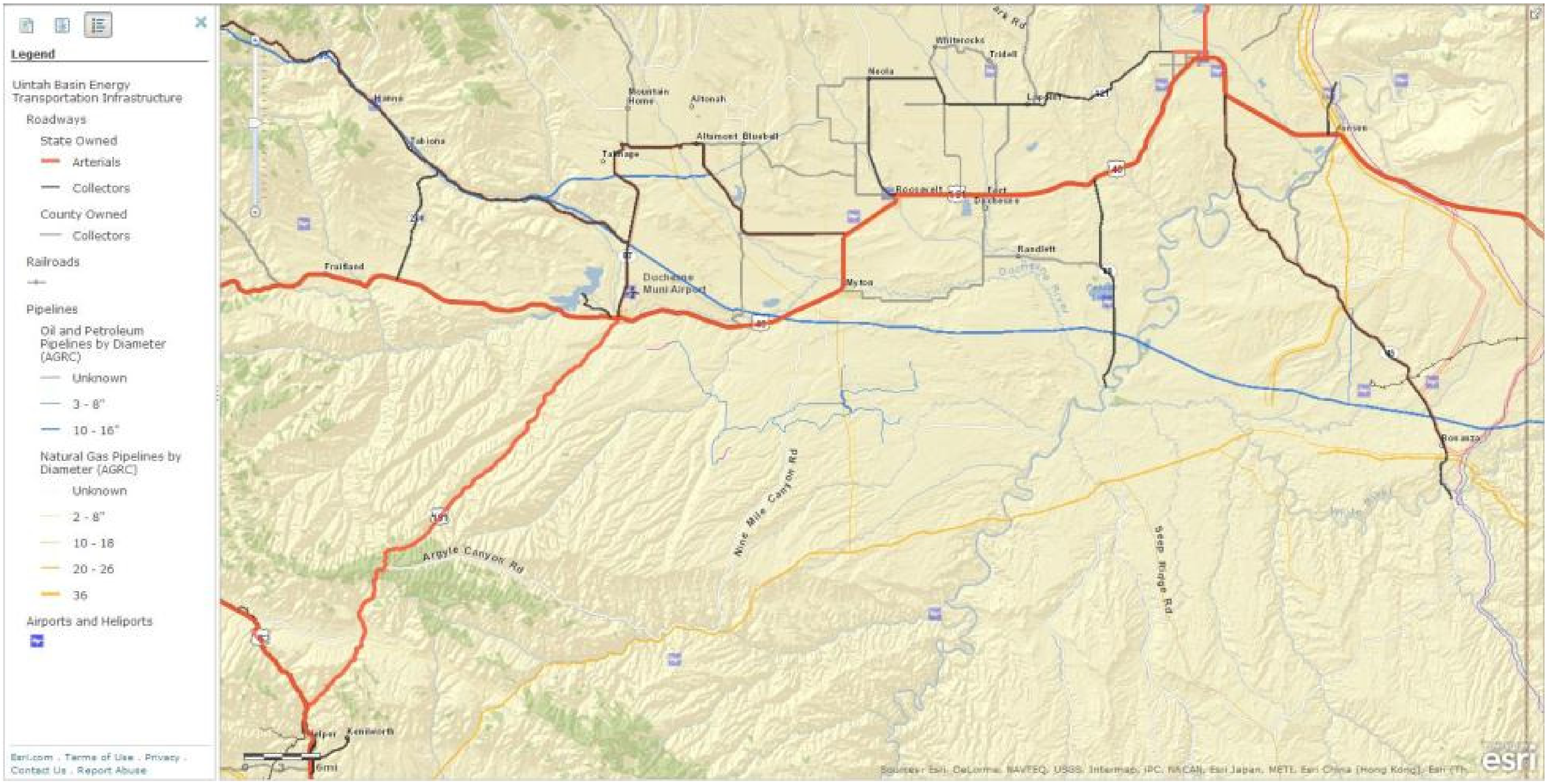
7.2 Transportation Constraints

The constrained forecast model focuses on defining the gap between the energy commodity production level that is achievable with the existing and planned transportation network and the production level that industry would be likely to generate if transportation were not a constraint. This section examines the existing transportation network and planned improvements and describes the study's approach to evaluating the network's constraints. Further technical details regarding the capacity of existing transportation corridors and modes can be found in Appendix B.

7.2.1 Existing Roadway Network

Figure 33 shows the current energy-related transportation infrastructure in the Uinta Basin, which is composed of roads, pipelines, and, to a limited extent, railways.

Figure 33: Existing Energy-Related Transportation Infrastructure in the Uinta Basin



Source: UPlan

Arterials

The transportation network in the Uinta Basin is predominantly roads and the arterials that provide connectivity to other parts of the region. U.S. highway 40 (U.S. 40) is a major east-west corridor across the heart of the Uinta Basin connecting northwestern Colorado with U.S. Interstate 80 (I-80) and points west. U.S. highway 191 (U.S .191) traverses north to south through the Uinta Basin providing connectivity to the energy activity in southwest Wyoming and to the entire southern Utah region.

U.S. 40 is classified as a principal arterial. It serves as an important facility for transporting people, goods, and services to and from the Wasatch Front and U.S. Interstate 15 (I-15). The amount of traffic on U.S. 40 just east of Strawberry Reservoir is 50% greater than the traffic at the Colorado border. U.S. 40 is typically posted 65 miles per hour (mph) outside city boundaries from I-80 to the Colorado border and is the main west-east transportation artery serving the Uinta Basin. Except for within the town limits of Roosevelt and Vernal, the capacity of U.S. 40 is adequate to handle current traffic. However, slow-moving vehicles, including many vehicles associated with energy production, continue to cause operational and safety issues within city limits. Aside from pavement and routine maintenance, improvements have focused on providing passing lanes, providing truck climbing lanes, and upgrading intersections that accommodate increasing volumes of truck turning movements and/or general traffic.

U.S. 191 is a north-south corridor that enters and exits the southwest and northeast areas of the Uinta Basin. Between the cities of Duchesne and Vernal, U.S. 191 shares designation with U.S. 40. U.S. 191 is classified as a minor arterial. The portion heading southwest from Duchesne provides the Uinta Basin with connectivity to U.S. Interstate 70 (I-70) and all of southern Utah. The portion heading north from Vernal provides connectivity to southwestern Wyoming. The northeast leg currently carries three times the traffic that the southwest leg carries, partially due to energy activity between Wyoming and the Uinta Basin. There is also a significant amount of recreational traffic north of Vernal to Flaming Gorge reservoir and dam and the roadway provides access to the eastern portion of the Uinta Mountains. While some sections of U.S. 191 are posted 65 mph, both legs traverse mountain passes with steep, winding, and, in some cases, narrow areas. There are some truck climbing lanes, but opportunities for passing slow-moving vehicles are limited. Aside from pavement and routine maintenance, improvements on U.S. 191 have focused on safety. Guardrails, signs, and two runaway-truck ramps were recently constructed north of Vernal on a steep segment containing many switchbacks. There are periods of heavy snow in the winter that frequently result in closures on portions of U.S. 191.

Collectors South of U.S. 40

There are fewer farming and ranching communities south of U.S. 40 than to the north. As a result, the majority of traffic on the collector system to the south can be assumed to be serving the energy industry.

Sand Wash Road (5580 West) heads south from U.S. 40 approximately 2 miles west of Myton. Classified as a major collector, this Duchesne County road provides access to a Newfield Exploration facility and a significant number of oil wells. It is paved for approximately 10 miles south of U.S. 40 with minimal shoulders. Where the pavement ends, the facility splits into two gravel roads which that split numerous times and provide access to wells in Duchesne and Uintah counties.

Approximately 2 miles south of the U.S. 40-Sand Wash Road intersection, Nine Mile Road heads south off Sand Wash Road. Also a Duchesne County road, Nine Mile Road is classified as a major collector and is paved about halfway to the Carbon County border. Beyond the pavement, the facility is graded gravel. Although there are a few farms near U.S. 40, the facility predominantly services oil wells and tourist traffic to the Nine Mile Canyon petroglyph and pictograph sites. The facility connects with U.S. highway 6 (U.S. 6) east of Wellington.

State Route 88 (S.R. 88) heads south from U.S. 40 between Roosevelt and Vernal. The 17-mile paved road has substandard shoulders and is classified as a major collector. There are no towns of significant size along the route, which mainly services energy traffic. In 2011, more than 70% of the traffic was single or combination trucks. The State designation ends after the bridge across the Green River where Uintah County attains ownership of Seep Ridge Road. Until recently, this was a gravel road providing access to oil wells in the area. UTSSD recently secured funding and permitting to widen and pave the road 45 miles to the Grand County border. When completed, the road will be two lanes wide with standard shoulders.

State Route 45 (S.R. 45) heads south off U.S. 40 in the town of Naples. The 40-mile paved facility has substandard shoulders and is classified as a major collector. The northern 6 miles of the road carry nearly 10 times more traffic than the southern 30 miles. S.R. 45 also provides access to the Deseret Power Station where approximately 25% of S.R. 45's traffic is generated. At its southern end, S.R. 45 carries about 10% of the traffic on the northern portion. Two graded county roads access oil wells from the southern end of S.R. 45.

Collectors North of U.S. 40

The collector system north of U.S. 40 connects the many farming and ranching communities located between the Uinta Mountain foothills and U.S. 40. Although there is some energy exploration and production, the collectors serve the energy industry and the communities equally. Unlike the collectors south of U.S. 40, the traffic is not predominantly energy-related.

State Routes 121 and 87 (S.R. 121 and S.R. 87) wind through small communities between Duchesne, Roosevelt, and Vernal. The highest volumes of traffic are within the limits of those three cities.

State Routes 35 and 208 (S.R.35 and S.R. 208) provide access to several small communities in the northwest corner of the Uinta Basin. S.R. 35 also provides recreational access to the southwestern portion of the Uinta Mountains and connects with the Park City area. The route is steep and conditions are often windy over the mountain pass which is sometimes closed to traffic in the winter. The traffic volumes of these two collectors are one-fifth of the volumes on S.R. 121 and S.R. 87.

Existing Traffic Counts

The study team collected forecasts of traffic counts from 2011 to 2040 by major routes categorized by three different vehicle types—passenger car, single truck, and combination trucks—and by major highway segments (see Appendix A for a full discussion). Table 28 and Table 29 show forecasts of passenger car annual average daily traffic (AADT) and non-energy truck AADT. Up to 10% of the total AADT is trucks on non-energy-related trips.[38] The remaining 90% of the total AADT are assumed to be oil and gas related trips.

[38] 10% assumption based on subject-matter expert input.

Table 28: Forecast of Passenger Car AADT by Highway Segment – One Way

Highway Segment	Direction	2011	2020	2030	2040
U.S. 40 west (Wasatch County to S.R. 208)	West	1,445	1,500	1,430	1,555
U.S. 40 central (S.R. 208 to Naples)	Local	2,610	2,905	3,010	3,310
U.S. 40 east (Naples to Colorado)	East	1,045	1,425	1,915	2,605
U.S. 191 south (Carbon County to U.S. 40)	South	170	775	665	1,155
U.S. 191 north (U.S. 40 to Daggett County)	North	695	865	1,085	1,405
S.R. 35 (S.R. 208 to S.R. 87)	Local	65	315	275	490
S.R. 45	Local	960	985	995	1,015
S.R. 87	Local	440	560	555	660
S.R. 88	Local	325	330	335	345
S.R. 121	Local	730	925	1,090	1,230
S.R. 208	Local	90	85	85	90
Nine Mile Road/5800 West	Local	45	45	45	50
All other local traffic	Local	120	165	163	208
Total passenger car trips in the region		**8,741**	**10,881**	**11,648**	**14,118**

Source: Study team computation, based on UDOT USTM.

Table 29: Forecast of Non-Energy Trucks AADT by Highway Segment – One Way

Highway Segment	Direction	2011	2020	2030	2040
U.S. 40 west (Wasatch County to S.R. 208)	West	225	238	252	295
U.S. 40 central (S.R. 208 to Naples)	Local	405	446	485	547
U.S. 40 east (Naples to Colorado)	East	181	224.5	282.5	362
U.S. 191 south (Carbon County to U.S. 40)	South	27	93	90	147
U.S. 191 north (U.S. 40 to Daggett County)	North	93	118	154	203
S.R. 35 (S.R. 208 to S.R. 87)	Local	8.5	38	36	62
S.R. 45	Local	200	202	204	206
S.R. 87	Local	69	83	84	96
S.R. 88	Local	117	117	118	119
S.R. 121	Local	111	131	149	163
S.R. 208	Local	17	17	18	18
Nine Mile Road/5800 West	Local	5	5	5	5
All other local traffic	Local	14	19	19	24
Total passenger car trips in the region		**1,473**	**1,732**	**1,894**	**2,244**

Source: Study Team computation, based on UDOT USTM
Note: Both single and combination trucks included in this table.

7.2.2 Existing Railway Network

The Uintah Railway was founded in 1902 to transport gilsonite[39] from the Uinta Basin to Mack, Colorado, which is near Grand Junction. It was disbanded in 1939 after gilsonite prices experienced a drastic decline. The only railroad currently operating in the Uinta Basin is the Deseret Power Railroad. The 35-mile-long railway transports coal from the Deserado mine in northwestern Colorado to the Bonanza power plant near Vernal, Utah. Currently, the Deseret Power Railroad runs a two-unit, 35-car train twice daily.

7.2.3 Existing Pipeline Network

There is a fairly extensive network of private pipelines that carry natural gas and petroleum products throughout the Uinta Basin. Below is a summary of the existing pipelines within the Uinta Basin.

Table 30: Existing Basin Pipeline Facilities by Commodity Type

Summary of Existing Length of Pipeline Miles	
Commodity	**Total Miles**
CO_2 and gas gathering	103.5
Natural gas	1,117.4
Petroleum liquids (crude, NGL, petroleum, etc.)	498.4

Source: Utah Geological Survey, Oil and Gas Fields Map of Utah, Map 203 DM
Note: Natural gas liquid (NGL).

[39] A trademarked, naturally-occurring asphalt found only in the Uinta Basin, also known as uintaite.

7.2.4 Planned Roadway Capacity Improvements

The USTM that was used to generate baseline travel demand estimates provides year 2020, 2030, and 2040, forecasts for a build scenario, which assumes that all projects in UDOT's 2011–2040 Long-Range Transportation Plan are completed as planned. Table 31 lists the improvements in the UDOT 2011–2040 Long-Range Transportation Plan for Duchesne and Uintah counties. These improvements are contained in the USTM and are separated by phase. Our roadway capacity estimates therefore assume a certain level of ongoing investment in the Uinta Basin, and any capacity shortfalls discussed in our forecasts are above and beyond these planned investments.

Table 31: Planned Capacity Projects

County	Project Name and Location	Length	Improvement Type	Estimated Cost
Phase One 2011-2020				
Duchesne	U.S. 40 mile post (MP) 70.1 to MP 100.0 Duchesne Urban Area STIP CD	29.9	Passing lanes	$18,000,000
Uintah	S.R. 121 MP 37.3 to MP 40.3 (existing 3-lane)	3.0	Widening	$5,000,000
Uintah	U.S. 40 widen eastbound and westbound from 1 lane to 2 lanes from MP 130.3 to MP 133.4	3.1	Passing lanes	$5,000,000
Uintah	U.S. 40 MP 152.0 to 153.0 eastern limit of Naples	1.0	Passing lanes	$4,000,000
Uintah	U.S. 40 widen eastbound and westbound from MP 117.8 to MP 119.4 Roosevelt and Ballard Urban Area	1.6	Passing lanes	$10,000,000
Phase One Total				**$42,000,000**
Phase Two 2021-2030				
Duchesne	U.S. 40 MP 107.6 eastern limit of Duchesne to western limit of Roosevelt	1.2	Passing lanes	$2,000,000
Duchesne	U.S. 191 widen northbound and southbound from 1 lane to 2 lanes from MP 262.2 to MP 271.8	9.6	Passing lanes	$14,000,000
Wasatch/Duchesne	U.S. 40 widen eastbound and westbound from MP 37.5 to MP 69.2 Daniels Summit to western limit of Duchesne	31.7	Passing lanes	$22,000,000
Phase Two Total				**$38,000,000**
Phase Three 2031-2040				
Uintah/Daggett	U.S. 191 widen northbound and southbound from 1 lane to 2 lanes from MP 363.6 to MP 392.6	29.0	Passing lanes	$44,000,000
Phase Three Total				**$44,000,000**

Source: UDOT USTM

7.2.5 Estimated Roadway Capacity Limits

For the purpose of analyzing trip demand, the roadway routes are aggregated into five categories: (1) trips to and from west of the Uinta Basin, (2) trips to and from east of the Uinta Basin, (3) trips to and from south of the Uinta Basin, (4) trips to and from north of the Uinta Basin, and (5) trips within the Uinta

Basin, also called local trips. The assignment of routes to these categories is described in Table 32 and Table 33, and a map is provided in Figure 34.

Table 32: Forecast of Minimum Traffic Capacity by Highway Segment – One-Way in Passenger Car Equivalent (PCE)

Highway Segment	Direction	2011	2020	2030	2040
U.S. 40 west (Wasatch County to S.R. 208)	West	4,650	4,650	5,650	5,650
U.S. 40 central (S.R. 208 to Naples)	Local	2,850	3,250	3,250	3,250
U.S. 40 east (Naples to Colorado)	East	3,250	3,350	3,350	3,350
U.S. 191 south (Carbon County to U.S. 40)	South	3,300	3,300	3,450	3,450
U.S. 191 north (U.S. 40 to Daggett County)	North	2,550	2,550	2,550	2,550
S.R. 35 (S.R. 208 to S.R. 87)	Local	3,200	3,200	3,200	3,200
S.R. 45	Local	3,400	3,400	3,400	3,400
S.R. 87	Local	3,300	3,300	3,300	3,300
S.R. 88	Local	3,450	3,450	3,450	3,450
S.R. 121	Local	3,200	3,350	3,350	3,350
S.R. 208	Local	3,300	3,300	3,300	3,300
Nine Mile Road/5800 West	Local	1,700	1,700	1,700	1,700
All other local traffic	Local	100	100	100	100

Source: UDOT USTM

Note: Capacity numbers are passenger car equivalent (PCE). One unit of passenger car is 1 PCE, while one unit of truck could range from 2 to 4.5 PCE.

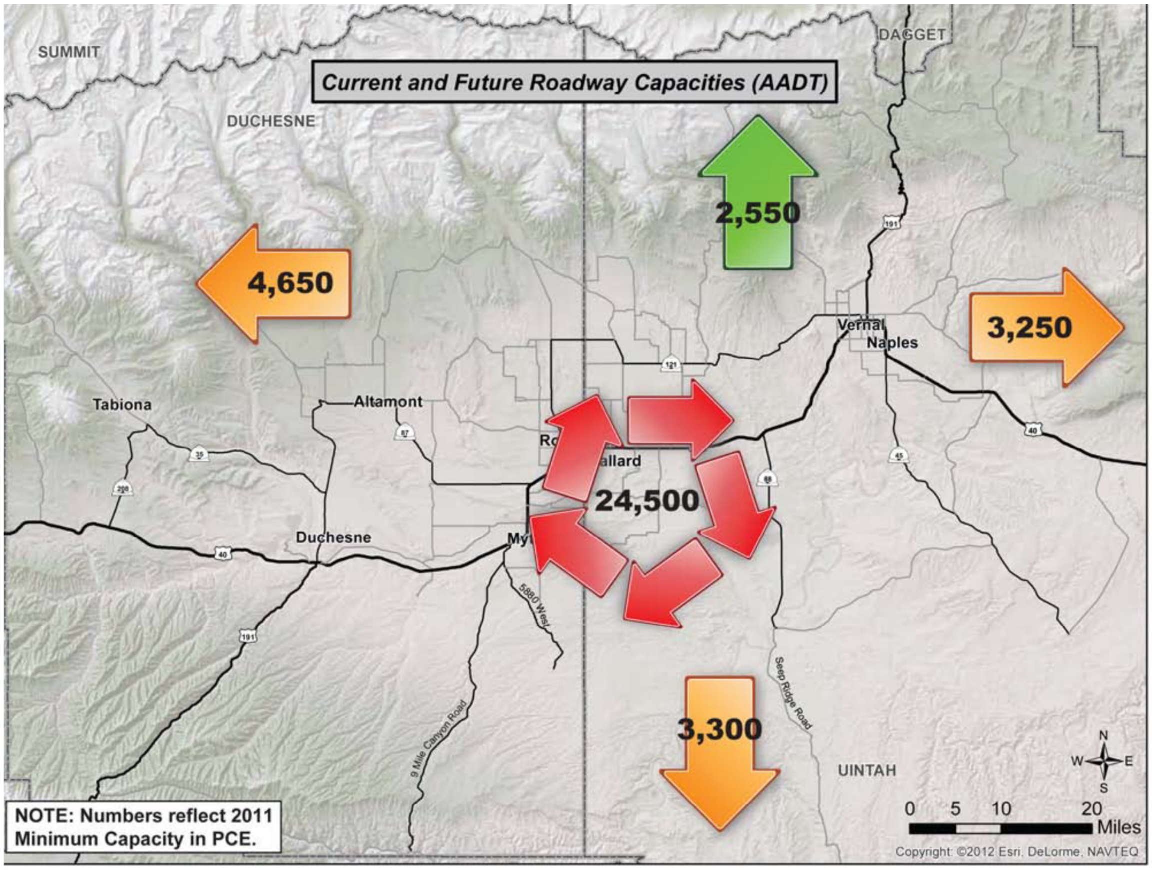
Table 33: Forecast of Minimum Traffic Capacity by Major Direction – One Way

Highway Segment	2011	2020	2030	2040
East	3,250	3,350	3,350	3,350
West	4,650	4,650	5,650	5,650
North	2,550	2,550	2,550	2,550
South	3,300	3,300	3,450	3,450
Local	24,500	25,050	25,050	25,050

Note: Minimum traffic capacities are compiled from Table 32. Directions east, west, north, and south were averaged. Local traffic minimum capacity was computed by summing corresponding highway segments.

Figure 34 shows the roads analyzed in this study. It also shows the current minimum and average capacity of the facilities along with the capacities that will be achieved from completion of all three phases of UDOT's long-range transportation plan.

Figure 34: Roads and Directional Capacity Limits Included in the Constrained Forecast



Each of the assessed routes has specified capacities in terms of passenger car equivalents (PCEs) per day. The capacities represent the average daily vehicle capacity across the length of the route and the minimum capacity along any point in the route.

7.2.6 Estimated Pipeline Capacities

Unlike roadways, the existing road network, the existing pipeline network has a diversity of ownership, making capacity estimation more problematic. Further, pipeline throughput is a function of more than just size—pressure, viscosity of product, and other factors determine ultimate capacities. Table 34 lists high-level estimates of pipeline capacity by facility and the assumed capacity growth rate applied in this analysis.

Table 34: Pipeline Capacity by Facility Type, Forecast Capacity Growth

Summary of Existing Pipeline Capacity		
Commodity	**2012 Daily Capacity**	**Average Annual Capacity Growth Rate, Assumed**
Natural gas	1,260 million cubit feet equivalent	3%
Petroleum liquids (crude, NGL, petroleum, etc.)	19,400 Barrel	3%

Note: Natural gas liquid (NGL); millions of cubic feet equivalent (MMCFE); Barrel (BBL). Daily capacities calculated from pipeline length and diameter information in UPlan.

7.3 Transportation Requirements by Commodity

The previous section discusses existing traffic conditions and transportation and pipeline capacities in the study area. In order to fully assess the extent to which the network capacities limit energy production, an evaluation of the transportation demand imposed by new output is required. Detailed traffic requirements and assumptions are described in the following five subsections:

1. Transportation Requirements for Conventional Vertical Oil and Gas Well Construction and Operation
2. Transportation Requirements for Horizontal Hydraulically Fractured Wells
3. Transportation Requirements for Oil Shale Mining Operations
4. Transportation Requirements for Oil Sands Mining Operations
5. New Energy Trips Distribution by Direction

Oil and gas transportation requirements were added to the existing non-energy traffic in Table 34 and compared to the capacity of the major routes. The part of overall demand that exceeds capacity is considered lost output in the transportation-constrained forecast.

7.3.1 Transportation Requirements for Conventional Vertical Oil and Gas Well Construction and Operation

Many of the transportation requirements for building and operation of conventional vertical wells were derived from a UDOT freight planning study conducted in 2006. In this section, transportation requirements are divided into three parts: one-time capital investment, general maintenance and operational inputs, and operational outputs.

The first element is the one-time need for site construction. Table 35 provides truckload requirements for one-time conventional oil or gas well drilling and completion. The wide variation in total, on-time truckloads needed for initial well set-up, ranging from 416 to 1,404, is primarily driven by varying freshwater requirements across geological types and well depths.

The second and third elements are on-going operational inputs and outputs are summarized in Table 36. A major input commodity, water, is mentioned in the report, but the specific amounts required were not specified. Produced waste removal requirements range from one truck per week to three to five trucks per day per well. While estimated truck requirements for well construction, maintenance, and water removal are the same for both gas and oil wells, they are different for operational output related to energy transportation. Conventional natural gas is assumed to be transported by pipeline, consistent with industry input collected through interviews. In contrast, crude oil is assumed to be carried out by trucks with an average capacity of 200 barrels or, to a limited extent, by pipeline[40].

A second estimate of operational transport requirements came from analyzing current and forecasted transportation data provided by DOGM. It is estimated that about 300 to 400 truck loads per year are required to operate a single well, which is in line with UDOT estimates from 2006.

In summary, according to UDOT[41], there is a one-time need of 416 to 1,404 one-way truck trips to construct, drill, and complete a single vertical conventional well. Operational input requirements are unspecified. Water removal during operations requires 52 to 1,500 truckloads per well per year. A second estimate suggests 300 to 400 truckloads per well per year for a combined operational inputs and outputs.

Table 35: One-Time Truckload Requirements for Drilling and Completing a Single Conventional Gas or Oil Well - One-Time Truck Trips

Purpose	Low	High	Source	Notes
Well drilling, truckloads	212	1185	Highway Freight Traffic Associated with the Development of Oil and Gas Wells, UDOT, 2006	Includes the following activities: Ground surveys; trucking in construction equipment; transport drill rig to site; transport water for drilling rig, bring in fresh water, and completions; dispose of flowback and produced water; transport in and remove drilling mud, cast well, and cement powder. Bringing in fresh water requires the most truckloads (100 to 1,000).
Completion of rig, truckloads	171	177	Highway Freight Traffic Associated with the Development of Oil and Gas wells, UDOT, 2006	Requires the following activities: perform general rig maintenance (one-time maintenance), remove drilling rig, complete rig preparation, set up rig, well tubing, perforate casing and cement outer lining, and frac sand.
Well finalization, truckloads	30	42	Highway Freight Traffic Associated with the Development of Oil and Gas Wells, UDOT, 2006	Includes the following activities before the well can produce oil or gas: remove completion rig, close reserve pits, and build facility.
Total	**416**	**1,404**	**Total number of one-way trips required to have wells ready for production of oil or gas**	

40 The largest Uinta Basin area waxy crude producer indicated in interviews that they never transport by pipeline. However, certain other producers indicated that waxy crude is occasionally transported via one of the Chevron pipelines, i.e. during summer months when temps are high enough to keep the crude from setting up.

41 Highway Freight Traffic Associated with the Development of Oil and Gas Wells, UDOT, 2006

Table 36: Average Annual Truckload Requirements for Operating a Single Conventional Well - Annual Truck Trips

Purpose	Low	High	Source	Notes
General maintenance, truckloads	0.3	12	Highway Freight Traffic Associated with the Development of Oil And gas Wells, UDOT, 2006	Maintenance includes acid treatment to prevent corrosion. Up to 25 to 40 truckloads of equipment are required.
Wastewater Removal	50	1,500	Highway Freight Traffic Associated with the Development of Oil And gas Wells, UDOT, 2006	Oil and gas wells bring water to the surface. This water is stored in onsite tanks and must be trucked to the disposal site.
Total	**50**	**1,512**	**Total number of one-way trips (excluding crude oil transportation) required for well operation**	

7.3.2 Transportation Requirements for Horizontal Hydraulically Fractured Wells

This section provides estimates of transportation requirements for hydraulically fractured wells. In comparison with vertical conventional wells, horizontal wells are known to have higher material, and therefore truck trip, requirements to build wells. Similar to other well or mining site developments, transportation requirements can be divided into three stages: one-time capital investment, general maintenance and operational inputs, and operational outputs.

The first stage is a one-time need of the site construction. Table 37 provides estimates from a 2012 Deloitte study and from an HDR study from 2011. Combined estimates from Deloitte and HDR provide that it takes about 653 to 1,193 truck loads to drill and complete a single horizontal well.

The second and third stages are operational inputs and outputs, which are summarized in Table 38. We estimate that approximately four to seven truckloads for chemical and fuel transportation are needed and that 200 to 1,500 truckloads are required to remove wastewater from the average horizontal well. For energy commodity transportation, all natural gas is assumed to move by pipeline, while crude oil is assumed to continue to be transported by trucks or, in limited volumes, by pipeline.

In summary, we estimate about 650 to 1,200 one-way truck trips to construct, drill, and complete a single horizontal well. Additionally, operations require about 200 to 1,500 truck trips per year to move energy product out of the Uinta Basin.

Table 37: One-Time Truckload Requirements for Constructing, Drilling, and Completing a Single Horizontal Hydraulically Fractured Well - One-Time Truck Trips

Purpose	Low	High	Source	Notes
Well drilling, truckloads	200	400	On the Road Again: Managing Transportation Logistics for Unconventional Drilling (Deloitte), 2012/Infrastructure Challenges – Effects of an Oil Boom (HDR), 2011	Construction of horizontal hydraulically fractured wells includes the following components: temporary water pipes, line pipe, gravel, and facility and construction supply. Water and gravel comprise most of the truckloads in this stage are for hauling gravel.
Completion of rig, truckloads	253	280	Deloitte, 2012/HDR, 2011	Drilling stage consists of the following components: vacuum trucks for drilling, move of rig, fresh water, drilling equipment and material, and absorbent disposal/sawdust.
Well finalization, truckloads	200	513	Deloitte, 2012/HDR, 2011	Includes the following activities before the well can produce oil or gas: remove completion rig, close reserve pits, and build facility.
Total	**653**	**1,193**	**Total number of one-way truckload trips required to have wells ready for production of oil or gas**	

Table 38: Average Annual Truckload Requirements for Operating a Single Horizontal Hydraulically Fractured Well - Annual Truck Trips

Purpose	Low	High	Source	Notes
Operational inputs, truckloads	4	7	Infrastructure Challenges – Effects of an Oil Boom (HDR)	For import of chemicals and fuel.
Wastewater removal, truckloads	200	1,500	Infrastructure Challenges – Effects of an Oil Boom (HDR)/Highway Freight Traffic Associated with the Development of Oil and Gas Wells, UDOT, 2006	Oil and gas wells bring water to the surface. This water is stored in onsite tanks and must be trucked to the disposal site. Upper estimate based on UDOT estimates for all wells, inclusive of directionally drilled wells.
Total	**204**	**1,507**	**Total number of one-way truckload trips (excluding crude oil transportation) required for well operation**	

In addition to the operational trips described in Table 38 above, we assume that conventional oil is carried at the forecasted volume of output on a basis of 200 barrels of oil per truck and that all natural gas outputs are carried by pipeline.

7.3.3 Transportation Requirements for Oil Shale Mining Operations

This section provides estimates of transportation requirements for oil shale mining construction and operations. Similar to other well and mining development, transportation requirements can be divided into three stages: one-time capital investment, general maintenance and operational inputs, and operational outputs.

As described in Table 39, 1,100 to 1,300 trips are needed to accommodate all construction activity for the initial construction of a single oil shale mining site.

Requirements for operation of the site, which are summarized in Table 40, are based on estimates by the Institute for Clean and Secure Energy (ICSE) of commodities required per barrel of crude oil equivalent produced. Production from oil shale requires constant inputs of water, labor, electricity, natural gas, and steam. For example, an average of 5.6 barrels of water is needed to produce one barrel of crude oil. These have been converted to truckloads based on standard measures of the capacity per truckload.

In summary, there is a one-time need of one-way 1,100 to 1,300 one-way truck trips to accommodate construction. For an oil shale site with 50,000 barrels per day production, operational inputs require an average of 750,000 one-way truck trips per year, and operational outputs require an average of 160,000 one-way truck trips per year.

Table 39: One-Time Truckload Requirements for Setting up a Shale Oil Site - One-Time Truck Trips

Purpose	Low	High	Source	Notes
Initial construction, truckloads	1,100	1,300	2012 Oil Shale and Tar Sands Final Programmatic Environmental Impact Statement (EIS), Volume 2	Based on one-way truck trips estimated for the programmatic EIS.

Table 40: Average Annual Truckload Requirements for Operating a Shale Oil Site with 50,000 BPD Oil Production - Annual Truck Trips

Purpose	Low	High	Notes
Operational inputs, truckloads	700,000	800,000	Based on : Institute for Clean and Secure Energy (ISCE)estimates of volumes of water fuel and labor required.
Operational outputs other than energy commodity removal, truckloads	140,000	200,000	Based on ICSE estimates of volumes of sulfur, and ammonium sulfate.
Total	**840,000**	**900,000**	**Total number of one-way truckload trips (excluding crude oil transportation) required for mine operation**

In addition to the operational trips described in Table 40 above, we assume that the synthetic crude oil that is produced is carried at the forecasted volume of output on a basis of 200 barrels of oil per truck.

7.3.4 Transportation Requirements for Oil Sands Mining Operations

This section provides estimates of transportation requirements for oil sands mining construction and operations. Similar to other well and mining development, transportation requirements can be divided into three stages: one-time capital investment, general maintenance and operational inputs, and operational outputs.

Table 41 describes the one-time site construction needs; 1,200 to 1,800 trips are needed to accommodate all construction activity for the initial development of a single 10,000-BPD oil sands mining facility site.

Requirements for operation of the site, which are summarized in Table 42, are based on estimates by ICSE of commodities required or produced per barrel of synthetic crude oil[42] produced. Crude oil production from oil sands requires constant inputs of water, labor, electricity, natural gas, steam, and solvents. For example, an average of 2.7 barrels of water is needed to produce one barrel of synthetic crude oil from oil sands. These have been converted to truck loads based on standard measures of truck carrying capacity per truckload.

[42] Based on an estimate of upgraded bitumen extracted.

In summary, there is a one-time need of 1,200 to 1,800 truck trips to accommodate construction. For an oil sands site with 10,000 BPD production, operational inputs require an average of 160,000 one-way truck trips per year, and operational outputs require an average 50,000 one-way truck trips per year, not including export of the produced synthetic oil other than energy commodity removal.

Table 41: One-Time Truckload Requirements for Setting up an Oil Sands Site - One-Time Truck Trips

Purpose	Low	High	Source	Notes
Initial construction, truckloads	1,200	1,800	2012 Oil Shale and Tar Sands Final Programmatic Environmental Impact Statement (EIS), Volume 2	Based on one-way truck trips estimated for the programmatic EIS.

Table 42: Average Annual Truckload Requirements for Operating an Oil Sands Mining Site with 10,000 BPD Oil Production - Annual Truck Trips

Purpose	Low	High	Notes
Operational inputs, truckloads	120,000	200,000	Based on ICSE estimates of volumes of water fuel and labor required.
Operational outputs other than energy commodity removal, truckloads	40,000	60,000	Based on ICSE estimates of volumes of sulfur, ammonium sulfate, and pet coke.
Total	**160,000**	**260,000**	**Total number of one-way truckload trips (excluding synthetic crude oil transportation) required for well operation**

Source: Institute for Clean and Secure Energy (ISCE).

In addition to the operational trips described in Table 42 above, we assume that conventional oil is carried at the forecasted volume of output on a basis of 200 barrels of oil equivalent per truck.

7.3.5 New Energy Trips Distribution by Direction

In order to distribute new energy trips by direction, the existing oil and gas trip directional distributions were analyzed.

Existing energy- related truck trips are calculated by subtracting 10% of AADT from the total truck units, which are based on data extracted from UPlan (see Appendix A). Existing energy- related truck trips by highway segment were compiled by five major directions. Table 43 shows the results.

Table 43: Distribution of New Oil and Gas Trips

Direction	Existing Oil and Gas Trips as a Percentage of Total Oil and Gas Trips
West	15.0%
East	12.0%
North	5.0%
South	2.1%
Local (9 segments combined)	66.0%

Source: Calculated from UPlan.

The table indicates that 15% of the total energy trucks are currently using roads west of the Uinta Basin and 12% are using roads east of the Uinta Basin. The largest portion, of 66%, comes from the network of local roads within the Uinta Basin.

We assume that newly generated oil and gas truck traffic from both conventional and unconventional resources will follow the same pattern as that for existing production. These newly generated oil and gas trips are added to existing traffic by direction, and total traffic volumes are analyzed against the projected capacities.

7.4 Other Modeling Assumptions

As stated in Section 7.1, the production volumes estimated for the transportation-unconstrained forecast is the starting point of the constrained forecast. The forecasted unconstrained output volumes are converted to transportation requirements. Newly generated oil and gas truck trips are distributed to the existing and planned network as described in Table 43 above, and the results are compared to network capacities (see Table 33 above). Where demand exceeds capacity, the model reduces output proportionally across the commodities to the point at which the traffic equals the capacity. Similarly for commodities carried by pipeline, if the demand exceeds the pipeline capacity, commodities transported by pipeline are reduced proportionally. The production gap is defined as the difference in total energy commodities output or values between the unconstrained and constrained approaches.

This section provides other modeling assumptions, beyond the transportation requirements by commodity type described under Section 0. Table 44 provides passenger car equivalent (PCE) values used for energy-transporting trucks. The Highway Capacity Manual (2000) provides a guide for applying appropriate PCE values for trucks, depending on the terrain type. Based on this, we apply the recommended valuation for rolling terrain: 2.0 PCE for a single truck and 2.5 PCE for a combination truck.

Table 44: Passenger Car Equivalents (PCE) for Energy-Transporting Trucks

PCE Values in Use	Notes
2.0 for single truck; 2.5 for combination truck	Highway Capacity Manual (2000) indicates that a PCE value for trucks can range between 1.5 and 4.5, depending on the type of terrain. The recommended values are 1.5 for level terrain, 2.5 for rolling terrain, and 4.5 for mountainous terrain.

Source: Highway Capacity Manual, 2000

Other modeling assumptions are summarized as follows (Table 45). First, the forecast assumes that newly generated energy trips affect constraints only during the normal operating hours (8 a.m. to 8 p.m.). We assume that 60% to 80% of the total traffic runs during normal operating hours. For the excess traffic, about 25% is diverted to non-normal operating hours. As a result, only 75% of the excess traffic is estimated as reducing output potential in the constrained forecast. Instead of assuming a full 2 trips per energy truck, 1.8 trips are assumed. This means that 10% of trucks are assumed to carry full loads in both directions. The final assumption is that about 75% of LNG production is transported by pipeline.

Table 45: Other Modeling Assumptions

Variables:	Low	Mid	High
Traffic portion in peak hours: The model assumed that 60% to 80% of the total traffic in the Uinta Basin runs during normal operating hours (8 a.m. to 8 p.m.).	60%	70%	80%
Excessive truck diversion rate: The model assumes that 25% of the excess trucks are diverted to off hours (non-normal operating hours).	20%	25%	30%
Portion of NGL transported by pipeline: The model assumes that 75% of the NGL is transported by pipeline. The rest is transported by truck as oil is.	70%	75%	80%
Number of trips per energy truck: The model assumes an average of 1.8 trips per truckload. Interview respondents and stakeholders in the Uinta Basin indicate that in most cases supply trucks carry equipment or materials in and make the return trip empty. For our transportation demand analysis we assume a certain portion of trucks will carry one load into the Uinta Basin and another load out of the Uinta Basin, but in the majority of cases, trucks will be empty in one direction.	1.7	1.8	1.9
General traffic constraints: The model assumes that newly generated energy trips affect constraints only during normal operating hours (8 a.m. to 8 p.m.).	N/A	N/A	N/A

7.5 Risk Analysis – Framework

As with the transportation-unconstrained forecast, a Monte Carlo simulation was conducted to produce the unconstrained forecast. Each variable and forecasting coefficient was varied simultaneously according to its associated probability distribution. The forecast model is designed such that event risks occur in a certain percentage of iterations, based on their defined probability of occurrence. Event risks are independent of each other and overlap or separation of occurrence between risks across iterations is a randomized product of the Monte Carlo simulation. Final probability distributions represent a combination of expected outcomes and their likelihood. For this step, the forecast model was iterated 10,000 times.[43]

7.6 Findings

This section summarizes the results of the constrained forecast. First, transportation simulation results are presented. Then, results that summarize the output gap between unconstrained and constrained models are provided.

7.6.1 Transportation Simulation Results

The following five figures present median value forecasts of traffic condition for five major directions: east, west, north, south, and local. These are based on newly generated energy trips as well as existing and forecasted non-energy trips extracted from the USTM (see Appendix A).

Figure 35 provides projections of traffic conditions at the median value (50th percentile) for major routes that are east of the Uinta Basin. As presented, traffic is expected to exceed capacity by 2013 and continue to grow rapidly to approximately 10,000 AADT by 2042, about three times the minimum capacity of 3,250 AADT. Under current constraints, a significant portion of conventional and unconventional energy

[43] See Figure 20 for a diagrammatic illustration of the simulation process.

traffic that would otherwise be generated by producers cannot be carried, resulting in a shortfall of production.

Figure 35: Transportation Projection by Energy and Non-energy Trips – One-Way Trips from and to the East

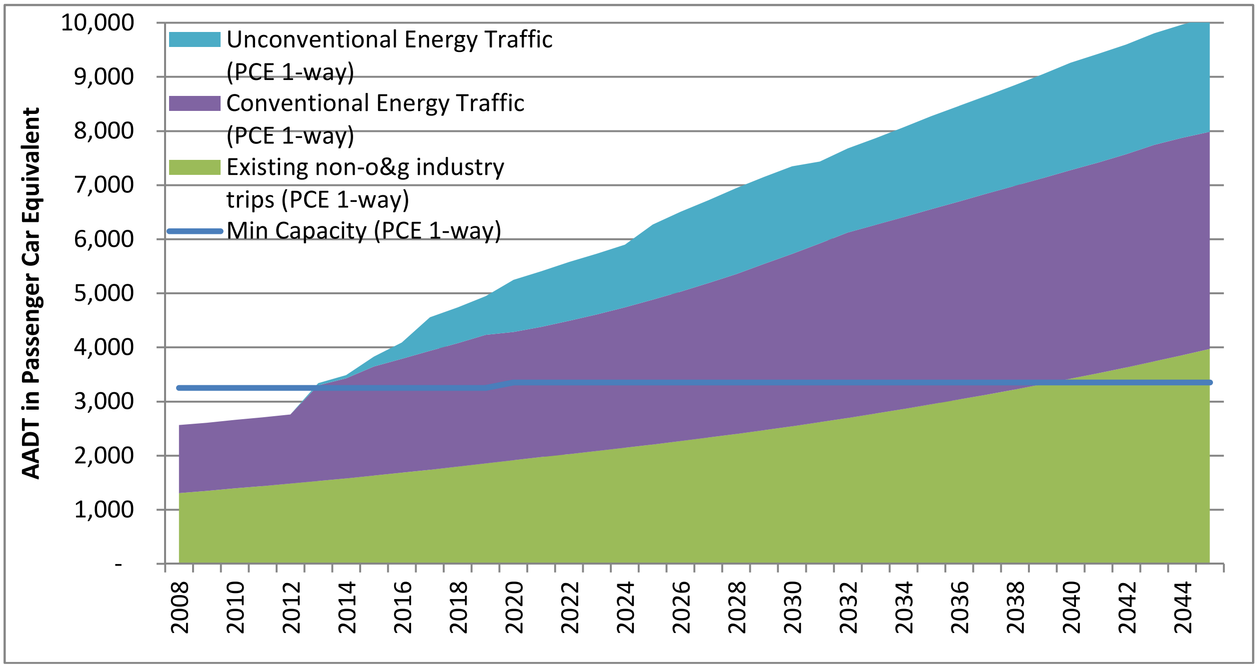
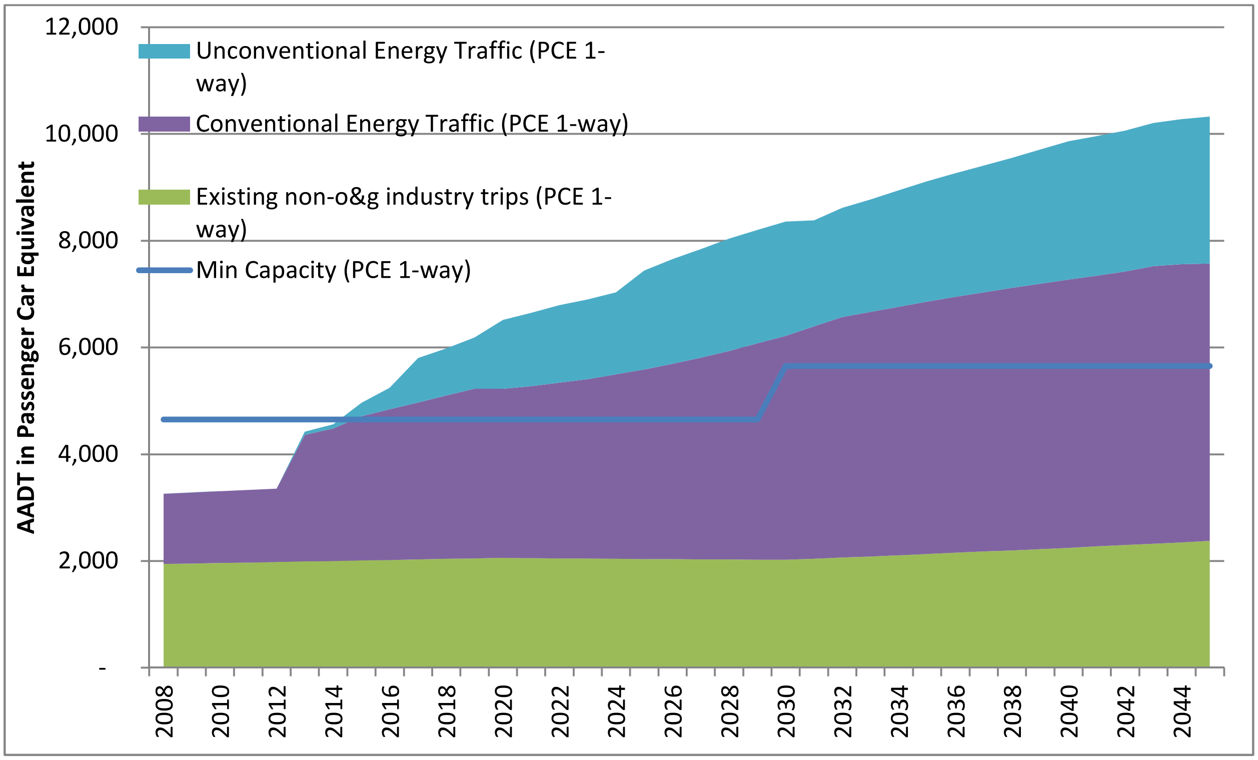


Figure 36 provides projections of traffic conditions at the median value (50^{th} percentile) for major routes that are west of the Uinta Basin. As presented, traffic is expected to achieve the capacity by 2014 and to reach more than 10,000 AADT within the study horizon. The patterns and magnitude of the traffic growth are similar to those of the easterly routes.

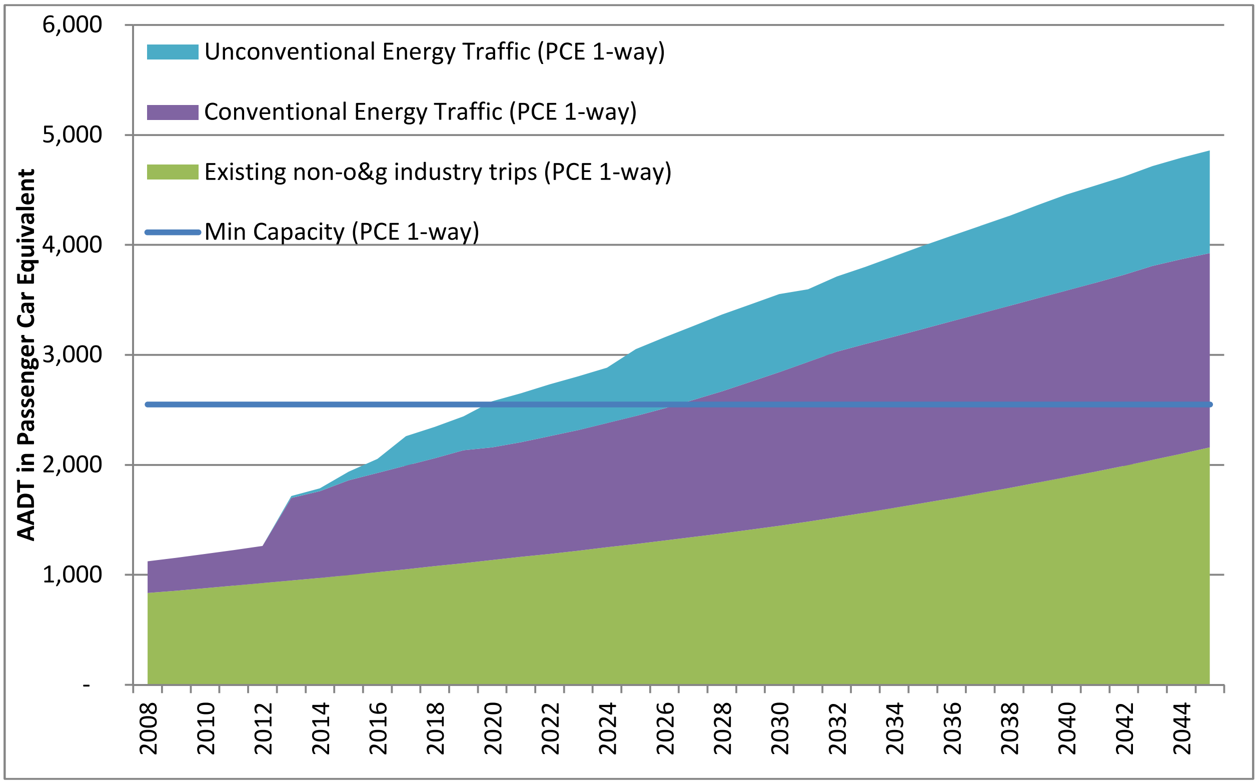
The difference is that there is a large capacity increase from 4,650 to 5,650 one-way passenger car equivalents expected in 2030, which will reduce the potential output gap. Despite the projected increase in capacity, there would still be a significant loss of conventional and unconventional production in the next 30 years without further capacity improvements.

Figure 36: Transportation Projection by Energy and Non-energy Trips – One-Way Trips from and to the West



The northbound traffic projection is summarized in Figure 37. Although it would increase at a slower rate than westbound or eastbound traffic, northbound traffic is still expected to reach roadway capacity within 10 years, based on the median projection. Traffic is projected to reach over 4,500 AADT, or nearly double the projected capacity, by the end of the study period.

Figure 37: Transportation Projection by Energy and Non-energy Trips – One-Way Trips from and to the North



Unlike for the other directions, southbound traffic is not expected to exceed capacity based on the median projection, within the study period. The relatively small number of newly generated oil and gas trips to and from the south is not expected to put strain on the southbound routes over the next 30 years. By 2042, the expected total AADT will be about 3,000 passenger car equivalents, well within the capacity of 3,500 AADT.

Figure 38: Transportation Projection by Energy and Non-energy Trips – One-Way Trips from and to the South

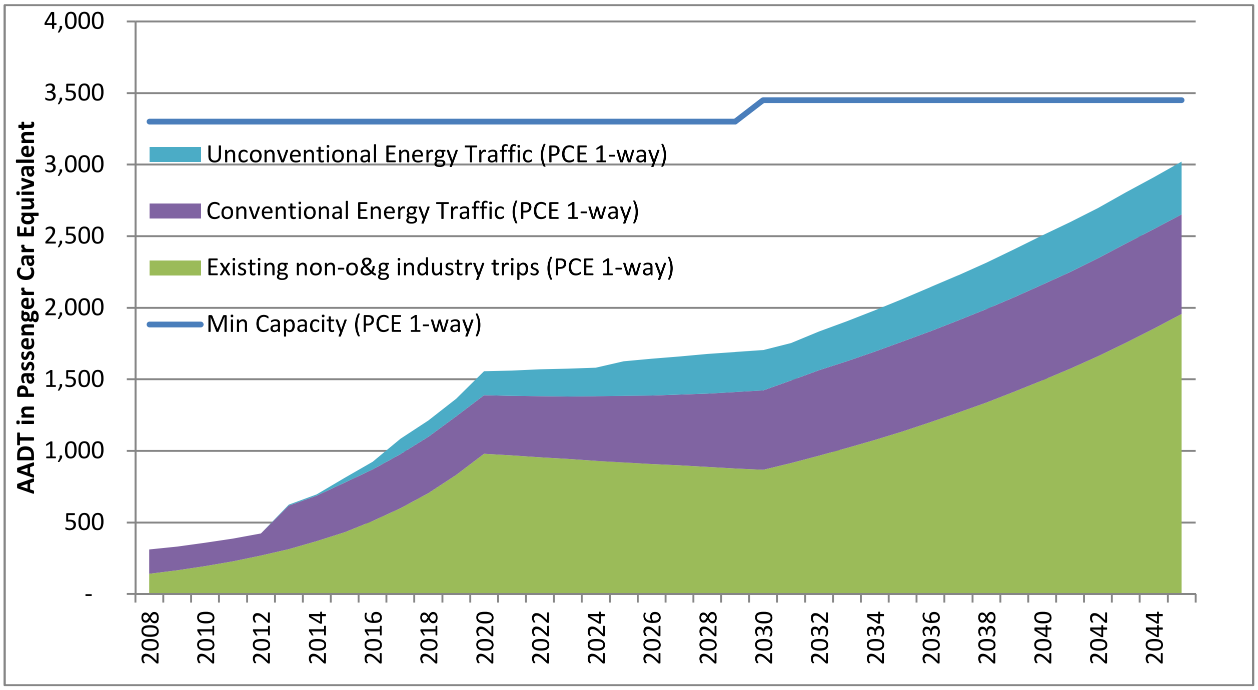
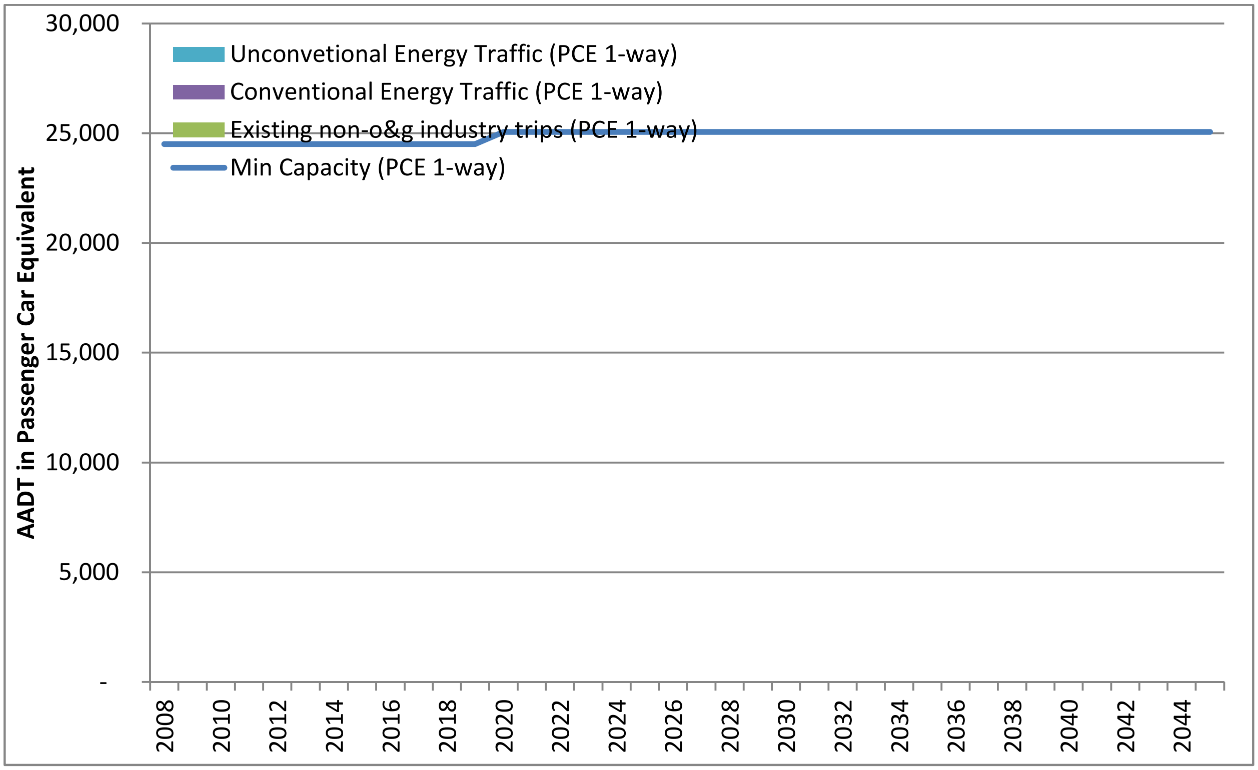


Figure 39 provides projections of traffic on local roads in the Uinta Basin. Local roads are expected to have a very significant increase in oil and gas energy-related trips and to reach the minimum capacity by 2024. Although there is a small expected increase in capacity from 24,500 to 25,050 combined AADT in passenger car equivalents, the overall traffic is expected to grow beyond capacity, starting in 2024.

Figure 39: Transportation Projection by Energy and Non-energy Trips – One-Way Trips from and to Local

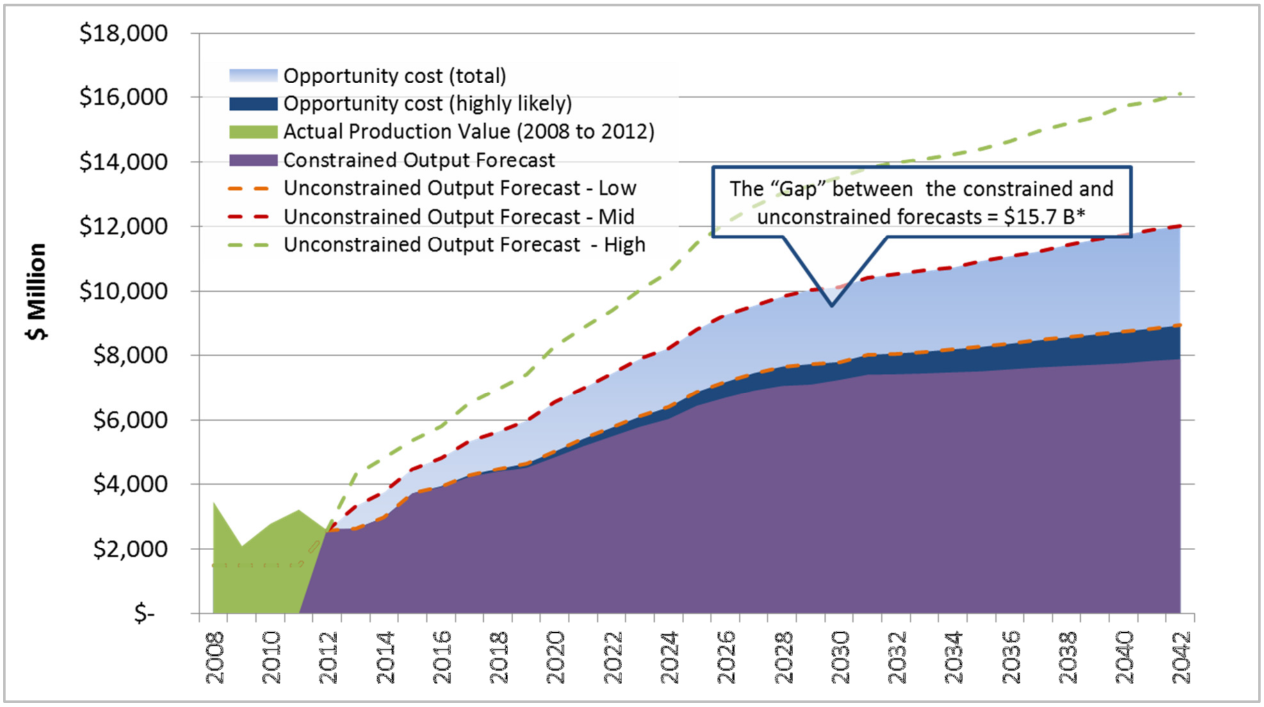


7.6.2 Production Gap Estimation Results

As shown in the traffic projection simulation results, many of the transportation corridors serving the Uinta Basin will face severe constraints given the projection of oil and gas–related traffic. The current constraints therefore reduce the overall oil and gas production opportunity for the Uinta Basin and the State.

Figure 40 depicts the difference between the transportation-unconstrained and -constrained forecasts given existing and planned transportation network capacity. The figure presents low, mid, and high unconstrained output as three sets of dotted lines. The median constrained forecast is represented by the graph colored in purple area. The production gap is represented by the white, light blue, and dark blue areas. The total median gap in non-discounted term amounts to $29.0 billion. Discounted at 3%, the present value of the total gap is $15.8 billion in 2012 dollars. The interpretation of the gap assessment is that, without improvements to address traffic capacities that are constraining oil and gas development, the State will forego oil and gas production that would otherwise occur, equivalent to $15.8 billion in present-value terms.

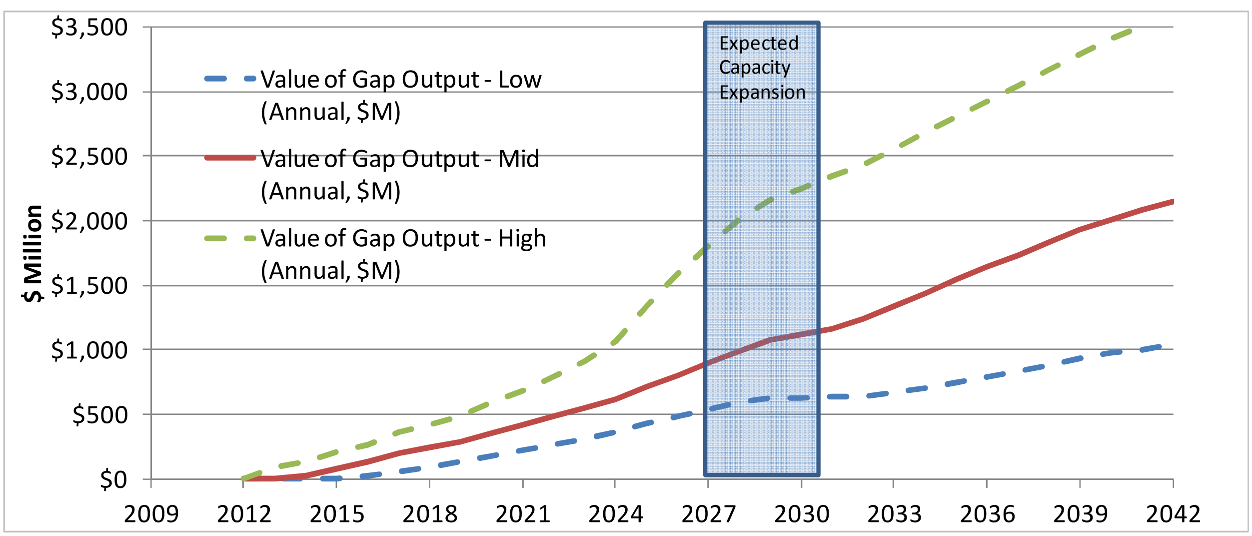
Figure 40: Output Gap in 2012 Dollars, 2013 to 2042



Note: Present value at 3% discount rate, future value equals $29.0 billion.

Figure 41 focuses on the output gap only. The value of the gap by year was forecasted and graphed at 10th, 50th, and 90th percentiles. There is slight halt in the growth of the gap output from 2030 to 2031 because westbound routes are expected to have significant increases in their combined capacities.

Figure 41: Output Gap by Year, 2012 to 2042

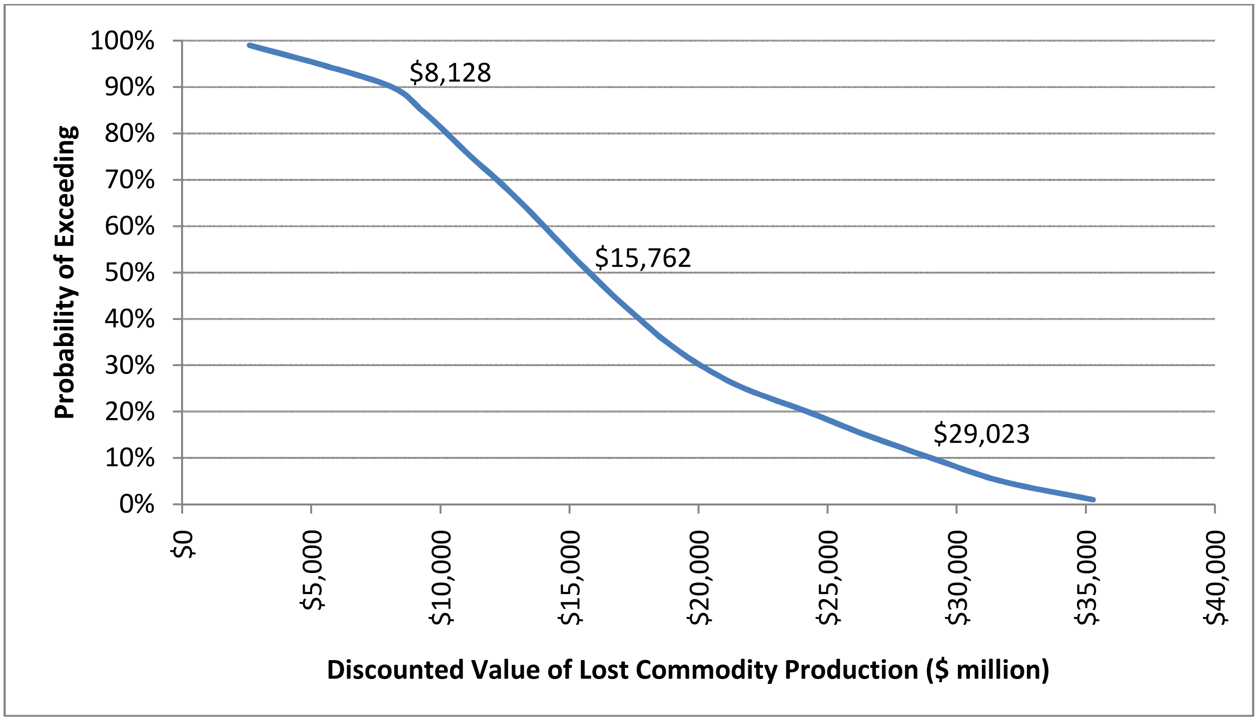


Valuation of the gap at the 10th, 50th, and 90th percentiles is provided in Table 46 and presented graphically in Figure 42. The median present value of the production gap is $15.8 billion. At the low end, the expected present value is $8.1 billion, which means that there is 90% probability that the production loss is greater than $8.1 billion. At the 90th percentile, the present value of the gap is $29.0 billion.

Table 46: Non-discounted and Discounted Production Gap due to Transportation Constraints in the Uinta Basin - 2013 to 2042

Forecast Level	Total (Undiscounted)	Present Value at 3%
Low	$14.7 billion	$8.1 billion
Mid	$29.0 billion	$15.8 billion
High	$52.8 billion	$29.0 billion

Figure 42: Results of Risk Analysis of Discounted Value of Production Gap

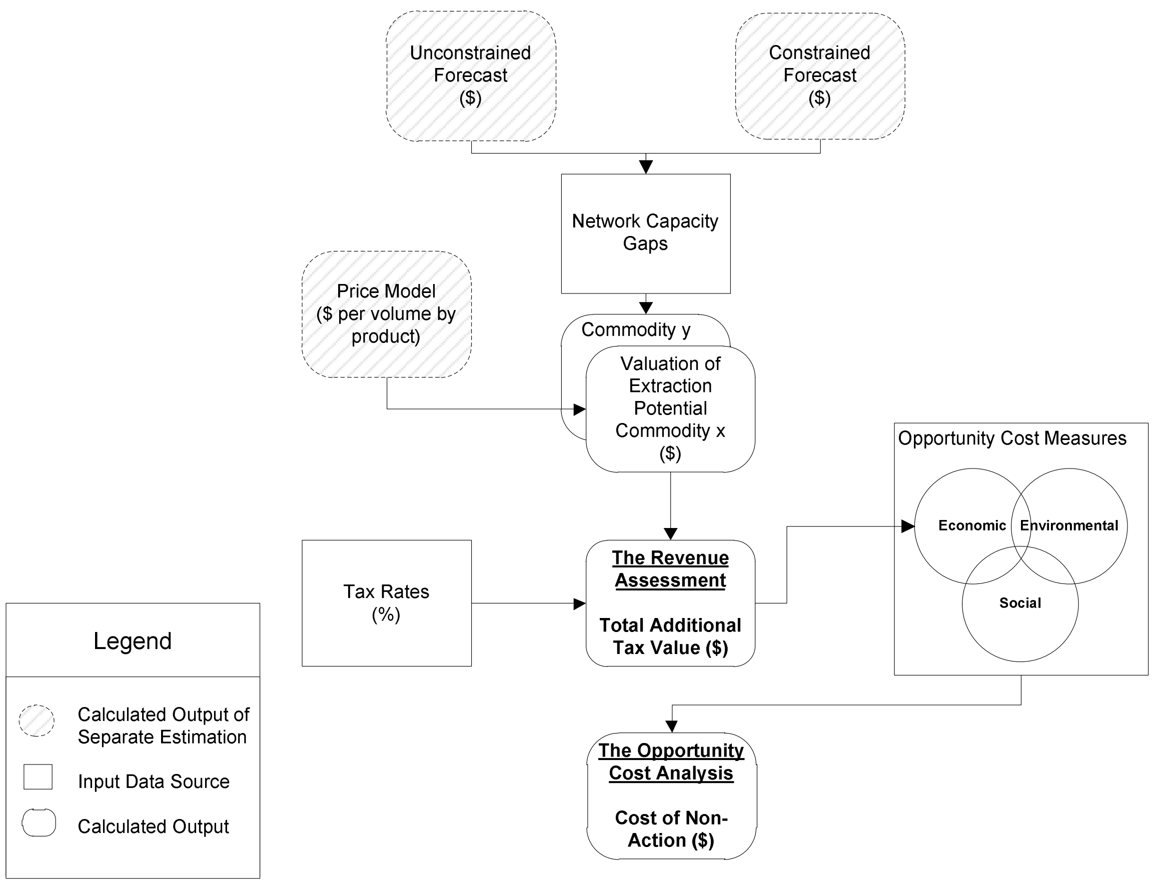


The next section investigates the tax revenue effects and the other opportunity costs of failing to address the transportation constraints identified in the constrained forecast.

8 Regional Opportunity Cost Estimation

Once the gap between the constrained and unconstrained forecasts is identified, quantified, and valued, a further estimation of the opportunity cost of failing to address that gap must be completed. The valuation of the gap is the value of the lost energy production, which is estimated at the market price of the product that is not extracted solely due to limitations in transportation capacity. Further analysis estimates what this value of lost production would have generated in taxes and royalties. These valuations, however, do not represent the full opportunity cost of not addressing the transportation constraints. Additional opportunity costs include the economic activity that additional energy production would generate throughout the economy, as well as the environmental and social consequences of supporting additional production and traffic. On the economic activity side, it is likely that additional production would encourage a growth of overall economic activity in the region. The social effects and environmental consequences of added production could be positive or negative, depending on the production technologies, traffic levels, and speeds of traffic once the constraints are alleviated. The opportunity cost assessment measures all of these issues, though readers should note that not all elements of the opportunity cost assessment can be fully measured in advance of identifying specific alternatives to network improvements. Figure 43 depicts the structure and logic of the revenue and opportunity cost assessments.

Figure 43: Structure and Logic of the Revenue and Opportunity Cost Assessments



The approach to quantifying the opportunity cost of the existing transportation capacity limitations is based on a valuation of the effects of the differences between outcomes in the constrained and unconstrained output scenarios. We relate these to a sustainable return on investment approach by considering benefits and costs within each dimension of the triple-bottom-line approach (economic, social, and environmental). The impact categories included within those dimensions represent impacts that are additive in the calculation of opportunity as well as those that are transfers within a public benefits framework, such as taxes and royalties.

The triple-bottom-line approach focuses on multiple metrics of benefit and cost in three dimensions:

- **Economic benefits and costs** are changes in the real economy, which create real value, but which may not necessarily be direct financial impacts. These include changes in employment, productivity, wages and salaries, prices and purchasing power, corporate profits, and government tax and royalty revenue. Here a distinction needs to be made between measures of economic impacts and changes in public welfare (public value) associated with those impacts. A good illustration of this distinction is in relation to job creation. An assessment focusing exclusively on the real economy (an economic impact analysis) would estimate the total number of jobs associated with a project or initiative and would report the labor income generated as a positive economic impact. In a public value assessment, on the other hand, employment is a welfare gain only to the extent that workers would be persistently unemployed otherwise or employed in a lower-productivity activity. For the purpose of measuring the opportunity cost of the transportation constraint, we measure the two-county and statewide macro-economic impacts (including, taxes, jobs, income, and output). These should not be confused with (or combined with) net public benefits, which consist of truly incremental economic, environmental, and social benefits and costs and are also measured under the economic evaluation. This portion of the economic evaluation focuses on specific, attributable transportation benefits to residents and businesses in the Uinta Basin area to determine whether the net public value of investments required for alleviating the transportation constraints justifies potential costs.[44]
- **Environmental benefits and costs** include a variety of impacts (such as greenhouse gas emissions, particulate emissions, etc.) resulting from production growth—from the extraction, processing, storage, and transportation of additional energy resources (relative to the constrained forecast).
- **Social benefits and costs** are impacts on people. These include changes in standards of living, mobility, and health.

Table 47 below provides examples of effects considered under each dimension.

[44] As with many of the effects and benefits described in the opportunity cost assessment, these can only be indicative only in Phase 1. More concrete evaluation of effects becomes possible when specific improvements are identified.

Table 47: Effects Considered in This Study by Dimension

Dimension	Description	Examples
Economic	Effects on businesses and the economy	• Net tax from energy production • Spending on goods and services in related industries • Employment of otherwise unemployed or under-employed residents • Reduced travel costs for local residents, visitors, and businesses • Improved travel conditions for local business and residents
Social	Effects on people and communities	• Safety of the transit of goods and people • Job creation and household income • Health effects of changing emissions levels • Impact of new development and infrastructure on cultural resources
Environmental	Effects on the planet and the natural environment	• Emissions from roadway traffic • Emissions from infrastructure development • Effects on water quality • Potential for land degradation Land Degradation • Emissions and other impacts from addition oil and gas extraction activity

The following sections look at the currently quantitatively measurable metrics for each of the triple-bottom-line approach dimensions in more detail.

8.1 Economic Effects

The assessment of the economic opportunity costs is based on an assessment of the effects on business and the economy of the potential additional energy product extraction if the transportation constraint is removed. The economic dimension of the opportunity cost assessment consists of three components:

1. Potential tax revenues
2. Macroeconomic effects (jobs, output, and labor income)
3. Transportation system user costs savings

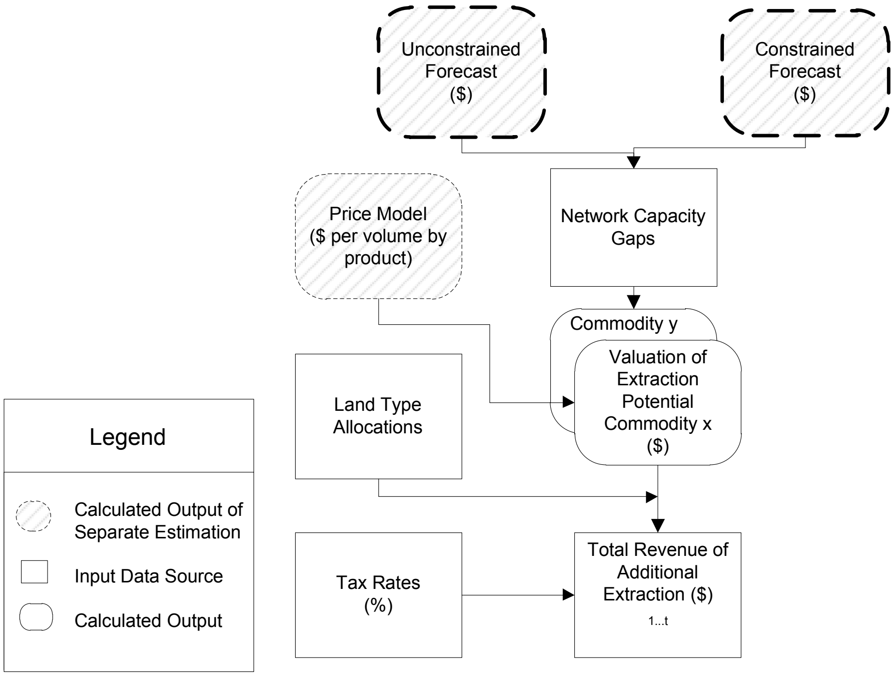
Each of these is discussed and estimated below. Readers should note that, while these three components are not necessarily additive (they each reflect an aspect of the economic opportunity costs, but in some ways might be overlapping), we have taken care to isolate out the incremental values under each component that can be summed to a total economic opportunity cost. This total economic opportunity cost is quantified at the end of this section.

8.1.1 Potential Tax Revenue Assessment

The revenue effects model estimates the tax-generation potential of the gap between the constrained and unconstrained forecasts. This section reviews the modeling approach, the revenue rate estimates, and other data and assumptions to be applied in the analysis.

The potential revenue forecast is an estimate of the State and local tax revenue lost should transportation constraints reduce the potential extraction activity in the Uinta Basin. Based on the constrained forecast, which values the lost commodity production, the potential revenue is valued based on the identified tax and royalty rates. The relationship between these calculations is provided in Figure 44. Certain rates, particularly royalties, only apply to certain portions of the total output—in this case, output on federal land. The revenue model accounts for this by segmenting the production into land types: federal (BLM), State, private, and tribal.

Figure 44: Structure and Logic of the Potential Revenue Forecast



The type of land on which future activity will take place has a significant impact on revenues. Certain revenues, particularly royalties, only accrue on federal lands, and other local fund rates are specific to public or tribal lands.

Key Tax Revenue Estimation Data

Because tax rates and revenue rights depend on the ownership and designation of the land from which commodities are extracted, assumptions about the distribution of production across land types are a key factor in the tax revenue forecast. Estimates of allocation of resource extraction by land type are based on analysis of DOGM data for existing extraction. DOGM identifies the type of land that existing operational oil and gas wells are located on and the forecast assumes that the future distribution of extraction by land type will be similar. Information collected through the interview process indicates that producers are continuing to look at a variety of land types for future development. Table 48 describes the distribution of currently operating wells by land ownership. Table 49 describes the distribution of reserves by land type.

Table 48: Distribution of Currently Operating Wells by Land Ownership

Land Ownership	Gas Wells	Oil Wells	Total
Federal	56%	44%	52%
State	20%	6%	15%
Private	2%	27%	12%
Tribal	21%	24%	22%

Source: DOGM via UPlan
Note: Totals may not add up to 100 % due to rounding.

Table 49: Distribution of Reserves by Land Ownership

Land Ownership	Gas Reserves	Liquids Reserves	Oil Reserves
Federal	12%	12%	22%
State	21%	21%	28%
Private	26%	26%	19%
Tribal	40%	40%	31%

Source: DOGM via UPlan

Note: Totals may not add up to 100 % due to rounding.

Based on this information and input from stakeholders via the stakeholder review process, Table 50 describes the assumptions regarding land ownership applied to the tax revenue estimate.

Table 50: Assumed Distribution of Future Production by Land and Commodity Type

Land Ownership	Future Distribution of Land Ownership for Oil Production
Federal	44%
State	6%
Private	25%
Tribal	25%
Land Ownership	**Future Distribution of Land Ownership for Oil Production**
Federal	56%
State	20%
Private	4%
Tribal	20%

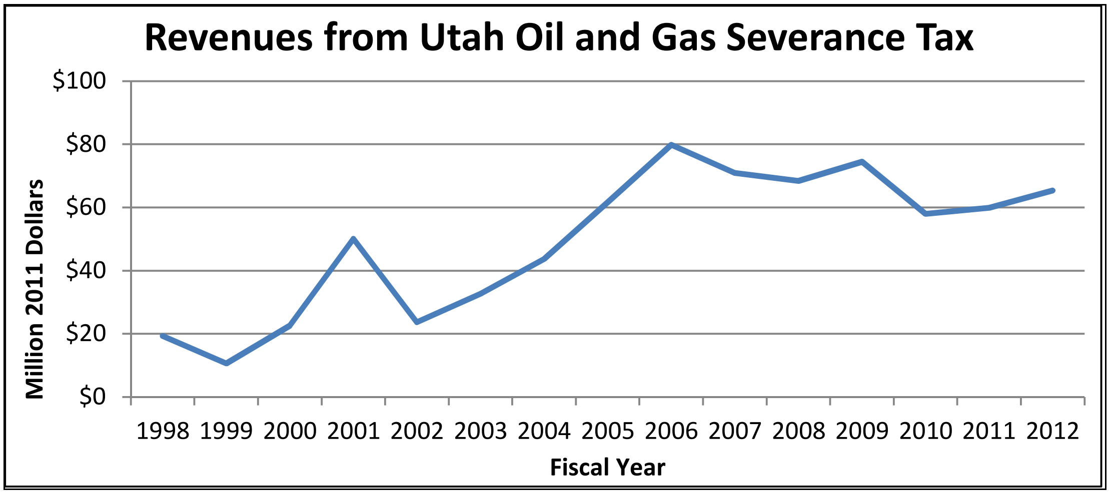
The other key variable in the tax revenue estimate is the rates for various taxes and fees on direct energy commodity production.

The Utah State Tax Commission and the Governor's Office of Planning and Budget regularly release data on various fees and state and local revenues generated by oil and gas extraction in Utah. Several state-level taxes and fees apply, including the oil and gas severance tax, which raised nearly $60 million in fiscal year (FY) 2011 from the production of oil, gas, and NGLs at a rate between 3% and 5%.[45] Revenues from this tax have risen threefold since 1998 but have remained flat since 2006. The State also imposes an oil and gas conservation fee, which brought in $5.8 million in restricted revenue[46] to the General Fund in FY 2011.

[45] No tax is imposed upon: (a) "stripper" wells—oil wells at less than 20 BOPD and gas wells at less than 60 thousand cubic feet per day; (b) the first 12 months of production for wildcat wells; (c) the first six months of production for development wells. Also, a 50% reduction in the tax rate is imposed upon the incremental production achieved from an enhanced recovery project.

[46] Restricted revenue funds have a legally designated purpose, in this case for specified education expenditures.

Figure 45: Growth in Revenues from Oil and Gas Severance Taxes, Utah Real ($ Million)



Source: HDR estimation from revenue data in 2012 Economic Outlook: Economic Report to the Governor of Utah series, Utah Governor's Office of Planning and Budget, January 2012, and Consumer Price Index – Urban Consumers, Bureau of Labor Statistics.

Income from increases in oil and gas producers in the state will also be impacted by significant increases in production. The State's corporate income tax is 5% of apportioned net income, with a $100 minimum tax per corporation. For tax year 2009, 141 mining entities filed returns and paid taxes of $20.5 million, which represented 13.3% of the total.

The State levies a state sales and use tax of 4.75%. Utah counties can also levy a 1% option of the local sales and use tax, as well as 0.25% optional sales and use tax.

Royalties are another significant revenue source. Oil and gas production royalties are negotiated and based on a percentage of gross from the site and are traditionally 12.5% of production. For wells and mines on federal lands, royalty payments are governed by the Mineral Lands Leasing Act and are paid to the Office of Natural Resources Revenue (ONRR), a unit of the U.S. Department of the Interior (previously the Minerals Management Service). Approximately 49% of these royalties are returned to the State.

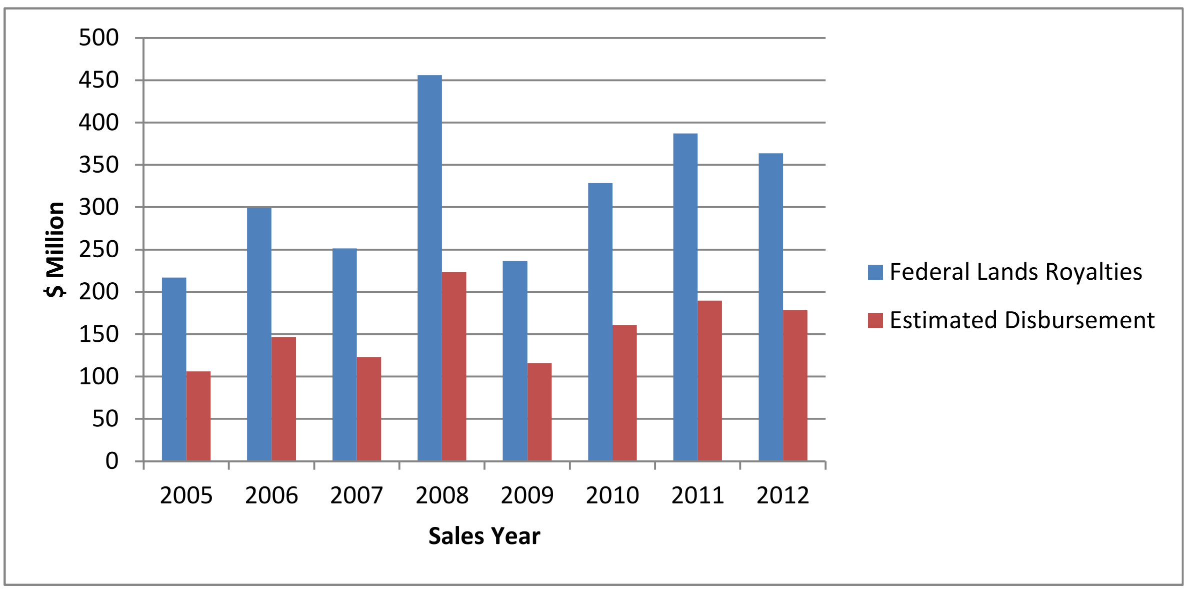
Table 51: Royalties by Mined Oil and Gas Products and Return Disbursements to the State of Utah - 2011

Product	Sales Value	Royalty/Revenue	Disbursement	Disbursements as % of Royalties
Condensate	$155,861,018	$19,389,801	$9,971,405	51%
Drip or scrubber condensate	$247,403	$30,925	$13,962	45%
Gas plant products	$307,137,773	$28,667,996	$13,241,799	46%
Oil	$684,740,233	$87,852,965	$44,780,738	51%
Processed (residue) gas	$929,638,042	$100,406,731	$50,910,355	51%
Unprocessed (wet) gas	$103,001,302	$11,366,621	$5,298,152	47%
Sum (oil and gas)	$2,180,625,771	$247,715,041	$124,216,412	50%
Reported total for all products	$2,513,561,015	$274,176,905	$149,439,229	55%
Percent of all oil and gas products in Utah	87%	90%	83%	—

Source: Office of Natural Resources Revenue[47]

Figure 46 presents the oil and gas royalties collected by ONNR and its predecessor agency, Minerals Management Service, for production on federal lands in Utah and the estimated disbursement based on that collection for the years 2005 through 2012.

Figure 46: Total ONNR Royalties for Mined Oil and Gas Products and Estimated Disbursements to the State of Utah, 2005 to 2012



Source: Office of Natural Resources Revenue

[47] http://www.onrr.gov/ONRRWebStats/StateAndOffshoreRegions.aspx?state=UT&yeartype=FY&year=2011&dateType=AY

Table 52 describes the current rates for various taxes and fees by commodity and land types.

Table 52: Current Tax, Fee, and Royalty Rates

State-Level Taxes and Fees	Current Rate	Source and Notes
Oil and gas severance tax – oil	3%–5%	Source: "Utah Oil & Gas Production Taxes Summary," Utah Division of Oil, Gas and Mining. https://fs.ogm.utah.gov/pub/Oil&Gas/Publications/Lists/prod_tax_sumry.PDF. Applies to wellhead/mine mouth revenue. Sliding scale, based on the value of oil produced and saved, sold, or transported from the field: (1) 3% of the value of up to and including the first $13 per barrel, and (2) 5% of the value from $13.01 and above per barrel.
Oil and gas severance tax – natural gas	3%–5%	Source: "Utah Oil & Gas Production Taxes Summary," Utah Division of Oil, Gas and Mining. https://fs.ogm.utah.gov/pub/Oil&Gas/Publications/Lists/prod_tax_sumry.PDF Applies to wellhead/mine mouth revenue. Sliding scale, based on the value of natural gas produced and saved, sold, or transported from the field: (1) 3% of the value up to and including the first $1.50 per thousand cubic feet, and (2) 5% of the value from $1.51 and above per thousand cubic feet.
Oil and gas severance tax – natural gas liquids	4%	Source: "Utah Oil & Gas Production Taxes Summary," Utah Division of Oil, Gas and Mining. https://fs.ogm.utah.gov/pub/Oil&Gas/Publications/Lists/prod_tax_sumry.PDF Applies to wellhead/mine mouth revenue. No sliding scale.
Oil and gas conservation fee	0.2%	Source: "Utah Oil & Gas Production Taxes Summary," Utah Division of Oil, Gas and Mining. https://fs.ogm.utah.gov/pub/Oil&Gas/Publications/Lists/prod_tax_sumry.PDF Applies to wellhead/mine mouth value of oil and gas produced and saved, sold, or transported from the field in Utah. Goes into the Oil and Gas Conservation Account.
State corporate income tax	5.0%	Source: Utah State Tax Commission, Annual Report Fiscal Year 2011–2012. http://tax.utah.gov/commission/reports/fy11report.pdf Revenue net of expenses and taxes (with a $100 minimum tax per corporation).
State sales and use tax	4.75%	Source: Utah State Tax Commission, Annual Report Fiscal Year 2011–2012. http://tax.utah.gov/commission/reports/fy11report.pdf Applies to "sales of tangible personal property made within the state… "
County and local taxes and fees	**Current Rate**	**Application**
Local sales tax	1.0%	Applies to the purchase price on the same transactions as the state sales and use tax.
County option sales tax	0.25%	Applies to the purchase price on the same transactions as the state sales and use tax.
Federal royalties	**Current Rate**	**Application**
Royalty	12.5%	On a per-contract basis.
Portion of royalties remitted to State of Utah	49.0%	Applies to total royalty revenue.

Table 52: Current Tax, Fee, and Royalty Rates

Royalties on State lands	Current Rate	Source and Notes
Royalty – oil	12.5%	Source: Utah Administrative Code R652-20-1000, Rentals and Royalties. For wells and mines on School & Institutional Trust Lands Administration (SITLA) land (about 1% of Uinta Basin area). Funds are restricted to the specified trusts.
Royalty – gas	12.5%	Source: Utah Administrative Code R652-20-1000, Rentals and Royalties. For wells and mines on SITLA land (about 1% of Uinta Basin area). Funds are restricted to the specified trusts.
Royalty – oil shale	5%–12.5%	Source: Utah Administrative Code R652-20-1000, Rentals and Royalties. 5% during the first 5 years of production and increasing annually thereafter at the rate of 1% to a maximum of 12.5%. For wells and mines on SITLA land. Funds are restricted to the specified trusts.
Royalty – oil (bituminous) sands	7%–12.5%	Source: Utah Administrative Code R652-20-1000, Rentals and Royalties. 7% during the first 5 years of production and thereafter may be escalated at the rate of 1% per annum to maximum of 12.5%. For wells and mines on SITLA land. Funds are restricted to the specified trusts.

Lost Tax Revenue Estimates

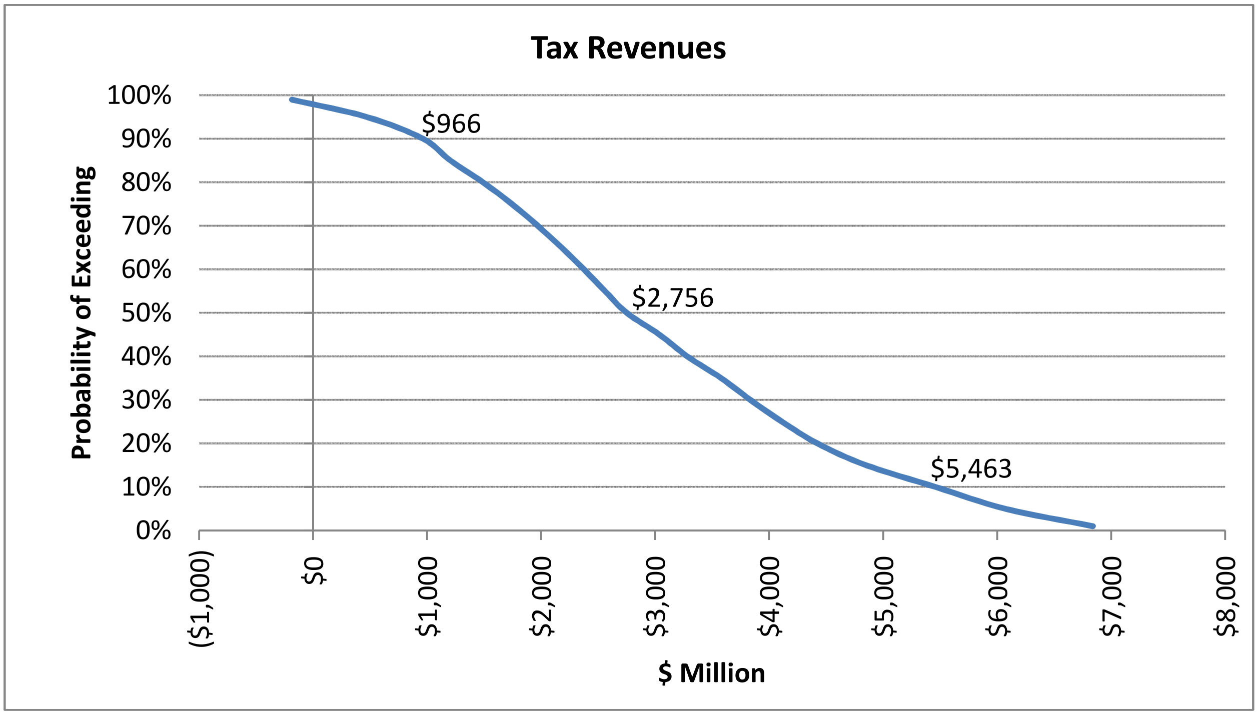
Estimation of the tax revenue equivalent value of the production gap between the transportation-constrained and -unconstrained forecasts indicates a sizable revenue loss. The revenue loss estimate focuses only on direct tax revenue from commodity production and not on ancillary revenue from associated activities, such as input purchase sales tax, income tax from persons employed by extraction firms, or corporate taxes on profits. The revenue loss estimate for the 30-year period is $5.4 billion, or a present value of $2.8 billion when discounted at 3%. The revenue loss by tax type is presented in Table 53.

Table 53: State and Local Tax Revenue Lost due to Transportation Constraints

Tax	Total Potential Revenue, 2013–2043 ($ Million)	Present Value at 3% ($ Million)
Oil and gas severance	$1,394	$714
Oil and gas conservation	$61	$31
Federal royalty remittance	$1,177	$604
State royalty (SITLA)	$689	$357
State sales tax	$1,625	$834
County and local option sales tax	$421	$216
Total	**$5,367**	**$2,756**

As with the gap estimate itself, the tax revenue loss estimate is also specified in a risk analysis simulation that results in an 80% confidence interval. The results of this risk analysis, presented in Figure 47, indicate there is a 90% probability of the loss exceeding $966 million in present-value terms and the potential that the loss could be as high as a present value of $5,463 million or higher.

Figure 47: Results of Risk Analysis of State and Local Tax Revenue Loss, Present Value ($ Million)



8.1.2 Macro-Economic Impact Assessment

Removing the transportation constraint in the Uinta Basin will not only unleash the production of crude oil and natural gas but will also generate further economic impacts in the Uinta Basin and beyond. The total economic impact of the oil and natural gas industry goes far beyond the gains in hydrocarbon production and employment that are experienced locally.

Methodology

This section introduces key concepts and metrics related to economic impact analysis and describes the methodology used to estimate the macroeconomic impacts associated with additional crude oil and natural gas production in the Uinta Basin.

Economic impact analysis involves the estimation of three types of effect, commonly referred to as direct effects, indirect effects, and induced effects. While direct effects refer to the initial shock or event to be analyzed (for example, increase in the oil and natural gas industry output), the indirect and induced effects refer to the additional rounds of expenditures and activities that are initiated throughout the economy as a result of the direct effect. The total economic impact is simply the sum of the direct, indirect, and induced effects. These effects can be characterized in terms of employment (full- and part-time jobs), labor income (including wages, salaries, and benefits), industry output (or total volume of sales), and tax revenue (at federal, State, and local levels). Each type of effect is described in in Table 54.

Table 54: Description of Macroeconomic Impacts

Type of Effect	Description
Direct effects	These are the effects directly attributed to the incremental extraction and production of oil and natural gas. For example, the production of an additional million barrels of crude oil will require the employment of a number of people (engineers, drill rig workers, etc.) who will receive wages and salaries in exchange for their work. It will also generate additional tax revenues in the form of federal mineral royalty payments.
Indirect effects	These are the effects attributed to the successive rounds of spending occurring throughout the supply chain as a result of the direct impacts. For example, the production of an additional million barrels of crude oil will require purchases from suppliers to the oil and natural gas industry (for example, manufacturers of drilling equipment), which in turn will generate additional expenditures (for example, purchases of steel). These additional expenditures will create jobs throughout the economy.
Induced effects	These are the effects attributed to the spending of earnings accrued to employees of the directly or indirectly affected industries. For example, the production of an additional million barrels of crude oil will result in the employment of people in the oil and natural gas industry supply chain (oil and gas extraction, drilling, drilling equipment manufacturing, etc.) who will spend a portion of their earnings on consumer goods and services (housing, food, health care, etc.). These additional expenditures will create jobs throughout the economy.

Note that the indirect and induced effects are often referred to as multiplier effects, since they can make the total economic impact substantially larger than the direct effect alone. Multipliers are often expressed in terms of employment. An employment multiplier measures the total increase in the number of jobs in the economy per new job created in a specific industry. Suppose the oil and gas extraction sector in Utah has a job multiplier of 1.4. This implies that every job created in that industry will generate an additional 0.4 job in the regional economy.

The economic impacts are estimated with the IMPLAN® system, an input-output-based regional economic assessment modeling system developed and maintained by MIG, Inc. Input-output (I-O) analysis is a means of examining relationships within an economy, both between businesses and between businesses and final consumers. It captures all monetary market transactions for consumption in a given period (typically a given year). IMPLAN® expands upon the traditional I-O approach to include inter-institutional transfers and thus can more accurately be described as a social accounting matrix (SAM) model.

The IMPLAN® system consists of a software package[48] and data files (readily available at the county, state, and national levels) that are updated every year. The IMPLAN® data files include transaction information (intra-regional and import and export) on 440 distinct industrial sectors (corresponding to four- and five-digit North American Industry Classification System [NAICS] codes) and data on 25 economic variables including employment, labor income, and industry output. For this study, the IMPLAN® system is populated with the most recent data available (2010) for the State and for Duchesne and Uintah counties. Outputs are generated at the state and county levels.

Estimation of Impacts

The analysis focuses on the operational impacts of the oil and natural gas industry and does not attempt to quantify the industry's capital investment impacts (for example, construction of oil fields). More precisely, the following two industries are considered in the analysis:

- Oil and gas extraction (NAICS 21111; IMPLAN® sector #20)

[48] IMPLAN® version 3.0 was used for this study.

- Drilling oil and gas wells (NAICS 213111; IMPLAN® sector #28)

The difference in oil and natural gas production value between the unconstrained and constrained forecasts is used to estimate the direct impacts. All backward-linked industries that provide the necessary inputs and services to these two industries (for example, support activities for oil and gas operations) are analyzed as part of the indirect effect estimation. A number of forward-linked industries (that is, industries that are further down the oil and natural gas industry supply chain, such as pipeline transportation and petroleum refineries, have also been identified).[49]

In addition, the following adjustments are made in the course of the analysis:

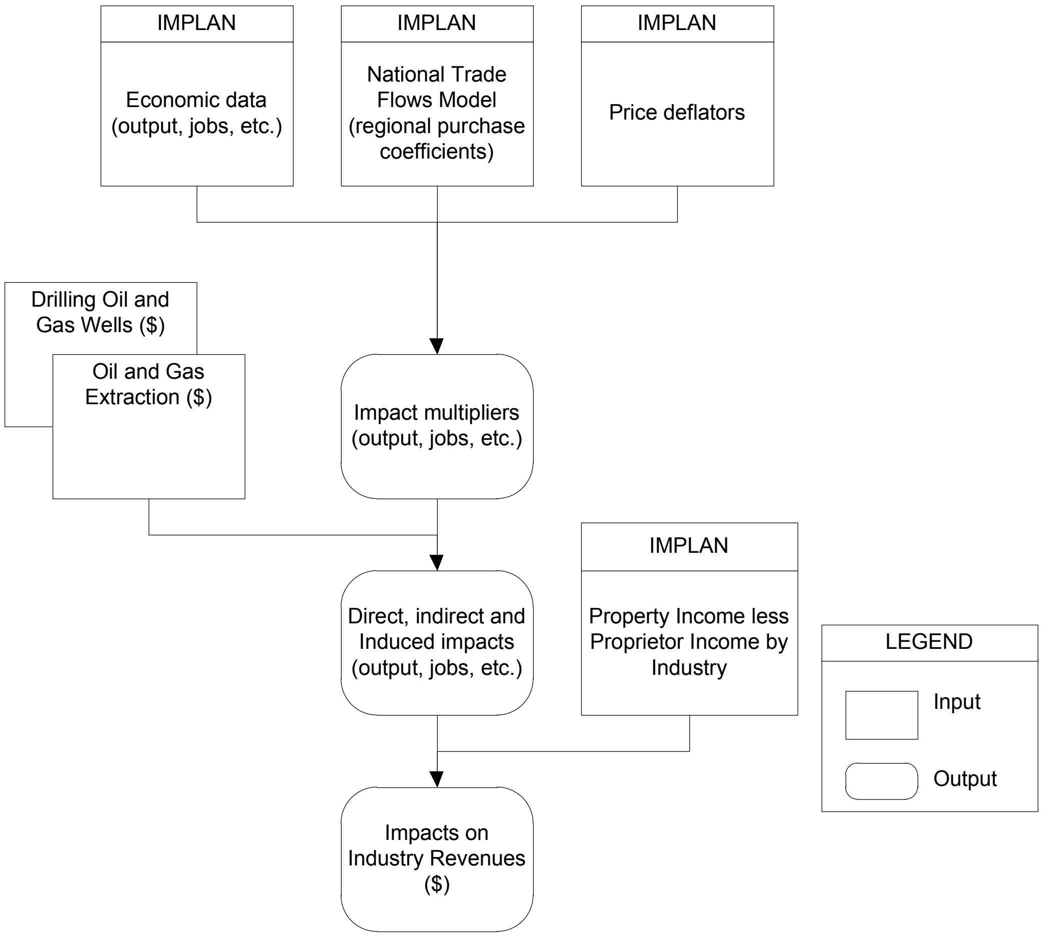
- Households are the only institution selected when building the model through multipliers in IMPLAN® (government and capital are typically not internalized). As a result, the induced effects are based on the income of households in the study area only.
- Type SAM multipliers, used for estimating indirect and induced effects, are modified with regional purchase coefficients (RPCs)[50] derived from the IMPLAN® National Trade Flows Model (NTFM) to ensure that any spending leaking out of the study area is not counted (for example, drilling machinery and equipment purchased by contractors might be manufactured outside of Utah).
- Since the original IMPLAN® data are for 2010, the impact analysis results are adjusted for inflation to be expressed in 2012 dollars.
- While the entire impact on output and job creation is of interest, it is not all additive to the tax revenue and microeconomic benefits also estimated in the economic opportunity cost assessment. However, a portion of that output impact represents corporate profits, capital consumption allowance, payments for rent, dividends, royalties, and interest income, which would be additive for the purpose of calculating a net opportunity cost. This portion is identified and separately catalogued as profits, rents, dividends, and private royalties.

Figure 48 below shows a graphical representation of the general process followed to conduct the economic impact analysis. Note that multipliers are obtained for as many industries (or activities to be modeled) and as many years of analysis as necessary.

[49] However, available information is deemed insufficient to estimate with a reasonable degree of confidence the impacts associated with these industries, within the scope of this study.

[50] RPCs represent the portion of the total regional demand that is met by regional production and attempt to account for cross-hauling—the importation and exportation of commodities from the same sector. All remaining demand is satisfied by imports, which provide no economic benefit to the region. In other words, RPCs filter out economic leakages from the region.

Figure 48: Assessment of Economic Impacts with IMPLAN®



Analysis Results

Consistently with the remainder of the study, the economic impacts are estimated within a risk analysis framework to account for uncertainties and risk events over the 30-year analysis period. Therefore, we are using annual risk-adjusted estimates of the oil and natural gas output gap to estimate the direct effects. Note, however, that the economic multipliers derived from IMPLAN® are fixed. The risk analysis results are discussed below.

Table 55 below shows that eliminating the transportation constraints would boost the oil and natural gas industry in the Uinta Basin, generating $45.8 billion in cumulative output value (or $15.8 billion in cumulative labor income) in that industry alone from 2013 to 2042. When the multiplier effects are taken into account, the total output impact amounts to $56.2 billion. Assuming an average term of employment of 10 years,[51] this translates into about 22,000 jobs. This additional economic activity would increase the tax base, resulting in increased federal, state, and local tax revenues. Indirect business taxes,[52] for

[51] Otherwise, employment impacts would have to be expressed in job-years. A job-year can be defined as one person employed for one year.

[52] Indirect business taxes include excise, sales, and property taxes, as well as fees, fines, licenses, and permits. However, they do not include employer contributions for social insurance and income taxes.

instance, are expected to reach $2.8 billion cumulatively by 2042. A summary of the impacts on the Uinta Basin economy is provided in Table 55.

Table 55: Cumulative Impacts of Foregone Oil and Gas Operations in the Uinta Basin (2013 to 2042) - $ Million

Impact Category	Direct	Indirect	Induced	Total
Output ($Million)	$45,825	$2,722	$7,621	$56,166
Value added ($Million)	$34,213	$1,496	$4,611	$40,329
Labor income ($Million)	$15,733	$940	$2,217	$18,887
Employment (FTE)	11,500	2,079	8,442	22,021

Notes: Full-time equivalent (FTE); gross domestic product (GDP). All dollar amounts are expressed in 2012 dollars rounded to the nearest million and are not discounted. Value added (equivalent to GDP) is a component of output, and the two should not be added. Employment impacts should not be interpreted as FTEs since they reflect the mix of full- and part-time jobs that is typical for each sector of the economy. Totals might not add due to rounding.

At the state level, the cumulative total output impact is estimated at $64.0 billion, a 14% increase over the two-county region estimate. In the same way, almost 28,000 jobs are expected to be created in Utah, a 22% increase over the two-county region estimate. Nearly half of these jobs would be created in the oil and natural gas industry (extraction and drilling), which corresponds to a more than doubling of (or 137% increase) employment in that industry alone.[53] A summary of the impacts on the State's economy is provided in Table 56.

Table 56: Cumulative Impacts of Foregone Oil and Gas Operations in Utah (2013 to 2042) - $ Million

Impact Category	Direct	Indirect	Induced	Total
Output ($Million)	$45,825	$5,881	$12,310	$64,016
Value added ($Million)	$34,213	$3,329	$7,324	$44,849
Labor income ($Million)	$15,733	$2,005	$3,983	$21,722
Employment (FTE)	11,500	3,866	11,436	26,802

Notes: Full-time equivalent (FTE); gross domestic product (GDP). All dollar amounts are expressed in 2012 dollars rounded to the nearest million and are not discounted. Value added (equivalent to GDP) is a component of output, and the two should not be added together. Employment impacts should not be interpreted as FTEs since they reflect the mix of full- and part-time jobs that is typical for each sector of the economy. Totals might not add due to rounding.

It is noteworthy that 72% of the total output impact is attributed to the oil and natural gas industry alone (direct effect), while only 9% is attributed to the supply chain effect (indirect effect). This implies that there is significant economic leakage (imports of goods and services from out of state) due to the relatively low geographical integration of the State's oil and natural gas industry supply chain.

In addition to the oil and natural gas industry, other sectors of the State's economy are impacted through the multiplier effects. Table 57 shows the top 10 industries impacted in Utah along with the associated multiplier effects in terms of employment and output. Note that industries are ranked according to their combined indirect and induced employment impact, since output per employee can vary substantially

[53] In 2010, the oil and gas extraction industry and the drilling oil and gas wells industry in Utah counted 4,862 workers (MIG, Inc., 2010 IMPLAN® data file for the State of Utah).

across industries.[54] Also, for the purpose of the analysis, it is again assumed that each job created has a typical term of employment of 10 years.

As reported in the table, food services and drinking places, as well as real estate establishments, are expected to contribute the most to job creation (1,221 jobs and 1,101 jobs, respectively), though most of it is the result of local spending on goods and services by households (induced effect alone). In fact, none of the top five impacted industries include key players in the supply chain of the oil and natural gas industry.

Table 57: Top 10 Industries Impacted in Utah (2013 to 2042)

Rank	Industry	Indirect and Induced Impacts	
		Employment (FTE)	Output ($Million)
1	Food services and drinking places	1,221	$650
2	Real estate establishments	1,101	$947
3	Offices of physicians, dentists, and other health practitioners	660	$701
4	Securities, commodity contracts, investments, and related activities	581	$601
5	Wholesale trade businesses	535	$724
6	Maintenance and repair construction of nonresidential structures	499	$642
7	Nondepository credit intermediation and related activities	471	$584
8	Architectural, engineering, and related services	442	$464
9	Private hospitals	387	$477
10	Retail stores; food and beverage	371	$203

Notes: Full-time equivalent (FTE). All dollar amounts are expressed in 2012 dollars rounded to the nearest million and are not discounted. Industries are ranked according to their combined indirect and induced employment impact alone. Employment impacts should not be interpreted as FTEs since they reflect the mix of full- and part-time jobs that is typical for each sector of the economy.

As discussed earlier in the report, the analysis spans 30 years and involves forecasting various factors that are subject to uncertainty. To account for that uncertainty, the economic impacts are generated in a risk analysis framework using Monte Carlo simulation techniques. Low and high estimates of the annual oil and gas output gap are derived by considering the lower and upper bounds of an 80% confidence interval estimated around the central predictions.

Table 58 summarizes the risk analysis results for the Uinta Basin. Economic impacts are reported at different probability levels: 10^{th} percentile (low), 50^{th} percentile (median or central estimate), and 90^{th} percentile (high). While there is only a 10% chance that the output impact will exceed $98.8 billion, there is a 90% chance that it will be at least $56.2 billion. In the same way, there is an 80% certainty that the total employment impact in the Uinta Basin will be between 12,000 and 39,000 jobs.

54 For instance, in 2010 the average output per worker in grain farming in Utah was $47, 417 only. On the other hand, high-value added industries such as construction machinery manufacturing or industries dealing with high value commodities such as transport by pipeline had an annual output per worker greater than $0.5 million (MIG, Inc., 2010 IMPLAN® data file for the State of Utah).

Table 58: Total Cumulative Impacts of Foregone Oil and Gas Operations in the Uinta Basin, Risk-Adjusted Results (2013 to 2042) - $ Million

Impact Category	Low	Median	High
Output ($Million)	$30,365	$56,168	$98,808
Value added ($Million)	$21,784	$40,320	$70,689
Labor income ($Million)	$10,212	$18,890	$33,223
Employment (FTE)	11,895	22,021	38,661

Notes: Full-time equivalent (FTE); gross domestic product (GDP). All dollar amounts are expressed in 2012 dollars rounded to the nearest million and are not discounted. Value added (equivalent to GDP) is a component of output, and the two should not be added together. Employment impacts should not be interpreted as FTEs since they reflect the mix of full- and part-time jobs that is typical for each sector of the economy. Totals might not add due to rounding. Low and high estimates reflect an 80% confidence interval.

Similarly, while there is just a 10% chance that the output impact will exceed $112.4 billion, there is a 90% chance that it will be at least $64.0 billion. And we can be 80% certain that the total employment impact in the Uinta Basin will be between about 14,500 and 47,000 jobs. A summary of the risk analysis results for the State is reported in Table 59.

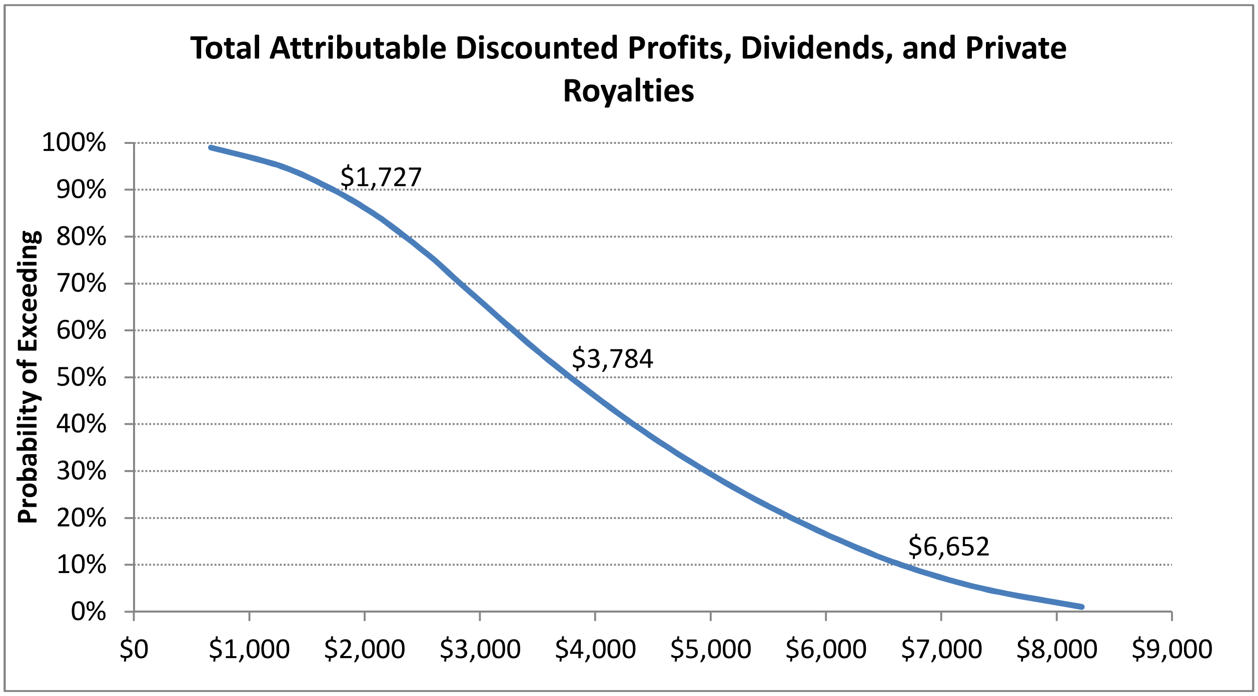
Table 59: Total Cumulative Impacts of Foregone Oil and Gas Operations in Utah, Risk-Adjusted Results (2013 to 2042) - $ Million

Impact Category	Low	Median	High
Output ($Million)	$34,604	$64,016	$112,432
Value added ($Million)	$24,256	$44,866	$78,869
Labor income ($Million)	$11,742	$21,721	$38,149
Employment (FTE)	14,454	26,802	47,026

Notes: Full-time equivalent (FTE); gross domestic product (GDP). All dollar amounts are expressed in 2012 dollars rounded to the nearest million and are not discounted. Value added (equivalent to GDP) is a component of output, and the two should not be added together. Employment impacts should not be interpreted as FTEs since they reflect the mix of full- and part-time jobs that is typical for each sector of the economy. Totals might not add due to rounding. Low and high estimates reflect an 80% confidence interval.

These statewide impacts include an identified portion representing profits, rents, dividends, and private royalties, which we identify separately so that they can be factored into the net opportunity cost assessment. Unlike the overall impact on output, these impacts are not duplicative or transfers of other benefits or effects included in the opportunity cost assessment. A risk analysis of these effects indicates that, within a confidence interval of 80%, the present value of the additive macro effects is between $1,727 million and $6,652 million with a median value of $3,784 million.

Figure 49: Results of Risk Analysis, Estimated Present Value of Additive Macroeconomic Effects, ($ Million)



8.1.3 Transportation User Economic Effects

Another aspect of the economic opportunity cost of the existing transportation constraints is the failure to realize certain benefits that would otherwise accrue to the direct users of the transportation system. Our analysis quantifies this opportunity cost by assessing the difference in aggregate user costs under the current transportation system and compares this to the hypothetical costs of a system with sufficient capacity to support all trips estimated under the transportation-unconstrained forecast. We therefore evaluate the benefits of capacity sufficiency. The principal categories of benefits considered in this component of the study are:

- Travel time savings
- Vehicle operating cost savings

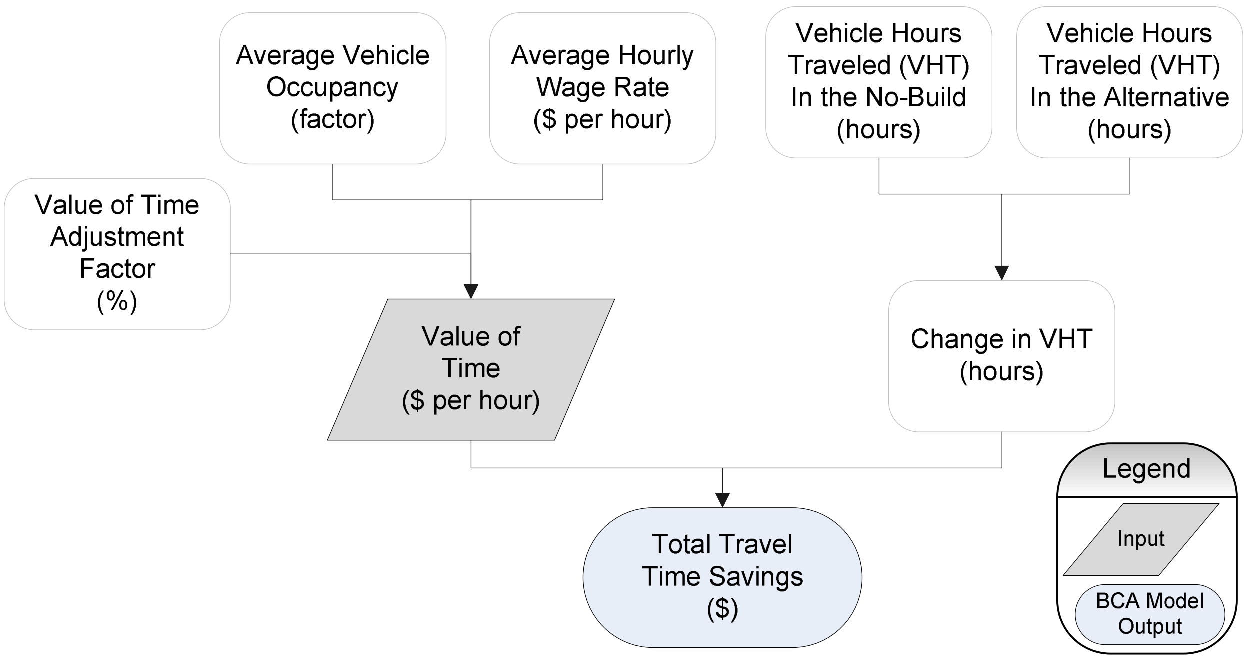
Methodology

Roadway User Time Savings

A major benefit from increasing capacity on constrained networks is usually derived from the increase in post-construction traffic speeds travelers enjoy as a result of the infrastructure project. This change in speed is reflected in the change in vehicle-hours traveled (VHT) and vehicle-miles traveled (VMT) for existing travelers between the base case (no-build) and the alternative and a higher overall speed for any potential new users of the transportation network. Due to an increase in average speed, drivers complete their trips in less time, thus resulting in an overall time savings measured in minutes or hours. These minutes or hours saved are then monetized via a value of time into an overall travel time savings.

Figure 50 illustrates the structure and logic diagram for estimating travel time savings. The value of time for trucks is accounted for using the Highway Economic Requirements System (HERS) methodology incorporating the Bureau of Labor Statistics estimate of an hourly wage rate for Utah truck drivers, the commodity fleet mix using payload values from the U.S. Bureau of Transportation Statistics (BTS), and input from experts at the November 30, 2012, RAP workshop. The value of time for passenger vehicles was calculated using U.S. Department of Transportation's (USDOT's) Transportation Investment Generating Economic Recovery (TIGER) Discretionary Grant program methodology for passenger vehicles and data on median household income from the U.S. Census.

Figure 50 : Structure and Logic Diagram for Time Savings

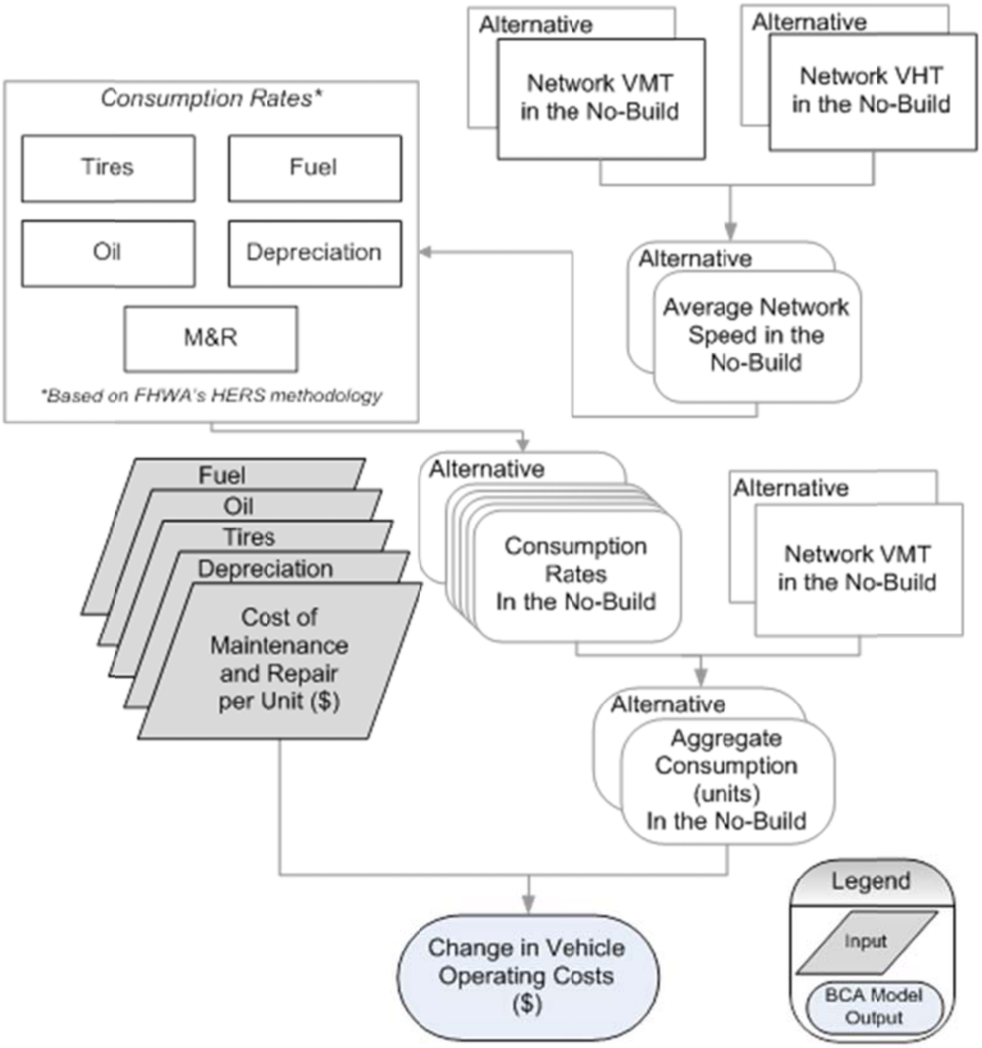


Vehicle Operating Costs

After a transportation-enhancement project is completed, resulting traffic flows can improve in ways that allow drivers to travel the same trip as before the project but do so with lower direct vehicle operating costs. Changes in travel speeds can increase fuel efficiency, reduce oil consumption, decrease wear and tear on the vehicle, and lower the deterioration rate of a vehicle's tires. Vehicle operating costs are generally the most recognized of user costs because they typically involve the out-of-pocket expenses associated with owning, operating, and maintaining a vehicle. The cost components of vehicle operating costs measured in this analysis are fuel consumption, oil consumption, maintenance and repairs, tire wear, and vehicle depreciation. The consumption rates for these costs are derived from average vehicle speed, combined with unit cost estimates to derive total out-of-pocket costs per mile and per trip. The methodology used to estimate consumption rates, as a function of speed, and the unit prices of these components are based on USDOT guidance for TIGER applications.

Figure 51 describes the structure and logic of the estimation of vehicle operating cost savings. All vehicle operating cost components, except for fuel, are based on the Federal Highway Administration's (FHWA's) Highway Economic Requirements System - State Version report (FHWA HERS-ST 2002). This is a tool used for evaluating the economic impact of highway programs on user costs. Values have been inflated to 2012 dollars using component-specific consumer price indices from the U.S. Bureau of Labor Statistics. Fuel price estimates are based on the EIA's Petroleum Administration for Defense District (PADD) 4 Gasoline and Diesel Retail Prices Monthly Price Series. PADD refers to specific geographic regions of the United States. PADD District 4 is also referred to as the Rocky Mountain Region and contains Colorado, Idaho, Montana, Utah, and Wyoming.

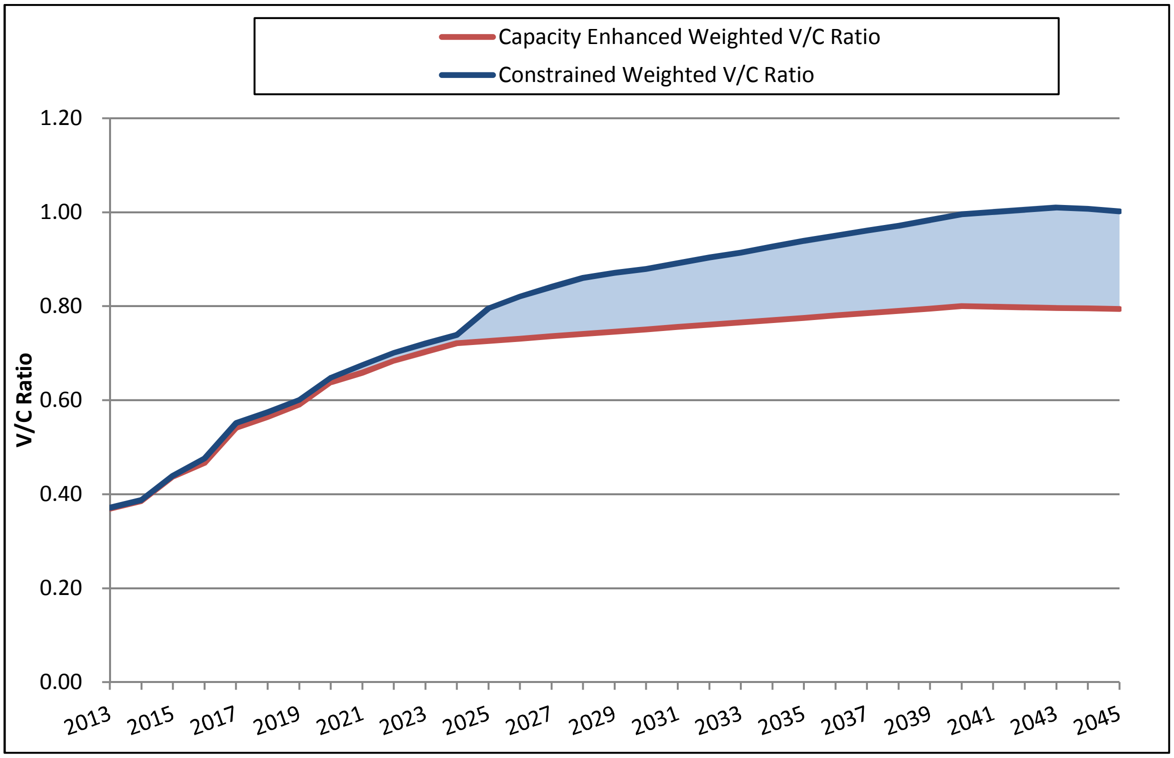
Figure 51: Structure and Logic Diagram for Vehicle Operating Cost Savings



Analysis Results

The main driver of the cost savings—travel time savings—stems from the fact that the roadway network reaches capacity in a short period of time, leading to high levels of congestion and low travel speeds. This is illustrated in Figure 52 below.

Figure 52: Comparison of Network Capacity between Constrained and Unconstrained Network



Notes: V/C Ratio is the ratio of vehicles to capacity, where 1.0 is maximum capacity and 0.8 is "safe" maximum capacity for roadways with heavy truck traffic.

Estimated benefits include travel speeds resulting from added capacity and reduced vehicle operating costs from improved travel speeds. As shown below, total user benefits have a 90% probability of exceeding $1.6 billion. The median or most likely value to be exceeded is $4.9 billion.

Table 60: Probability Distribution of User Benefits - Millions of 2012 Dollars

User Benefits Summary($Million)	Discounted at 3%		
	Low	Mid	High
Travel time savings	$1,150.2	$4,147.1	$11,197.3
Vehicle operating cost savings	$479.9	$795.4	$1,256.3
Total	**$1,630.1**	**$4,942.5**	**$12,453.6**

8.1.4 Summary of Economic Opportunity Costs

For the purposes of the UBETS opportunity costs assessment, the loss of economic value resulting from a shortfall in capacity is defined as the sum of the tax revenue, private profit, rents, dividends, private royalties, and user cost savings that would be enjoyed if transportation were not a constraint, but which will otherwise not materialize because of limitations to the current and currently planned network over the next 30 years. We calculated this loss separately for each of three categories:

1. State and local tax revenues
2. The portion of impacts on output representing profits, rents, dividends, and private royalties
3. User cost savings including time savings and vehicle operating cost savings

Table 61 presents the calculated median value in each of these categories. As indicated, the sum of these category values represents the present value of the total economic opportunity cost of transportation constraints in the Uinta Basin.

Table 61: Additive Economic Opportunity Costs by Category - 2013–2042

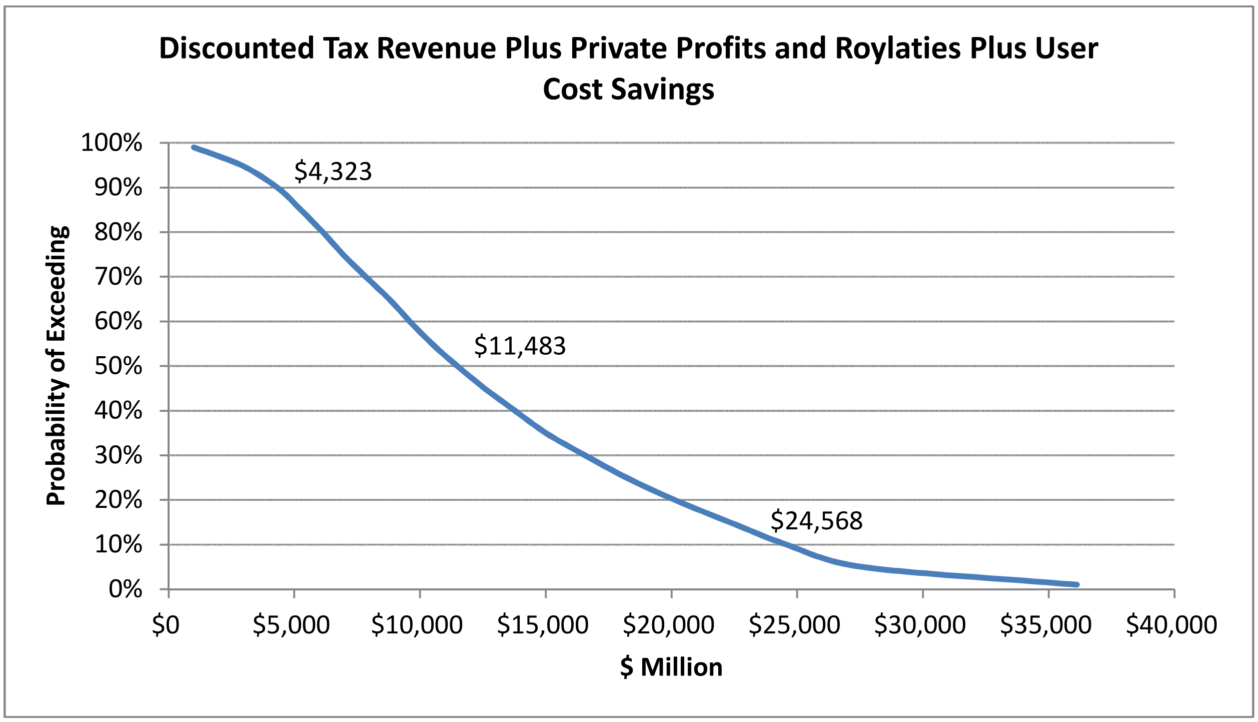
	Median Value (Discounted at 3%)
Tax revenues	
State and local tax revenue ($ Million)	$2,756
Additive macro effects	
Profit, rents, dividends, and private royalties Private Royalties ($ Million)[a]	$3,784
User benefits	
User cost savings ($ Million)	$4,943
Sum of additive benefit	**$11,483**

Note: Values are risk-weighted.

[a] Represents the portion of total output that is additional private citizen/corporate profit net of expenses and resource depletion.

Figure 53 presents the results of the risk analysis of the sum total present value of the economic opportunity cost. Within an 80% confidence interval, the total value of the economic opportunity cost is between $4.3 billion and $24.5 billion, with a median value of $11.5 billion.

Figure 53: Results of Risk Analysis of Additive Economic Opportunity Costs, ($ Million)



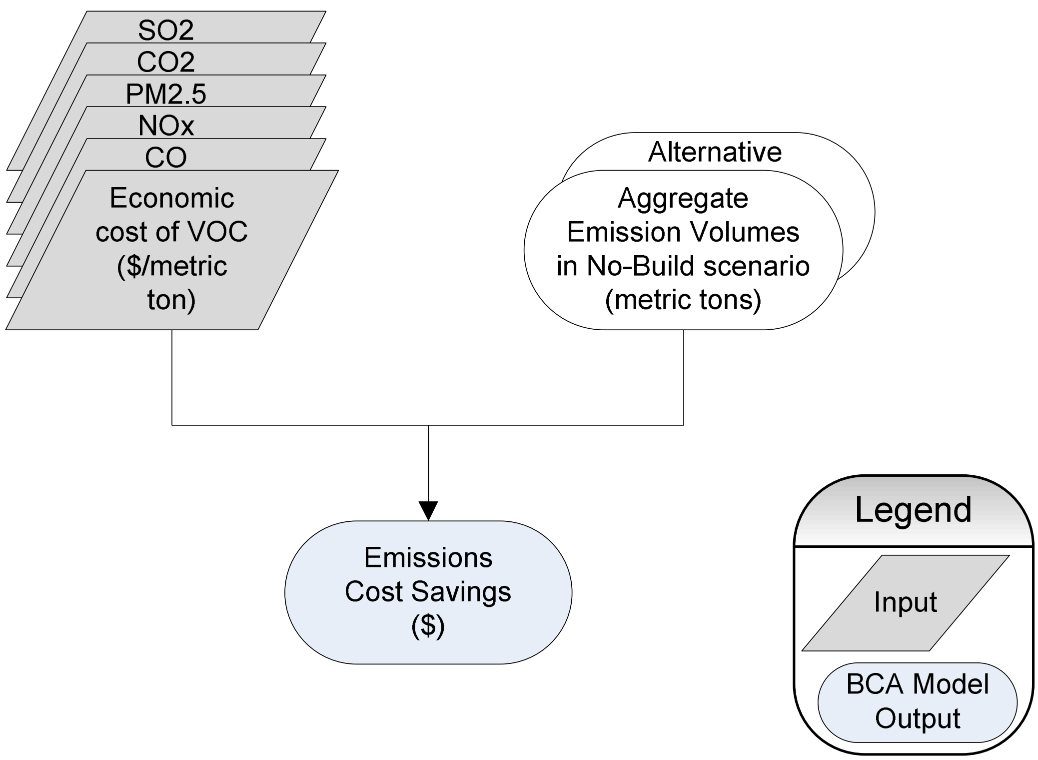
8.2 Environmental Effects

The main environmental impacts of vehicle use, exhaust emissions, and vehicle-generated noise can impose wide-ranging social costs on people, material, and vegetation. The negative effects of pollution depend on not only the quantity of pollution produced, but also the types of pollutants emitted and the conditions into which the pollution is released.

As with other travel costs savings, environmental cost savings are calculated based on the VMT and speed; therefore, the emission savings are calculated as the difference between the total cost of emissions emitted in the alternative case, and the total cost of emissions emitted in the base case. The difference is the net social benefits for emissions. Vehicle emission rates associated with carbon monoxide (CO), nitrous oxides (NO_X), volatile organic compounds (VOCs), particulate matter (PM), sulfur dioxide (SO_2), and CO_2 were estimated in EPA's MOVES vehicle emission modeling software by vehicle type mode for the project area.

Figure 54 describes the structure and logic of the estimation of vehicle emission impacts. The model uses estimates of the average cost of emissions by pollutant type to value changes in the expected rates of output given changes in the speed flow and traffic volumes resulting form added capacity.

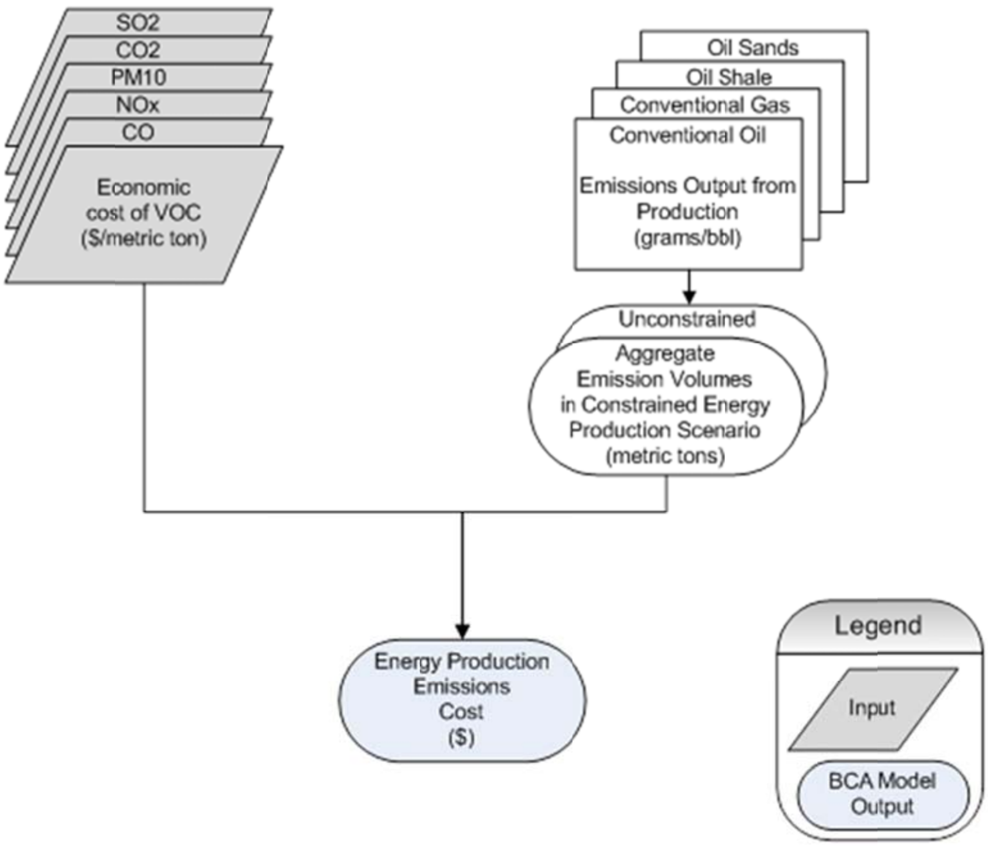
Figure 54: Structure and Logic Diagram for Vehicle Emission Cost Savings



In addition to emissions produced by cars and trucks, an increase in production volumes might also increase the generation of pollutants at extraction sites. This negative externality is also considered in the evaluation. As with the roadway emissions assessment, the negative effects of pollution depend on not only the quantity of pollution produced, but also the types of pollutants emitted and the conditions into which the pollution is released.

Emissions costs are calculated as the difference between the total cost of emissions emitted in the constrained case and the total cost of emissions emitted in the unconstrained case per well or mine site and the total number of wells and mines in the constrained and unconstrained forecasts. The difference is the net social cost of emissions. Figure 55 describes the structure and logic of the estimation of site emission cost savings. Well and mine site emission rates associated with CO, NO_X, VOCs, PM, SO_2, and CO_2 were estimated.[55]

Figure 55: Structure and Logic Diagram for Site Emission Cost Savings



The model uses estimates of the average cost of emissions by pollutant type to value changes in the expected rates of output given changes in the total production site generation.

Emission rates for conventional oil and gas production were derived from EPA estimates. Emission rates for oil shale and oil sands production were derived from information in the *Proposed Land Use Amendments for Allocation of Oil Shale and Tar Sands Resources Final Programmatic Environmental Impact Statement*. Research suggests that actual emission output for Utah oil sands surface mining might be lower than the numbers presented below, since they are derived from diatomaceous earth tar sands, while Utah has sandstone deposits.

Emission cost estimates were developed using guidance from USDOT's TIGER methodology. The values were developed from the *Final Regulatory Impact Analysis Corporate Average Fuel Economy for MY*

[55] Based on data in the September 2012 Proposed Land Use Amendments for Allocation of Oil Shale and Tar Sands Resources on Lands Administered by the Bureau of Land Management in Colorado, Utah, and Wyoming and Final Programmatic Environmental Impact Statement and An Assessment of the Environmental Implications of Oil and Gas Production: A Regional Case Study, September, 2008.

2012-MY 2016 Passenger Cars and Light Trucks, March 2011, and the *Interagency Working Group on the Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866*.

The cost of CO is deemed negligible and the values for CO_2 are derived from the social costs of carbon estimates in the above mentioned Executive Order 12866.

All values were inflated to 2012 dollars using the consumer price index (CPI) for all urban consumers from the U.S. Bureau of Labor Statistics. All values presented below are in terms of grams per unit of output. Negative externalities form pollution come from both vehicles and the energy production sites. Impacts from infrastructure development, extraction, processing, storage, and transportation of additional energy resources are included and result in a variety of impacts including the following:

- Greenhouse gas (GHG) emissions
- Changes in air quality
- Changes in water quality
- Impacts on species and biodiversity
- Impacts on land resources

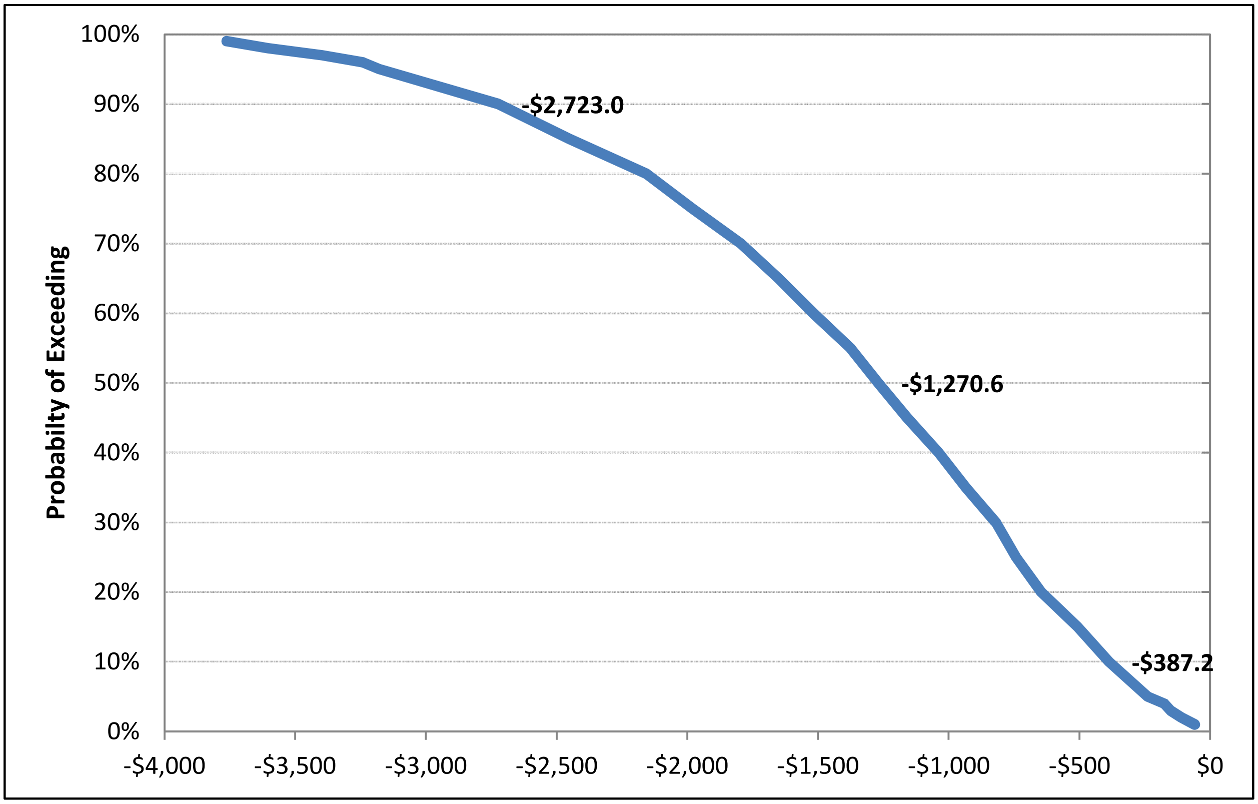
While the emissions increases resulting from more vehicles driving on the transportation network has a 90% probability of costing less than $322 million in environmental impacts, the most likely estimated cost of these emissions is $24 million.

With respect to the impacts from energy extraction, the environmental costs of site impacts have a 90% probability of costing less than $2.4 billion, with the most likely estimated cost totaling $1.3 billion.

Table 62: Environmental Impacts - Millions of 2012 Dollars

User Benefits Summary ($ Million)	Discounted at 3%		
	Low	Mid	High
Vehicle emissions	–$321.5	–$24.3	$263.6
Site impacts	–$2,401.4	–$1,246.3	–$650.8
Total	–$2,722.9	–$1,270.6	–$387.2

Figure 56: Risk Analysis of Environmental Impacts, Discounted at 3%, ($ Million)



8.3 Social Effects

Social benefits and costs are impacts on people. These impacts include changes in standards of living, educational attainment, health, and mobility. The social benefits of an expansion of oil and gas production in the Uinta Basin depend on how energy revenue "rents" are distributed between members of society. That distribution will be influenced by both market forces and government policy. Several categories of social impacts were considered during the course of the Phase 1 study.

Initial evaluation of potential social impacts was conducted during stakeholder workshops. Table 63 describes the initial evaluation by effect.

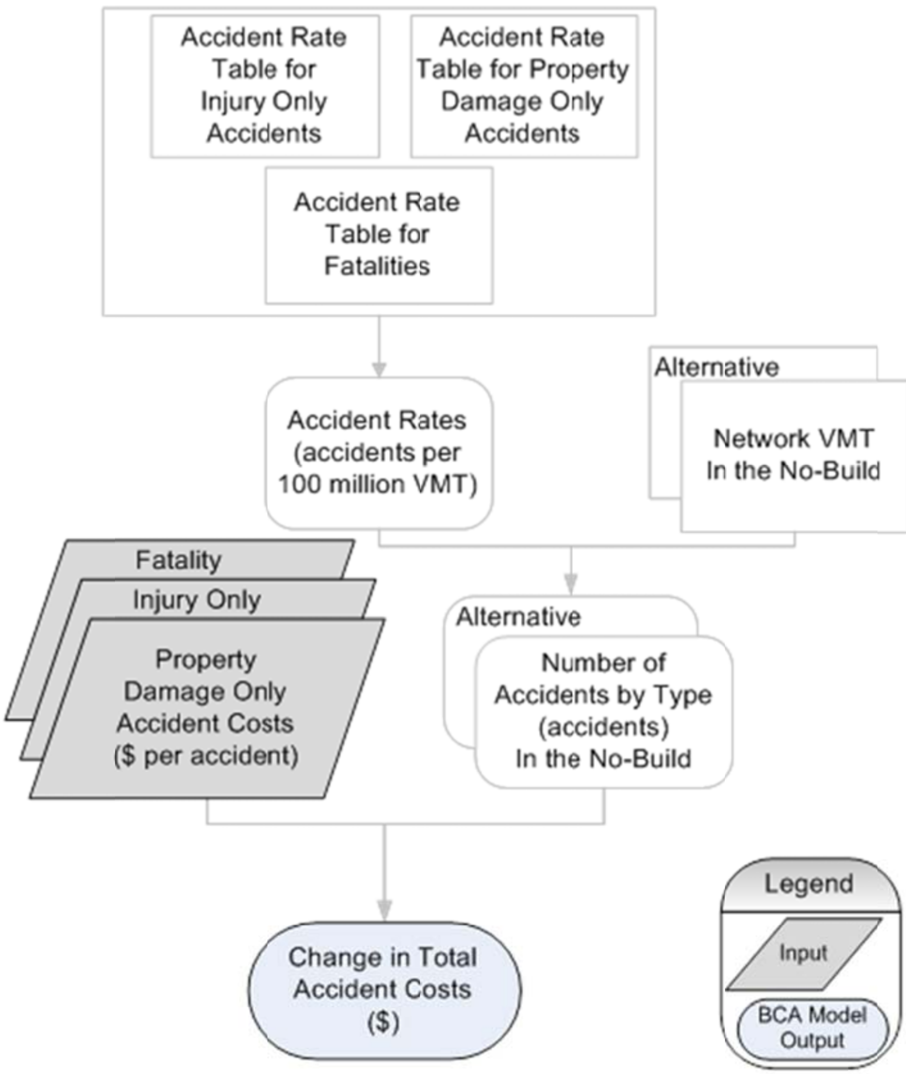
Table 63: Summary of Potential Social Effects of New Development

Potential Effect	Description
Training and skills development opportunities	Construction and operation of new infrastructure will require trained personnel and will allow an opportunity to develop new skilled trade and service workers.
Potential increase in the provision of public good and social programs	Increased property and income tax and increased state royalty collections could generate added funding for local services.
Health effects of potential oil spills	Increased transportation of oil could increase the risk of oil spills and the adverse impacts that oil spills could have on human health.
Infrastructure safety risks	Operation of new infrastructure used to extract unconventional resources could increase the likelihood of safety risks such as explosions, fires, etc.
Impacts of infrastructure development on heritage, archaeological, and cultural resources	Infrastructure development could impact heritage, archaeological, and/or cultural resources. In particular, future develop could impact natural resources and habitats of value to residents and visitors.

Of these, quantified (and monetized) values of expected impacts were limited to roadway safety effects. Further estimation of quantified effects will be necessary if an investment program is pursued.

Safety is a significant component of travel user cost. Highway safety represents a principal economic factor in the planning of roads as well as an important indicator of transportation efficiency. Outside the economic context, highway safety is often the object of public concern and a leading social issue. The accident cost model component is based on accident rates developed from historical data. Incident rates, in the form of fatalities, injuries, and property damage accidents, when combined with their associated costs, are turned into an accident cost. Total accident costs are then compared between the no-build base case and the alternative. Figure 57 illustrates the structure and logic diagram for accident cost savings.

Figure 57: Structure and Logic Diagram for Accident Cost Savings



Changes in accident costs, like other variable costs, are dependent on changes in VMT. The change in VMT is a function of the change in the number of vehicles on the road. Using the AADT estimates under the constrained and unconstrained transportation network scenarios, accident rates for fatal, injury, and property-damage-only (PDO) accidents, on a per mile basis, are multiplied by the VMT in the alternative and no-build scenario. Safety benefits are calculated as the difference between the total cost of accidents under the constrained and unconstrained transportation network scenarios

Costs associated with each type of accident are derived from USDOT guidance on the value of statistical life from the TIGER methodology guidance, which is based on the National Highway Traffic Safety Administration's *The Economic Impact of Motor Vehicle Crashes 2000* (May 2002).

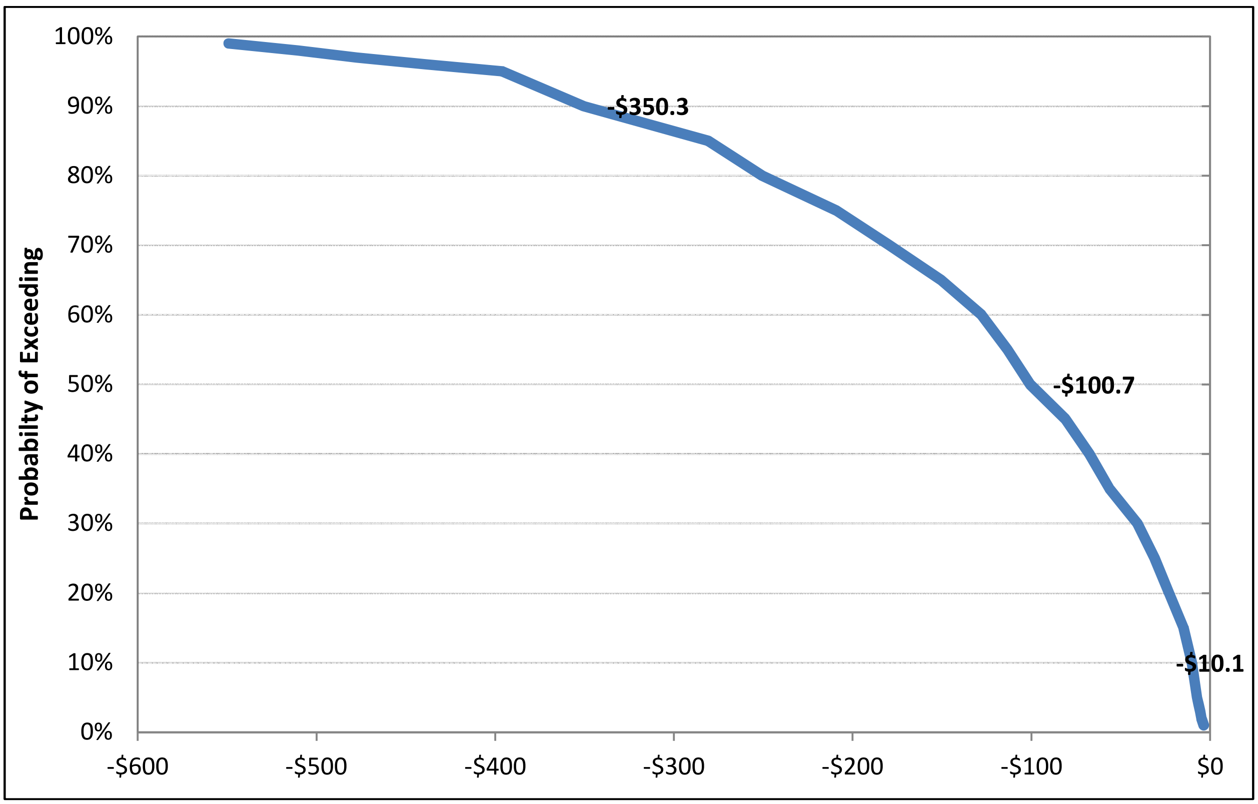
While improving capacity constraints will allow more vehicles to use the transportation network and travel at higher speeds, the increased travel volumes will result in higher accident probabilities and resulting costs. Due to the preliminary nature of the public benefits analysis, this would hold true if we assume that the accident rate between scenarios does not vary.

However, improved facilities and reduced crowding could have a safety improvement effect not included in this quantitative analysis. Based on the projected increases in traffic due to network capacity expansion, there is a 50% probability that costs will total $100 million.

Table 64: Safety Impacts, Millions of 2012 Dollars

Societal Summary ($ Million)	Discounted at 3%		
	Low	Mid	High
Safety impacts	-$350.30	-$100.70	-$10.10

Figure 58: Risk Analysis of Safety Impacts, Discounted at 3%, ($ Million)



8.4 Summary of Opportunity Cost Findings

The opportunity cost analysis of transportation constraints in the Uinta Basin follows a triple-bottom-line approach, valuing the economic, environmental, and social impacts of a shortfall in transportation capacity relative to the demands likely to be imposed by the oil and gas extraction industry. Although the study has considered a number of potential costs, quantification has focused on a select set of effects:

1. Economic losses resulting from a shortfall of transportation capacity
    a. State and local tax revenues
    b. State-wide economic activity, labor income, and job creation in the oil and gas sector and across linked industries with a special focus on private net revenue and income
    c. Transportation network user benefits in terms of travel times and costs
2. Environmental cost savings resulting from an under-provision of capacity
    a. Roadway emissions costs avoided
    b. Oil and gas production site emissions avoided
3. Social cost savings resulting from an under-provision of capacity
    a. Roadway accidents avoided

Table 65 summarizes our findings in each of these categories. Environmental and social costs are defined as negative values because they represent a negative opportunity cost; that is, the reduced activity resulting from transportation capacity shortfalls reduces potential emissions and safety impacts. However, it should also be noted that, although we value the full environmental benefit of a capacity shortfall, many of the effects are mitigatable, and specific mitigations must be assessed if specific capacity improvements are considered.

Table 65: Summary of Opportunity Costs by Category, ($ Million)

Revenues and User Benefits		Environmental and Social Costs		Macroeconomic Impact	
Profit, rents, dividends, and private royalties[a]	$3,784	Site emissions and ecological impacts	$1,246	Total regional output	$34,794
State and local tax revenue	$2,756	Vehicle emissions	$24	Total labor income	$11,791
User cost savings	$4,943	Safety impacts	$101	Long-term jobs (FTE)[b]	26,802
Total	**$11,483**	**Total**	**$1,371**		

Note: Full-time equivalent (FTE)

[a] Represents the portion of total macroeconomic output that is additional in-state private citizen/corporate profit net of expenses and resource depletion.

[b] Assumes a 10-year term of employment.

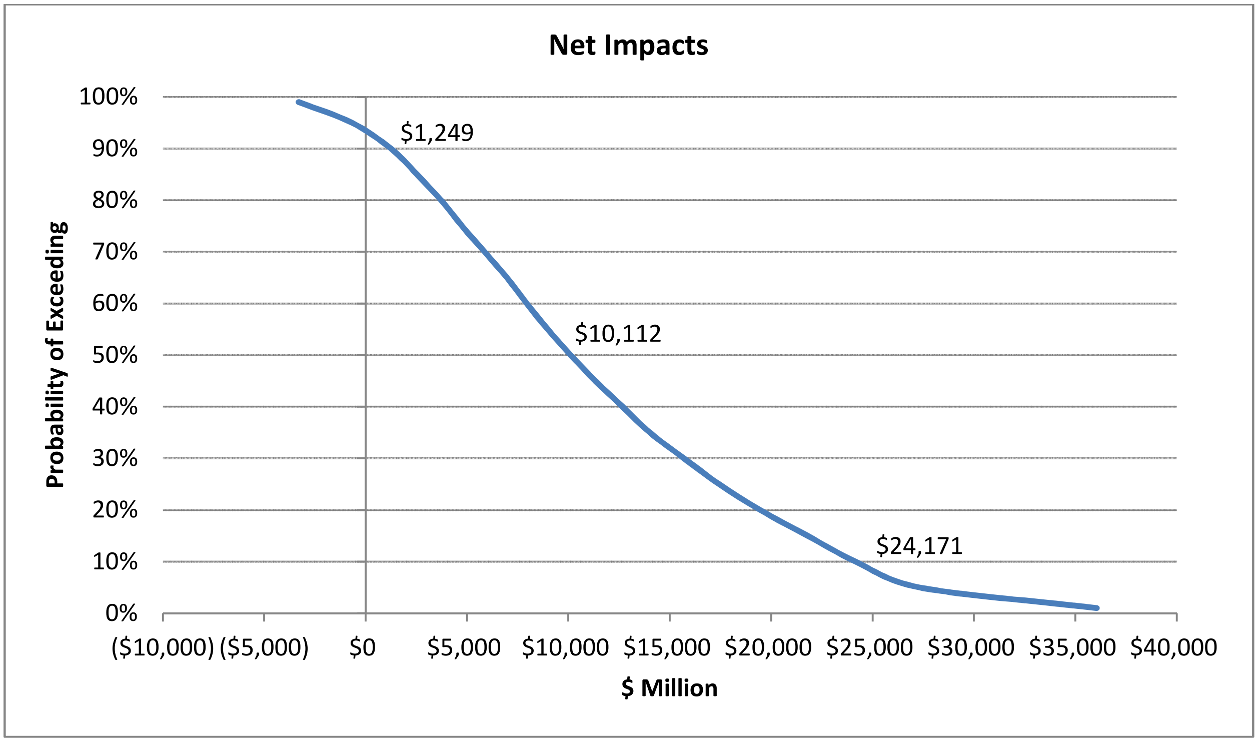
We have also specifically netted out overlapping effects in order to develop an estimate of the net opportunity cost to the State of capacity shortfalls in the Basin. These additive categories of opportunity cost are:

- Private profits, rents, dividends, and royalties not earned specifically due to capacity constraints
- State and local tax revenues not raised
- User cost savings not enjoyed
- Monetized valuation of savings in site and roadway emissions due to reduced activity
- Monetized valuation of savings from potential safety effects

The net valuation of these monetized effects has a present value, in 2012 dollar terms, of $10.1 billion over the next 30 years. In other words, the shortfall in transportation capacity across all modes considered, which is forecast to reduce potential output by $15.8 billion in present-value terms over 30 years, is worth the equivalent of about $10.1 billion in lost economic, social, and environmental opportunities. This is the value against which we believe the costs of potential improvements should be weighed.

Similar to the gap assessment, the opportunity cost was also estimated in a risk analysis framework. Figure 59 depicts the probability distribution estimated. As the figure indicates, there is a 90% probability that the opportunity cost of transportation capacity shortfalls in the Uinta Basin will be $1.3 billion or more, and there is a 10% probability the present value of opportunity costs will be greater than about $24 billion. The median forecast of opportunity costs is about $10.1 billion in present-value terms.

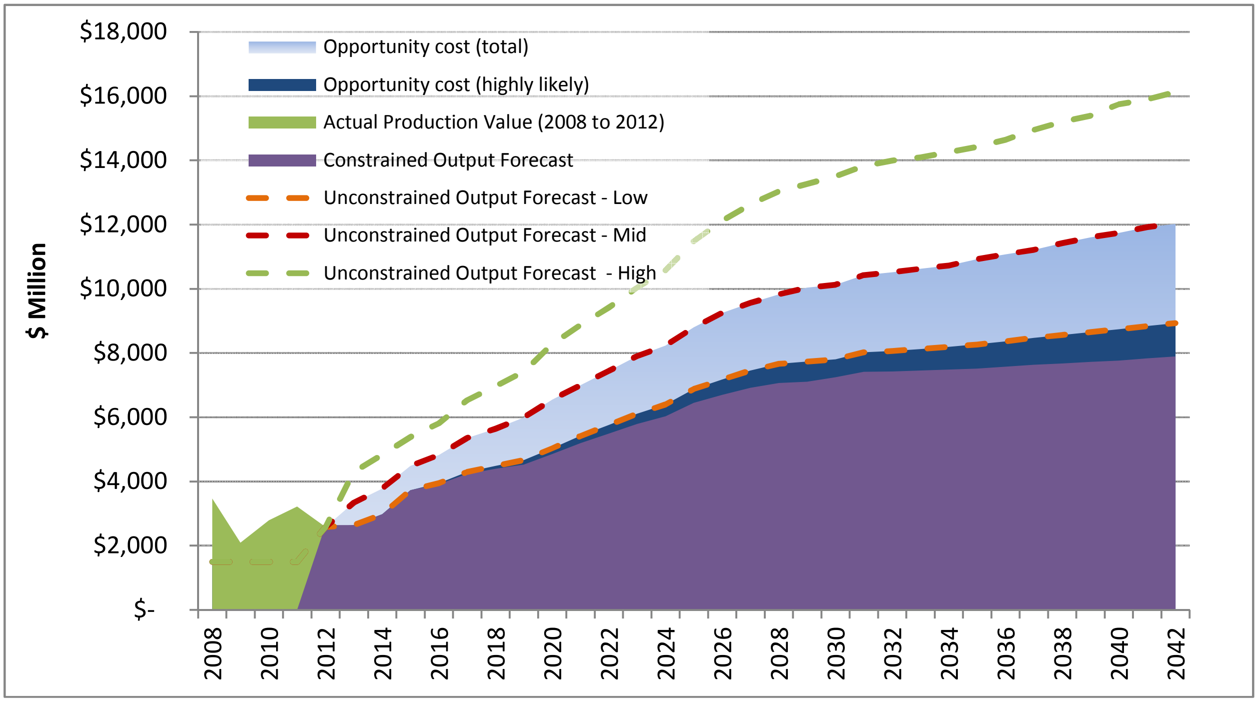
Figure 59: Net Opportunity Costs, Present Value, Risk Analysis Results, ($ Million)



9 Conclusions

The UBETS Phase 1 study estimated potential oil and gas production in the Uinta Basin given all existing constraints other than transportation. The study also estimated production in light of the existing and planned transportation network. The difference between these two forecasts is the "gap"—the future production loss due to transportation capacity shortfalls in the Uinta Basin. For reference, Figure 60 depicts the gap between the unconstrained and constrained forecasts.

Figure 60: Estimation of Gap between Unconstrained and Constrained Forecasts



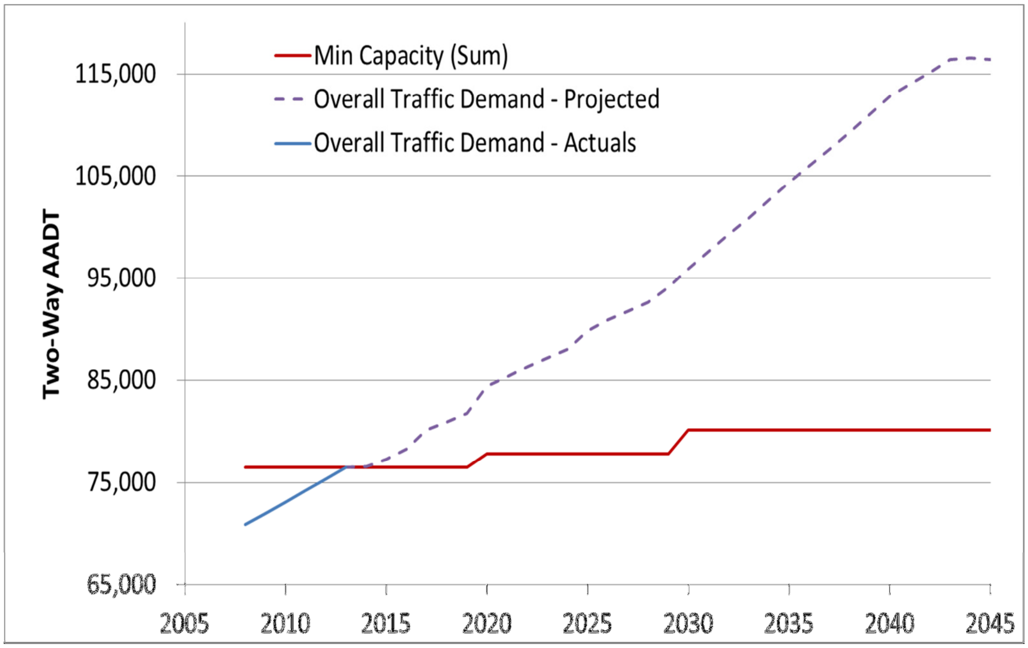
This gap between the transportation-constrained and -unconstrained forecasts is valued at about $15.8 billion, in present-value terms, over 30 years. As indicated in Table 66, the "lost" production due to transportation constraints is between $8 billion and $29 billion with 80% confidence.

Table 66: Production Gap Estimate, Results of Risk Analysis - ($ Million)

Forecast Level	Total (Undiscounted)	Present Value at 3%
Low	$14,734 million	$8,128 million
Mid	$29,037 million	$15,762 million
High	$52,839 million	$29,023 million

These findings indicate that transportation capacity represents a genuine constraint to energy production in the Uinta Basin. The forecast indicates that demand will exceed capacity on certain segments of the roadway network within the next 5 years. In fact, baseline traffic alone (excluding new oil and gas trips) is expected to exceed capacity on portions of US 40 by 2020. Capacity across all modes will start impacting energy output by 2015. By 2020, several key routes for energy production inputs and outputs will face capacity constraints that will limit production. Figure 61 below presents an aggregate depiction of total transport demand and capacity in the Uinta Basin.

Figure 61: Summary of Basin-wide Transportation Capacity and Future Demand

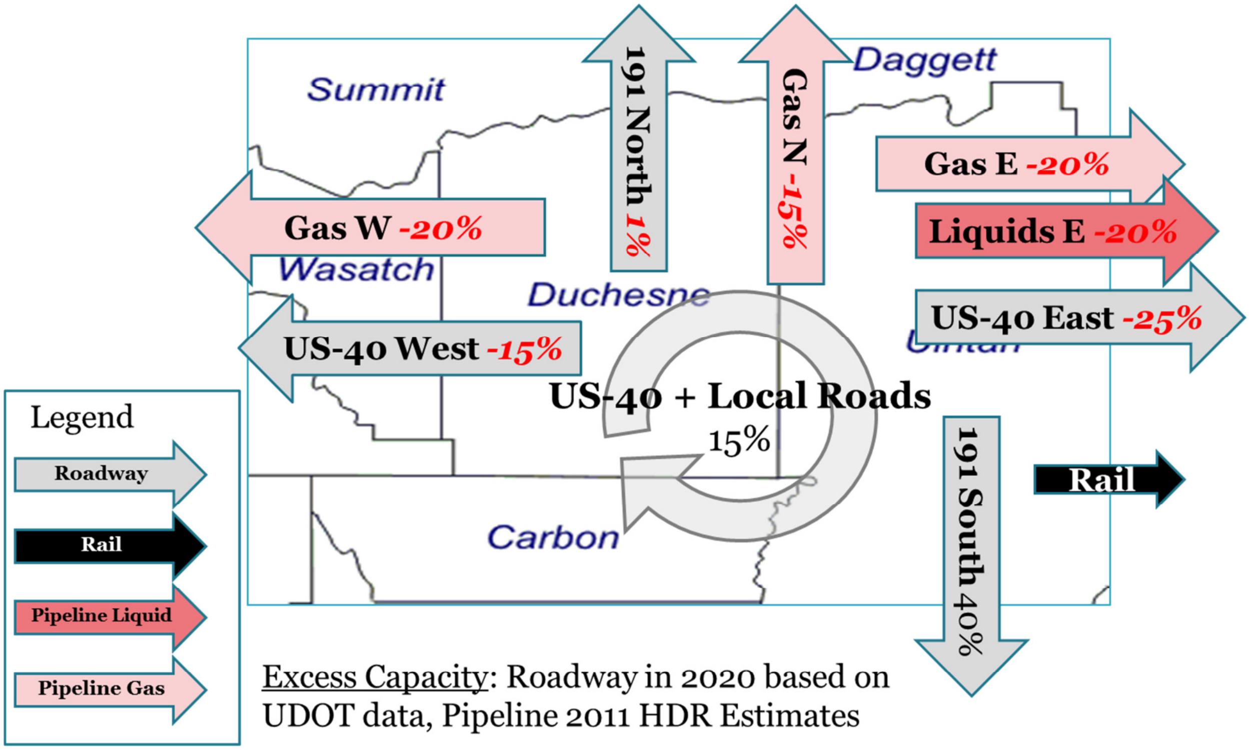


As indicated in Figure 62 below, without added investment, routes with capacity issues will be:

- Gas pipelines to the east, west, and north of the Uinta Basin
- Oil pipeline to the east
- US 40 to the west and east
- US 191 to the north

In addition, the analysis indicates that the existing rail connection is not adequate to support energy commodity movements and existing pipeline capacities will become inadequate.

Figure 62: Summary of Route Capacity Issues in 2020



Investment in transportation capacity presents a significant opportunity to the economic well-being of the region. The value of potential added production over the next 30 years is about $29 billion in future-value terms.[56] This added oil and gas output is expected to generate significant economic benefits as well as some social and environmental consequences. The opportunity cost assessment indicates that, in present-value terms, addressing capacity constraints has a value of about $10 billion in present-value terms plus the value of about 26,800 new jobs[57] over 30 years. Overall, addressing transportation constraints would result in more than $64 billion in net new economic activity[58] in the State through 2042.

Growth in production enabled by added transportation capacity can be expected to generate added tax revenues, suggesting that investment in the transportation network could, at least in part, be self-funded. In average annual terms, the added production potential equates to about $1 billion in additional oil and gas output, which would generate about $180 million in new state and local tax revenues. Further tax revenue from employee incomes, corporate taxes, and production input sales taxes, were not calculated for this study but could be expected to generate further tax revenues. Table 67 summarizes the lifecycle revenue estimates by tax type.

---

[56] $15.8 billion in present-value terms.
[57] Assuming 10- year job terms.
[58] $34.8 billion in present-value terms, state-wide direct, indirect, and induced economic output.

Table 67: Potential Tax Revenue Estimates

Tax	Current Rate	Total Potential Revenue, 2013–2045 ($ Million)	Present-Value at 3% ($ Million)
Oil and gas severance	3%–5%	$1,394	$714
Oil and gas conservation	0.20%	$61	$31
Federal royalty remittance	6.00%	$1,177	$604
State royalty (SITLA)	12.50%	$689	$357
State sales tax	4.70%	$1,625	$834
County and local option sales tax	0.25%	$421	$216
Total		**$5,367**	**$2,756**

Note: School & Institutional Trust Lands Administration (SITLA).

In addition to tax revenue generation, there are significant other economic benefits that will not be realized specifically due to transportation capacity shortfalls in the Uinta Basin. These benefits include creation of jobs in the oil and gas and related industries and in industries serving those workers; generation of private revenues to owners of affected property; and benefits to all users of the transportation network whose travel times and costs are affected by capacity shortfalls. A counterpoint to this, however, is that expansion of transportation capacity to facilitate oil and gas expansion could have certain negative environmental and social impacts if not properly mitigated. The net monetized value of all of these opportunity costs is $10.1 billion in present-value terms over 30 years.

In conclusion, the UBETS Phase 1 study produced four key findings:

1. Transportation represents a genuine challenge to the growth of energy production;
2. The opportunity cost in terms of revenues and public benefits is significant;
3. There are some environmental and social impacts that need to be addressed; and
4. Although this study assessed the transportation constraints, consideration should also be given to policy and industry regulation that could affect production, to land use, and to environmental impacts.

Appendix A: Summary of Transportation Demand and Capacity Data Collection and Estimation

The purpose of the Uinta Basin Energy and Transportation Study (UBETS) was to evaluate the extent that transportation could be a limiting factor to the future of energy development in the Uinta Basin. Potential transportation expansion options include increased highway capacity, increased pipeline capacity, and/or the extension of rail service to the Uinta Basin.

To facilitate the UBETS, as a high-level estimate of the effect of energy development on transportation demand, several simplifying assumptions were used in the development of the traffic forecasts and capacity estimates. These assumptions and inputs for the traffic and capacity analysis are documented in this technical memorandum. Additional information regarding existing crash data is also provided.

Major Energy Corridors

As part of the traffic analysis, major transportation corridors that serve as primary routes for energy-related development in Duchesne and Uintah counties were identified. These energy corridors are the highways and roads used to access the major energy development areas in the Uinta Basin. The corridors were defined to present a manageable but sufficient level of detail to understand existing and future travel demand.

The corridors were identified through review of existing facilities and movement volumes. State highways in to and out of the Uinta Basin were included as well as 5880 West and Nine Mile Road, which are also significant facilities for energy development. Other state highways such as S.R. 149, S.R. 301, and S.R. 310, were not included because of the limited energy development along these routes. S.R. 35 west of Tabiona was also not included due to winter closures and steep grades that make it unsuitable for heavy truck traffic. The energy corridors were subsequently modified during November 2012, based on input from the consultant team to better reflect energy-related traffic patterns. These changes were included

- Added S.R. 121 from 2000 West in Neola to Main Street in Vernal
- Added S.R. 35 from S.R. 208 to S.R. 87
- Added S.R. 208 from U.S. 40 to S.R. 35
- Adjusted the segmentation on U.S. 40

Existing Travel Demand

The existing traffic conditions on the major energy corridors are based on traffic data from *Traffic on Utah Highways 2011* published by the Utah Department of Transportation (UDOT). The traffic information provided is the Annual Average Daily Traffic (AADT) on state highways and federal-aid routes. On state highways, the corresponding percentage of truck traffic for each highway segment is also provided. The routes are segmented at major intersections and highway segments where traffic volumes show a substantial increase or decrease. As a result, there are 59 highway segments on the major energy corridors. The AADT for these segments was summarized for each of the major energy corridors using a weighted average and is presented in Table 68.

Table 68: Existing (2011) Travel Demand on Major Energy Corridors

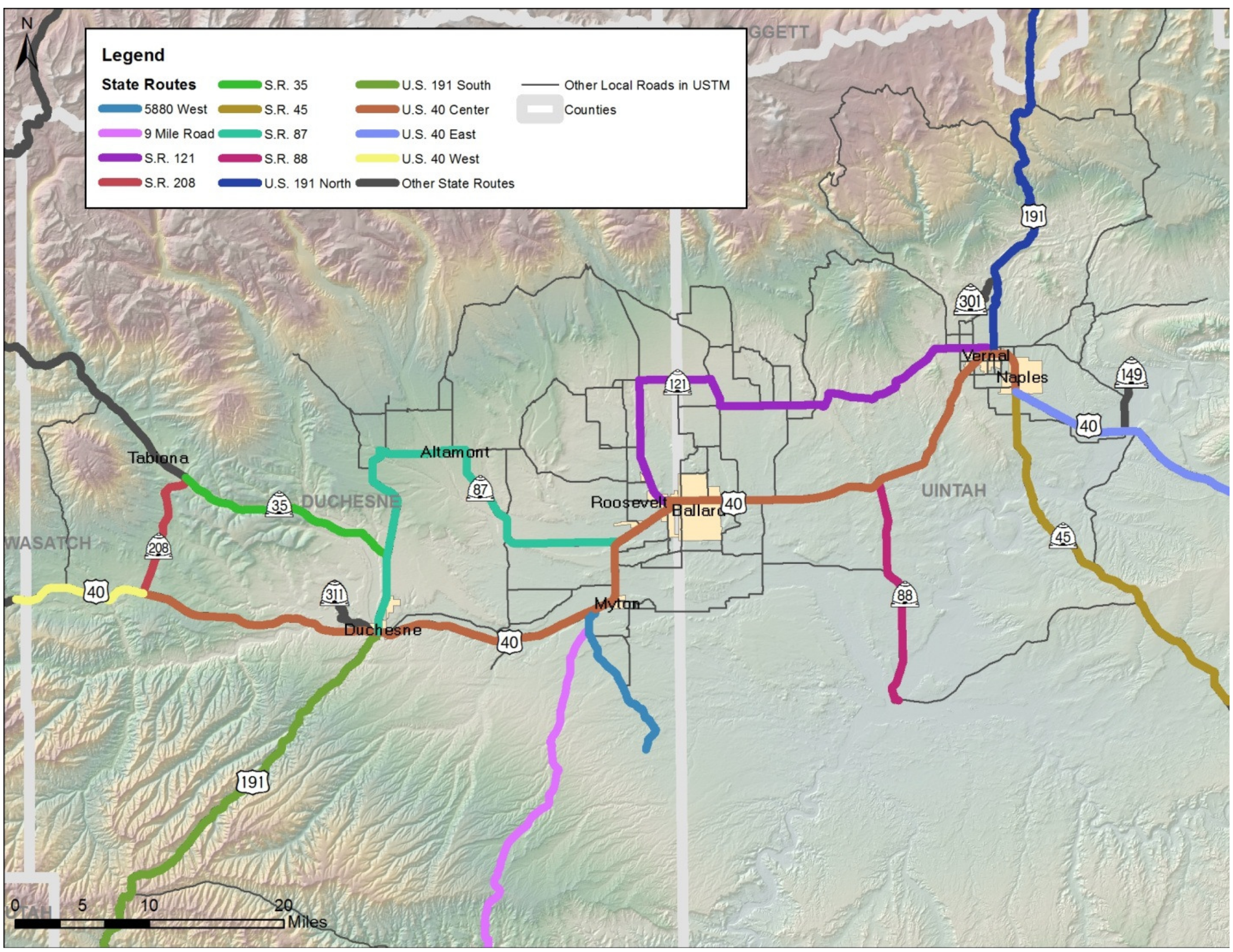
Highway Segment	Total AADT	Single-Unit Truck AADT	Combo Truck AADT	Truck AADT	Daily Vehicle-Miles Traveled
U.S. 40 west (Wasatch County to S.R. 208)	4,500	510	1,100	1,610	42,730

Highway Segment	Total AADT	Single-Unit Truck AADT	Combo Truck AADT	Truck AADT	Daily Vehicle-Miles Traveled
U.S. 40 central (S.R. 208 to Naples)	8,100	1,600	1,280	2,880	657,660
U.S. 40 east (Naples to Colorado)	3,620	1,000	530	1,530	91,190
U.S. 191 south (Carbon County to U.S. 40)	540	130	70	200	18,810
U.S. 191 north U.S. 40 to Daggett Co.)	1,870	280	200	480	48,120
S.R. 35 (S.R. 208 to S.R. 87)	170	30	10	40	6,800
S.R. 45	4,000	1,480	600	2,080	68,020
S.R. 87	1,380	310	190	500	52,390
S.R. 88	2,330	1,120	560	1,680	39,580
S.R. 121	2,220	550	210	760	89,310
S.R. 208	350	90	80	170	3,520
Nine Mile Road/5800 West	100	10	0	10	3,760

Source, UPlan

Note: Annual average daily traffic (AADT).

Figure 63: Major Energy Corridors and USTM Network



Source: UPlan

Future Travel Demand

Future traffic volume estimates were obtained using the Utah Statewide Travel Demand Model (USTM). The travel demand modeling was performed using USTM version 1.0. At the time of the study, a minor update to USTM was being completed that improved the freight component used to estimate truck traffic based on freight travel through Utah. However, due to the relatively short project schedule and limitations of the model update, the existing model version 1.0 was used for the analysis.

Highway Network

The existing transportation network for the study area includes state highways and regionally significant roads. Table 69 provides the approximate number of roads contained in USTM in Duchesne and Uintah counties. The USTM network includes state highways and other regionally significant roadways and is shown above in Figure 63 above.

Table 69: USTM Network Summary by County

County	Number of Local Roads in Model	Number of State Highways in Model	Total Number of Roads in Model
Duchesne	52	8	60
Uintah	56	8	64
Total	**108**	**16**	**124**

Source: USTM

USTM provides year 2020, 2030, and 2040, forecasts for a build scenario, which assumes that all projects in UDOT's 2011–2040 Long-Range Transportation Plan are completed as planned. Table 70 lists the improvements in the UDOT 2011–2040 Long-Range Transportation Plan for Duchesne and Uintah counties. These improvements are contained in the USTM and are separated by phase.

Table 70: Planned Capacity Projects

County	Project Name and Location	Length	Improvement Type	Estimated Cost
Phase One 2011-2020				
Duchesne	U.S. 40 Mile post (MP) 70.1 to MP 100.0 Duchesne Urban Area STIP CD	29.9	Passing Lanes	$18,000,000
Uintah	S.R. 121 MP 37.3to MP 40.3 (existing 3-lane)	3.0	Widening	$5,000,000
Uintah	U.S. 40 widen eastbound and westbound from 1 lane to 2 lanes from MP 130.3 to MP 133.4	3.1	Passing Lanes	$5,000,000
Uintah	U.S. 40 MP 152.0 to 153.0 eastern limit of Naples	1.0	Passing Lanes	$4,000,000
Uintah	U.S. 40 widen eastbound and westbound from MP 117.8 to MP 119.4 Roosevelt and Ballard Urban Area	1.6	Passing Lanes	$10,000,000
Phase One Total				$42,000,000
Phase Two 2021-2030				
Duchesne	U.S. 40 MP 107.6 eastern limit of Duchesne to western limit of Roosevelt	1.2	Passing Lanes	$2,000,000

County	Project Name and Location	Length	Improvement Type	Estimated Cost
Duchesne	U.S. 191 widen northbound and southbound from 1 lane to 2 lanes from MP 262.2 to MP 271.8	9.6	Passing Lanes	$14,000,000
Wasatch/ Duchesne	U.S. 40 widen eastbound and westbound from MP 37.5 to MP 69.2 Daniels Summit to western limit of Duchesne	31.7	Passing Lanes	$22,000,000
Phase Two Total				$38,000,000
Phase Three 2031-2040				
Uintah/ Daggett	U.S. 191 widen northbound and southbound from 1 lane to 2 lanes from MP 363.6 to MP 392.6	29.0	Passing Lanes	$44,000,000
Phase Three Total				$44,000,000

Source: UDOT, Long-Range Transportation Plan

Energy-Related Traffic Growth in USTM Forecasts

The model version used for the UBETS Phase 1 includes a simple truck traffic model, which was used for the analysis. Model truck traffic is based on linear regression equations that include the number of households and employment in the area. The equations used to generate truck traffic are summarized below in Table 71. Oil and gas-related trips are not specifically generated in version 1 of the model.

Table 71: USTM Version 1 Truck Traffic Trip Generation

Equations
Single Unit Trucks = (Households × 0.099) + (Retail Employment × 0.253) + (Other Employment × 0.068) + (Industrial Employment × 0.242) + ((Agricultural Employment + Mining Employment + Construction Employment) × 0.289)
Multi-Unit Trucks = (Households × 0.038) + (Retail Employment × 0.065) + (Other Employment × 0.009) + (Industrial Employment × 0.104) + ((Agricultural Employment + Mining Employment+ Construction Employment) × 0.174)

Source: USTM

The goal for the traffic forecasts was to develop forecasts of car and truck use absent the increase in energy development. For study purposes, energy-development assumptions were being developed separately and would be added to baseline growth that included continuing statewide commerce and modest population and employment growth in the Uinta Basin. The socioeconomic assumptions in USTM were evaluated to see what assumptions regarding employment and population growth from energy-related development are contained in the model, with the goal of stripping out this level of growth so that it could be added manually pending other work by HDR.

As shown in Table 72, USTM assumes flat employment and population growth in Duchesne and Uintah counties and does not reflect an increase in energy-related development. Because USTM does not include energy-related development, the traffic and truck forecasts represent background traffic growth in the region and do not include oil and gas-related truck traffic from future energy development.

Table 72: Duchesne and Uintah County USTM Population and Employment Growth

	Total				Annual Growth Rate		
Forecast Category	2008	2020	2030	2040	2008–2020	2020–2030	2030–2040
Industrial employment	2,700	2,701	2,646	2,650	0%	0%	0%
Mining employment	5,237	4,778	5,041	5,054	–1%	1%	0%
Construction employment	2,045	2,307	2,381	2,381	1%	0%	0%
Total employment	31,455	33,623	35,046	35,218	1%	0%	0%
Population	46,195	58,083	61,935	65,098	2%	1%	0%
Households	15,569	19,645	22,175	24,391	2%	1%	1%

Source: USTM

Traffic Forecasts

Table 73 through Table 75 provide years 2020, 2030, and 2040, traffic forecasts on the major energy corridors. The traffic forecasts were developed through a comparison of travel demand model output to existing traffic volume data, as published by UDOT in *Truck Traffic on Utah Highways*. The model growth was added to the reported traffic volumes to generate AADT and truck AADT forecasts. These traffic forecasts were automated from the USTM results in order to match base-year (2011) traffic counts and represent baseline growth absent energy development. Vehicle-miles traveled simply represent the traffic volume multiplied by the distance on each highway segment.

U.S. 40 has the highest forecasted traffic volumes of the energy corridors, with at least twice the AADT compared to the other energy corridors. The AADT on the segment of U.S. 40 between S.R. 208 and Naples is even higher than on the other segments of U.S. 40, with more than 10,000 vehicles a day by 2040.

Table 73: Year 2020 Travel Demand on Major Energy Corridors

Highway Segment	Total AADT	Single-Unit Truck AADT	Combo Truck AADT	Truck AADT	Daily Vehicle-Miles Traveled
U.S. 40 west (Wasatch County to S.R. 208)	4,390	540	1,140	1,680	45,160
U.S. 40 central (S.R. 208 to Naples)	9,050	1,730	1,540	3,270	724,140
U.S. 40 east (Naples to Colorado)	4,290	960	610	1,570	113,130
U.S. 191 south (Carbon County to U.S. 40)	1,850	170	130	300	64,180
U.S. 191 north (U.S. 40 to Daggett County)	2,370	280	360	640	60,940
S.R. 35 (S.R. 208 to S.R. 87)	1,790	150	160	310	30,430
S.R. 45	1,720	630	260	890	68,800
S.R. 87	1,650	330	210	540	63,120
S.R. 88	2,340	1,120	560	1,680	39,750
S.R. 121	2,620	560	210	770	105,680
S.R. 208	340	90	80	170	3,470
Nine Mile Road/5800 West	100	10	0	10	3,760

Source: USTM
Note: Annual average daily traffic (AADT). Travel demand represents baseline demand absent energy development.

Table 74: Year 2030 Travel Demand on Major Energy Corridors

Highway Segment	Total AADT	Single-Unit Truck AADT	Combo Truck AADT	Truck AADT	Daily Vehicle-Miles Traveled
U.S. 40 west (Wasatch County to S.R. 208)	4,650	610	1,390	2,000	47,820
U.S. 40 central (S.R. 208 to Naples)	9,850	1,820	1,910	3,730	787,960
U.S. 40 east (Naples to Colorado)	5,400	960	770	1,730	142,360
U.S. 191 south (Carbon County to U.S. 40)	1,790	220	240	460	62,090
U.S. 191 north (U.S. 40 to Daggett County)	3,080	290	620	910	79,050
S.R. 35 (S.R. 208 to S.R. 87)	1,690	160	230	390	28,730
S.R. 45	1,730	630	260	890	69,240
S.R. 87	1,670	340	220	560	63,700
S.R. 88	2,350	1,120	560	1,680	40,020
S.R. 121	2,980	580	220	800	120,240
S.R. 208	350	100	80	180	3,570
Nine Mile Road/5800 West	100	10	0	10	3,760

Source: USTM
Note: Annual average daily traffic (AADT). Travel demand represents baseline demand absent energy development.

Table 75: Year 2040 Travel Demand on Major Energy Corridors

Highway Segment	Total AADT	Single-Unit Truck AADT	Combo Truck AADT	Truck AADT	Daily Vehicle-Miles Traveled
U.S. 40 west (Wasatch County to S.R. 208)	5,440	750	1,820	2,570	55,990
U.S. 40 central (S.R. 208 to Naples)	11,100	1,940	2,440	4,380	888,120
U.S. 40 east (Naples to Colorado)	6,920	960	980	1,940	182,410
U.S. 191 south (Carbon County to U.S. 40)	2,940	270	360	630	101,920
U.S. 191 north (U.S. 40 to Daggett County)	4,050	290	950	1,240	104,050
S.R. 35 (S.R. 208 to S.R. 87)	2,890	220	370	590	49,130
S.R. 45	1,750	630	260	890	69,920
S.R. 87	1,900	350	240	590	72,740
S.R. 88	2,370	1,120	560	1,680	40,260
S.R. 121	3,260	580	220	800	131,420
S.R. 208	350	90	80	170	3,570
Nine Mile Road/5800 West	110	10	0	10	4,140

Source: USTM
Note: Annual average daily traffic (AADT). Travel demand represents baseline demand absent energy development.

Existing Daily Capacities

Traffic operations are typically defined by level of service (LOS) definitions in the *Highway Capacity Manual* (HCM) 2010. The HCM is a nationally recognized resource for traffic engineers produced by the Transportation Research Board (TRB). The HCM provides quantitative measures to assess how well a road, bicycle, pedestrian, or transit facility operates based on levels that range from A through F, similar to grades in school. For roads, LOS A represents free-flow traffic conditions and little delay, and LOS F represents severe congestion and delay. LOS B through LOS E represent progressively worse traffic conditions.

Different LOS measurements apply to different road types. For example, on rural two-lane highways, there are three measures of LOS: average travel speed (ATS), percent time spent following (PCTF), and percent of free-flow speed (PFFS). Multi-lane highways are measured by the density of vehicle traffic, which relates to the freedom and ability of drivers to maneuver within the traffic stream. For roads with frequent traffic signals, as is common in more urban environments, the LOS is based on signal delay and effects of multiple traffic signals. UDOT strives to maintain rural roads at LOS C or better during the peak travel hours. HCM defines LOS C as "most vehicles are traveling in platoons. Speeds are noticeably curtailed on all three classes of [two-lane rural] highway."

In addition to having three measurements of LOS, two-lane highways are also separated into three classes to determine LOS. The HCM defines the three classes as follows:

- **Class I two-lane highways** are highways where motorists expect to travel at relatively high speeds. Two-lane highways that are major intercity routes, primary connectors of major traffic generators, daily commuter routes, or major links in state or national highway networks are generally assigned to Class l. These facilities serve mostly long-distance trips or provide the connections between facilities that serve long-distance trips.
- **Class II two-lane highways** are highways where motorists do not necessarily expect to travel at high speeds. Two-lane highways functioning as access routes to Class I facilities, serving as scenic or recreational routes (and not as primary arterials), or passing through rugged terrain (where high-speed operation would be impossible) are assigned to Class ll. Class II facilities most often serve relatively short trips, the beginning or ending portions of longer trips, or trips for which sightseeing plays a significant role.
- **Class III two-lane highways** are highways serving moderately developed areas. They may be portions of a Class I or Class II highway that pass through small towns or developed recreational areas. On such segments, local traffic often mixes with through traffic, and the density of unsignalized roadside access points is noticeably higher than in a purely rural area. Class III highways can also be longer segments passing through more spread-out recreational areas, also with increased roadside densities. Such segments are often accompanied by reduced speed limits that reflect the higher activity level.

Table 76 provides the LOS thresholds for two-lane highways, and Table 77 lists the LOS density thresholds for multi-lane highways. It should be noted that the density thresholds for multi-lane highways are similar to those used for freeways, so going from a two-lane highway to a four-lane highway can result in a significant increase in capacity.

Table 76: Two-Lane Highway Level of Service

LOS	Class I Highways		Class II Highways PTCF (%)	Class III Highways PFFS (%)
	ATS (mph)	PCTF (%)		
A	> 55	≤ 35	≤ 40	> 91.7
B	> 50 – 55	> 35 – 50	> 40 – 55	> 83.3 – 91.7
C	> 45 – 55	> 50 – 65	> 55 – 70	> 75.0 – 83.3
D	> 40 – 45	> 65 – 80	> 70 – 85	> 66.7 – 75.0
E	≤ 40	> 80	> 85	≤ 66.7

Note: Level of service (LOS); average travel speed (ATS); percent time spent following (PCTF); and percent of free-flow speed (PFFS).

Table 77: Density Thresholds for Multi-lane Highway Level of Service

LOS	Free-flow Speed (mph)	Density (PC/MI/LN)
A	All	≤ 11
B	All	> 11 – 18
C	All	> 18 – 26
D	All	> 26 – 35
E	60 55 50 45	> 35 – 40 > 35 – 41 > 35 – 43 > 35 – 45
F	60 55 50 45	> 40 > 41 > 43 > 45

Note: Level of service (LOS); miles per hour (mph); passenger cars per mile per lane (PC/MI/LN).

The capacity analysis was performed for uninterrupted flow (no traffic signals) using the HCM methodologies for two-lane and multi-lane highways. The HIGHPLAN software analysis tool (part of the Highway Capacity Software suite) was used to implement the HCM procedures.

The capacity estimates require a greater amount of detailed highway information than is available at the corridor level. As a result, the highway segments in *Traffic on Utah Highways* were used to identify highway sections with common characteristics, such as the typical number of travel lanes and traffic volumes that could be aggregated to create larger highway sections. The resulting highway sections are smaller than the identified energy corridors but detailed enough to develop a planning-level daily capacity.

Table 78 summarizes highway segments and the inputs used for the capacity analysis. In order to estimate daily capacities in HIGHPLAN, the following inputs are required:

- Number of travel lanes
- Posted speed limit
- Area type
- Terrain
- Planning analysis factor (K)

- Directional distribution factor (D)
- Peak-hour factor
- Heavy vehicle proportion
- Number of passing lanes and spacing
- Percent no passing

Number of Travel Lanes

The number of existing travel lanes is generally one lane in each direction on most roads in the study area. However, some highways have passing lanes, and there are several road segments with four travel lanes in more-developed areas. These segments were identified using spatial data published by UDOT for the number of through lanes based on the Highway Performance and Monitoring System[59] data.

Posted Speed Limit

The posted speed limit was based on data provided by UDOT that identify the location of speed limit signs.

Area Type

The area type is the general categorization of the land use based on the level of urbanization. Highway segments in the cities of Duchesne, Roosevelt, and Vernal were assumed to be rural developed, while all other segments were assumed to be rural and undeveloped.

Terrain

The terrain that the highway passes through affects roadway performance because heavy vehicle speeds decrease in response to upgrades or downgrades. In the HCM, there are three categories of terrain used to account for the effect of heavy vehicles: level, rolling, and mountainous. For the analysis, rolling terrain was generally assumed except in the more developed areas where terrain was assumed to be level.

Planning Analysis Factor (K)

The planning analysis (K) factor identifies the ratio of the traffic volume in the study hour to the AADT and typically ranges from 0.09 to 0.2. Often, in urban areas, the 30th-highest hourly volumes are used to define the design hour used to estimate the K factor. In rural areas, the design hour frequently shifts to the 50th highest or even 100th highest in areas with a high proportion of recreational traffic. In the Uinta Basin, two automated traffic recorder (ATR) stations provide the highest-hour traffic data by year. Station 425 is on U.S. 40 approximately 3 miles west of Roosevelt, and station 424 is on U.S. 191 3 miles north of U.S. 40 in Vernal. The 50th-highest hour from station 425 was assumed for U.S. 40 and all other highways except for U.S. 191 north of Vernal because there are traffic data available from ATR station 424. On U.S. 191, the 100th-highest hour was assumed due to the high proportion of recreational traffic going to Flaming Gorge Reservoir.

Directional Distribution Factor (D)

The directional distribution (D) factor is the proportion of traffic during the study period traveling in the predominant traffic demand direction. A value of 0.51 means that 51% of the traffic is going in the peak direction, while a value of 0.60 means that 60% of the traffic is going in the peak direction. The D factors

59 See http://www.fhwa.dot.gov/policyinformation/hpms.cfm

are from ATR station 425 and were assumed for U.S. 40 and all other highways except for U.S. 191 north of Vernal.

Peak-Hour Factor

Typically, the highest 15-minute traffic flow in the peak hour is not sustained throughout the hour. The peak hour factor (PHF) is a factor calculated to reflect this hourly variation. On freeways, the PHF generally ranges from 0.85 to 0.98. The higher the PHF, the more uniform traffic flows during the highest peak hour of traffic. The PHFs used in the analysis were a generic assumption for rural areas of 0.88 since sub-hourly volume data were not available.

Heavy Vehicle Proportion

The heavy vehicle proportion data are from *Truck Traffic on Utah Highways 2011* published by UDOT. The heavy vehicle proportion was summarized for each of the major energy corridors using a weighted average for the highway segment.

Number of Passing Lanes and Spacing

The number of passing lanes on each highway segment and the lengths of these existing passing lanes were estimated from the spatial data published by UDOT that includes the number of through lanes from the Highway Performance and Monitoring System data. Due to the project schedule, simplifying assumptions were made for the number of passing lanes and spacing on each segment. It was assumed that there was an equal number of passing lanes in both directions of travel and that each passing lane was 1 mile long.

Percent No Passing

Percent no passing is the percentage of the highway where passing is not allowed, typically indicated by double solid yellow center striping. Since corridor-level data were not available, a conservative estimate of 50% was assumed.

The highway class is not required for HIGHPLAN analysis but is derived from the posted speed limit input.

Table 79 summarizes the existing daily LOS C capacities for the major energy corridors. The daily capacities represent passenger car equivalents (PCEs). A PCE is the number of passenger cars that will result in the same traffic operations as a single heavy vehicle. On two-lane highways, the PCE for heavy vehicles ranges from 1 to 2.7 depending on terrain and traffic volume but is generally greater than 1. Since the PCE daily capacities reflect the daily capacity if all traffic consisted only of passenger cars, the capacities presented below are greater than the actual service capacities since there are heavy vehicles in the traffic stream.

Since the number of travel lanes and resulting capacity vary within several of the identified energy corridors, the minimum, maximum, and average daily capacities are provided. The local road capacities represent the USTM capacities and were not estimated using the HCM procedures due to the number of local roads in the Uinta Basin.

Table 78: Summary of Capacity Analysis Inputs

Segment	Begin	End	Travel Lanes	Posted Speed (mph)	Area Type	Terrain	K factor	D factor	PHF	Average Truck %	Passing Lanes	Spacing (miles)
U.S. 40 west	58.0	68.2	2	65	Rural undeveloped	Rolling	0.1	0.55	0.88	36%	4	4.5
U.S. 40 central	68.2	85.9	2	65	Rural undeveloped	Rolling	0.1	0.55	0.88	37%	8	2.9
U.S. 40 central	85.9	86.9	4	35	Rural developed	Level	0.1	0.55	0.88	33%	NA	NA
U.S. 40 central	86.9	111.4	2	65	Rural undeveloped	Rolling	0.1	0.55	0.88	24%	4	4.2
U.S. 40 central	111.4	115.2	4	35	Rural developed	Level	0.1	0.55	0.88	28%	NA	NA
U.S. 40 central	115.2	141.1	2	65	Rural undeveloped	Rolling	0.1	0.55	0.88	44%	4	4.7
U.S. 40 central	141.1	148.2	4	35	Rural developed	Level	0.1	0.55	0.88	90%	NA	NA
U.S. 40 east	148.2	174.6	2	65	Rural undeveloped	Level	0.1	0.55	0.88	42%	1	26.1
U.S. 191 south	260.2	294.8	2	55	Rural undeveloped	Rolling	0.1	0.55	0.88	36%	0	NA
U.S. 191 north	352.6	353.1	4	35	Rural developed	Level	0.1	0.55	0.88	19%	NA	NA
U.S. 191 north	353.1	378.3	2	50	Rural undeveloped	Rolling	0.16	0.62	0.88	26%	12	1.9
S.R. 35	45.0	62.0	2	55	Rural undeveloped	Level	0.1	0.55	0.88	25%	0	NA
S.R. 45	0.0	40.0	2	65	Rural undeveloped	Rolling	0.1	0.55	0.88	52%	2	38.7
S.R. 87	0.0	38.2	2	55	Rural undeveloped	Rolling	0.1	0.55	0.88	36%	0	NA
S.R. 88	0.0	17.0	2	60	Rural undeveloped	Rolling	0.1	0.55	0.88	72%	0	NA
S.R. 121	0.0	40.3	2	60	Rural undeveloped	Rolling	0.1	0.55	0.88	35%	0	NA
S.R. 208	0.0	10.2	2	0	Rural undeveloped	Rolling	0.1	0.55	0.88	24%	0	NA
Nine Mile Road/ 5800 West	32.7	70.3	2	45	Rural undeveloped	Rolling	0.1	0.55	0.88	25%	0	NA
Local	NA	NA	2	45	Rural undeveloped	Rolling	0.1	0.55	0.88	25%	0	NA

Segment	Begin	End	Travel Lanes	Posted Speed (mph)	Area Type	Terrain	K factor	D factor	PHF	Average Truck %	Passing Lanes	Spacing (miles)
Vernal bypass	NA	NA	2	60	Rural undeveloped	Rolling	0.1	0.55	0.88	30%	0	NA
Seep Ridge extension	NA	NA	2	60	Rural undeveloped	Rolling	0.1	0.55	0.88	72%	0	NA
U.S. 40 (Heber to Wasatch County)	17.9	58.0	2	60	Rural undeveloped	Rolling	0.1	0.55	0.88	27%	10	5.6
Heber bypass	NA	NA	2	60	Rural undeveloped	Rolling	0.1	0.55	0.88	25%	0	NA
I-80 (I-215 to U.S. 40)	58.0	68.2	2	65	Rural undeveloped	Rolling	0.1	0.55	0.88	27%	0	NA

Source: USTM

Note: Miles per hour (mph); planning analysis factor (K); directional distribution factor (D); and peak hour factor (PHF).

Table 79: Existing (2011) Daily Capacity Estimates (LOS C Passenger Car Equivalents)

Highway Segment	Minimum Capacity	Maximum Capacity	Average Capacity
U.S. 40 west (Wasatch County to S.R. 208)	9,300	9,300	9,300
U.S. 40 central (S.R. 208 to Naples)	5,700	27,400	9,775
U.S. 40 east (Naples to Colorado)	6,500	6,500	6,500
U.S. 191 south (Carbon County to U.S. 40)	6,600	6,600	6,600
U.S. 191 north (U.S. 40 to Daggett County)	5,100	27,200	5,530
S.R. 35 (S.R. 208 to S.R. 87)	6,400	6,400	6,400
S.R. 45	6,800	6,800	6,800
S.R. 87	6,600	6,600	6,600
S.R. 88	6,900	6,900	6,900
S.R. 121	6,400	6,400	6,400
S.R. 208	6,600	6,600	6,600
Nine Mile Road/5800 West	3,400	3,400	3,400
Local	200	18,500	2,220

Source: USTM
Note: Level of service (LOS).

Future Daily Capacities

The future capacities of the energy corridors were also developed based on the long-range plan projects. The long-range plan projects in the Uinta Basin are all passing lane projects, and the same simplifying assumptions used to estimate the existing passing lane spacing were assumed in developing future capacity estimates. Table 80 summarizes the assumptions regarding passing lane spacing that were used to develop the future capacity estimates.

As part of the capacity analysis, the increased capacity from generic widening scenarios was also estimated. The first scenario assumed that one passing lane would be added for 50% of centerline miles, and the second assumed full widening of the highways to four travel lanes for 100% of the centerline miles. Figure 64 and Figure 65 illustrate conceptual cross-sections for these generic widening scenarios.

Figure 64: Generic Passing Lane Cross-section

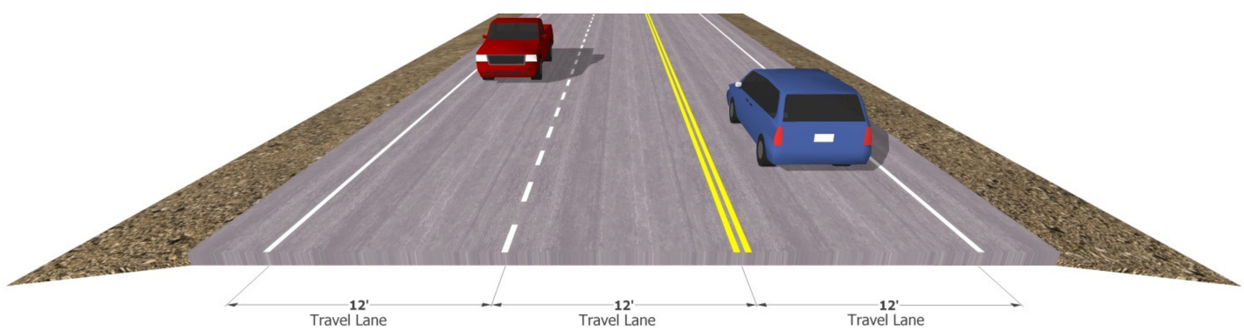
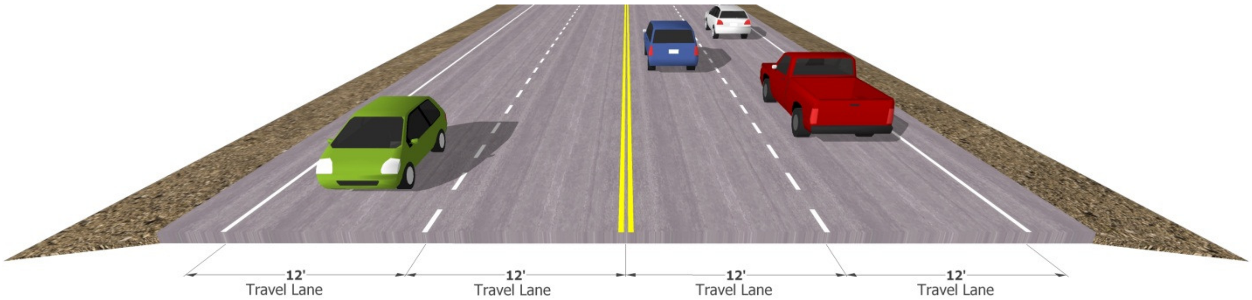


Figure 65: Generic Widening Cross-section



In addition to the highways in the Uinta Basin, several other highways were also identified for capacity improvements in these generic scenarios. These roads are either outside the study area and would be affected by energy-related development or a completely new highway. Inputs for the capacity analysis of these roads are also provided in Table 80. These highways include:

- U.S. 40 from Heber to Wasatch County
- I-80 from I-215 to U.S. 40
- A new two-lane Vernal bypass
- A new-two lane extension of Seep Ridge Road to I-70
- A new-two lane Heber bypass

Table 80: Summary of Future Passing Lanes Spacing

Segment	Begin	End	Year 2020		Year 2030		Year 2040		Add One Passing Lane for 50% of Centerline Miles	
			Passing Lanes	Spacing	Passing Lanes	Spacing	Passing Lanes	Spacing	Passing Lanes	Spacing
U.S. 40 west	58.0	68.2	4	4.5	10	1.2	10	1.2	7	1.9
U.S. 40 central	68.2	85.9	18	1.3	18	1.3	18	1.3	13	1.1
U.S. 40 central	85.9	86.9	NA	NA	NA	NA	NA	NA	NA	NA
U.S. 40 central	86.9	111.4	12	3.1	13	2.7	13	2.7	11	3.0
U.S. 40 central	111.4	115.2	NA	NA	NA	NA	NA	NA	NA	NA
U.S. 40 central	115.2	141.1	8	3.5	8	3.5	8	3.5	11	1.5
U.S. 40 central	141.1	148.2	NA	NA	NA	NA	NA	NA	NA	NA
U.S. 40 east	148.2	174.6	2	12.8	2	12.8	2	12.8	8	2.4
U.S. 191 south	260.2	294.8	0	NA	0	NA	0	NA	9	5.8
U.S. 191 north	352.6	353.1	NA	NA	NA	NA	NA	NA	NA	NA
U.S. 191 north	353.1	378.3	12	1.9	12	1.9	35	0.5	19	0.9
S.R. 35	45.0	62.0	0	NA	0	NA	0	NA	5	5.1
S.R. 45	0.0	40.0	2	38.7	2	38.7	2	38.7	12	4.8
S.R. 87	0.0	38.2	0	NA	0	NA	0	NA	10	5.7
S.R. 88	0.0	17.0	0	NA	0	NA	0	NA	5	5.1
S.R. 121	0.0	40.3	2	24.5	2	24.5	2	24.5	13	5.8
S.R. 208	0.0	10.2	0	NA	0	NA	0	NA	3	5.1
Nine Mile Road/ 5800 West	32.7	70.3	0	NA	0	NA	0	NA	10	5.6
Local	NA	NA	0	NA	0	NA	0	NA	NA	5.0

Source: USTM

Table 81 shows the year 2020, 2030, and 2040, daily capacities on the major energy corridors. The addition of passing lanes in the long-range plan results in modest increases in the daily capacities.

Table 82 lists the daily capacities for the generic widening scenarios. Widening of the major energy corridors to four lanes results in significantly more capacity than simply adding passing lanes based on HIGHPLAN analysis. As a result, the more conservative (lower) daily capacity estimate from HCM Exhibit 14-18 was assumed for a four-lane highway with a K factor of 0.11 and a directional factor of 0.55.

The difference in daily capacity between adding passing lanes and full widening is likely less than estimated with the HCM capacities due to the different methods to calculate LOS for two-lane and multi-lane highways. For two-lane highways, LOS is based on the average travel speed and percent time spent following other vehicles, while for multi-lane highways LOS is defined by roadway density in units of passenger cars per mile per lane (PC/MI/LN), which is a similar to the LOS measure for freeways.

It is important to note that the capacity erosion on arterial highways can be significant because of poor access management. The Uinta Basin is generally served by a sparse number of arterial highways, and future development in the Basin might result in the addition of multiple collector streets that are forced to access the major arterial streets. This analysis simply brackets the range of traffic capacities that could be achieved in the Basin but does not represent a detailed transportation plan that considers new collector streets and their impact on major arterial capacity.

Table 81: Future Daily Capacity with UDOT Long-Range Transportation Plan Projects (LOS C Passenger Car Equivalents)

Highway Segment	Year 2020			Year 2030			Year 2040		
	Minimum Capacity	Maximum Capacity	Average Capacity	Minimum Capacity	Maximum Capacity	Average Capacity	Minimum Capacity	Maximum Capacity	Average Capacity
U.S. 40 west (Wasatch County to S.R. 208)	9,300	9,300	9,300	11,300	11,300	11,300	11,300	11,300	11,300
U.S. 40 central (S.R. 208 to Naples)	6,500	27,400	10,700	6,500	27,400	10,700	6,500	27,400	10,800
U.S. 40 east (Naples to Colorado)	6,700	6,700	6,700	6,700	6,700	6,700	6,700	6,700	6,700
U.S. 191 south (Carbon County to U.S. 40)	6,600	6,600	6,600	6,900	6,900	6,900	6,900	6,900	6,900
U.S. 191 north (U.S. 40 to Daggett County)	5,100	27,200	5,500	5,100	27,200	5,500	5,100	27,200	5,500
S.R. 35 (S.R. 208 to S.R. 87)	6,400	6,400	6,400	6,400	6,400	6,400	6,400	6,400	6,400
S.R. 45	6,800	6,800	6,800	6,800	6,800	6,800	6,800	6,800	6,800
S.R. 87	6,600	6,600	6,600	6,600	6,600	6,600	6,600	6,600	6,600
S.R. 88	6,900	6,900	6,900	6,900	6,900	6,900	6,900	6,900	6,900
S.R. 121	6,700	6,700	6,700	6,700	6,700	6,700	6,700	6,700	6,700
S.R. 208	6,600	6,600	6,600	6,600	6,600	6,600	6,600	6,600	6,600
Nine Mile Road/5800 West	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400
Local	200	18,500	2,220	200	18,500	2,220	200	18,500	2,220

Source: USTM

Note: Level of service (LOS).

Table 82: One-Way Daily Capacity Increase from Generic Widening Improvements (LOS C Passenger Car Equivalents)

Highway Segment	Add One Lane for 50% of Centerline Miles	Add Two Lanes for 100% of Centerline Miles
U.S. 40 West (Wasatch County to S.R. 208)	1,100	15,700
U.S. 40 Central (S.R. 208 to Naples)	700	14,600
U.S. 40 East (Naples to Colorado)	1,300	17,200
U.S. 191 South (Carbon County to U.S. 40)	600	17,200
U.S. 191 North (U.S. 40 to Daggett County)	600	10,100
S.R. 35 (S.R. 208 to S.R. 87)	700	17,300
S.R. 45	800	17,100
S.R. 87	600	17,200
S.R. 88	700	17,000
S.R. 121	600	17,300
S.R. 208	600	17,200
Nine Mile Road/5800 West	400	18,900
Local*	100	17,200
Vernal Bypass (new two-lane road)	NA	4,100
Seep Ridge Extension (new two-lane road)	NA	5,100
U.S. 40 Heber to Wasatch County	1,200	16,900
Heber Bypass (new two-lane road)	NA	3,900
I-80 (I-215 to U.S. 40)	7,500	15,000

Note: Level of service (LOS).

Train and Pipeline Passenger Car Equivalents

In addition to the capacity increase from generic widening projects, the passenger car equivalents from using rail or pipeline to transport crude to the Wasatch Front were also estimated. These estimates for railroad and pipeline improvements assume one train per day with 100-car basic tanker train cars and one 8-inch-diameter crude pipeline with the minimum average flow rate of 3 feet per second. Table 83 and Table 84 summarize the assumptions used to estimate the passenger car equivalents of rail and pipeline improvements.

Table 83: Passenger Car Equivalents of Rail Improvements

Improvement Type	Quantity	Unit
Basic rail tanker capacity	543	Barrels
Number of tanker cars per day	100	Tanker cars
Total crude capacity	54,286	Barrels per day
Basic truck tanker capacity	250	Barrels
Pup tanker capacity	100	Barrels
Equivalent number of trucks	155	One-way trucks
Heavy vehicle factor	0.64	—
Passenger car equivalents of one 100-tanker car train per day	277	Passenger cars

Sources: "Tank Car Capacity and Gross Weight Limitations," *Federal Register* 49:179. 2012 and Ed. "Petroleum Semi", *Beall Corporation.* http://beallcorp.com/assets/pdfs/Petroleum-Semi-BEALL-PETROLEUM.pdf.

Table 84: Passenger Car Equivalents of Pipeline Improvements

	Quantity	Unit
Pipeline capacity (8–inch-diameter)	2.7	Gallons per foot
Pipeline velocity	3	Feet persecond
Total crude capacity (gallons)	697,248	Gallons per day
Total crude capacity (barrels)	16,601	Barrels per day
Basic truck tanker capacity	250	Barrels
Pup tanker capacity	100	Barrels
Equivalent number of trucks	47	One-way trucks
Heavy vehicle factor	0.64	—
Passenger car equivalents of one 8-inch-diameter pipeline	85	Passenger cars

Sources: McAllister, E. W. "Pipeline Rules of Thumb Handbook: A Manual of Quick, Accurate Solutions to Everyday Pipeline Engineering Problems" and Oxford: Elsevier, 2009. "Petroleum Semi", *Beall Corporation.* http://beallcorp.com/assets/pdfs/Petroleum-Semi-BEALL-PETROLEUM.pdf.

Safety Analysis

In the preceding discussion of capacities of two-lane rural highways, percentage of time following represents an important variable on high-speed routes. This capacity variable offers an intuitive connection to safety effects, since drivers who feel that their speed is constrained by slower-moving vehicles for long periods might choose to take passing risks. Evaluating safety data offers the dual benefit of quantifying the past crash experience on major roads serving the Basin while also offering a baseline understanding of crash impacts that could result from increased highway demand approaching highway capacity. The following safety data were provided by UDOT's Traffic and Safety Division to help summarize the safety on the energy corridors:

- Total crashes
- Total severe crashes
- Crash rates
- Severe crash rates

The crash rate is a calculation that normalizes the number of crashes on a road segment against the segment length and traffic volume. Crash rates are typically expressed in units of crashes per year per million vehicle-miles. The severe crash rate also normalizes crashes against length and volume but considers only "severe crashes" (incapacitating injury and fatal crashes). Severe crash rates are expressed in units of severe crashes per hundred million vehicle-miles. Both crash rates and severe crash rates were obtained for the 3 most recent years of available data (2008–2010). The rates were compared against the statewide average rates that were developed for a 5-year period for similar road segments according to volume and functional type. Only data for state highways were available, so crash statistics do not include 5880 West, Nine Mile Road, and other local roads.

Table 85 summarizes the existing crash data for the major energy corridors. Only four of the energy corridors have crashes rates that are lower than the statewide average crash rate for roads of similar functional class and volume. These segments are U.S. 40 from Naples to Colorado, S.R. 35, S.R. 87, and S.R. 88. All of the other energy corridors have crash rates above the statewide average, and the crash rates on U.S. 191 and S.R. 45 are more than double the statewide average. However, only three energy corridors have severe crash rates that are higher than the statewide average. These energy corridors are U.S. 191 South (Carbon County to U.S. 40), U.S. 191 North (U.S. 40 to Daggett County), and S.R. 208.

The severe crash rates on these segments of U.S. 191 and S.R. 208 are close to or more than double the statewide average severe crash rate.

An increase in truck traffic from energy development is a potential safety concern, since an increase in the proportion of truck traffic will result in a worse LOS due to higher traffic volumes, and an increase in the proportion of truck traffic actually decreases the daily capacity. Additionally, heavy vehicles cannot keep pace with passenger cars on upgrades or downgrades, so, in many situations, heavy vehicles create gaps in the traffic stream that are not easily filled by passing due to the limited passing opportunities on two-lane highways. As a result, queues can form behind slow-moving heavy vehicles, thereby increasing passing demand. As passing demand increases, the passing capacity decreases because, on two-lane highways, motorists have to use the opposite-direction travel lane to pass. The perception of worse LOS, increased queues behind heavy vehicles, and reduced opportunities to safely pass slow-moving vehicles can result in drivers opting to pass in less-safe circumstances, thereby creating the potential for more crashes from energy-related truck traffic.

Table 85: Crash Summary, 2006 to 2010

Highway Segment	Crash Rate[a]	Expected Crash Rate[b]	Severe Crash Rate[c]	Expected Severe Crash Rate[b]	Fatalities
U.S. 40 west (Wasatch County to S.R. 208)	1.87	1.56	2.5	7.6	0
U.S. 40 central (S.R. 208 to Naples)	1.61	1.56	5.3	7.6	11
U.S. 40 east (Naples to Colorado)	1.03	1.56	7.0	7.6	2
U.S. 191 south (Carbon County to U.S. 40)	2.93	1.90	19.5	10.9	2
U.S. 191 north (U.S. 40 to Daggett County)	4.31	1.90	24.5	10.9	2
S.R. 35 (S.R. 208 to S.R. 87)	1.22	1.97	9.1	12.1	2
S.R. 45	4.20	1.97	0.0	12.1	0
S.R. 87	1.63	1.97	7.2	12.1	2
S.R. 88	1.17	1.97	4.7	12.1	0
S.R. 121	2.74	1.97	4.3	12.1	0
S.R. 208	2.63	1.97	26.3	12.1	1

Source: USTM

[a] Crashes per year per million-vehicle miles (2008–2010)

[b] 5-year (2006–2010) statewide average based on roadway functional class, AADT, and urban/rural area type

[c] Severe crashes (incapacitating injury or fatal crashes) per year per hundred million-vehicle-miles

Similar to the capacity analysis, the safety analysis presented in this appendix does not attempt to define a plan for the area or focus on areas of safety concern. The safety analysis simply offers the crash history in the area and helps to strengthen the link between travel demand, traffic capacity, and traffic safety. By normalizing the crash histories into crash rates, expectations of the future can be developed, assuming no major changes.

Appendix B: User Benefits and Environmental and Social Cost Analysis Data and Assumptions

This appendix provides a summary of the assumptions use in the benefit-cost analysis (BCA).

Table 86: Summary of Assumptions and Ranges

Variable	Median	Lower 10%	Upper 10%	Source and Notes
General Assumptions				
Discount rate, nominal	3%			Office of Management & Budget Circular A-94
Annualization factor	300			HDR Assumption
Passenger car equivalent for truck	2			HDR Assumption
Passenger car equivalent for combo truck	2.5			HDR Assumption
Value of Time				
Value of time	$13.90	$9.80	$16.70	Based on Median Household Income for Utah from the U.S. Census, and calculated using TIGER IV Methodology
Single truck	$47.94	$43.14	$52.73	Based on average hourly wage for Utah truck drivers from the Bureau of Labors Statistics, and calculated using HERS Methodology and RAP Workshop Feedback, November 30, 2012
Real growth rate – value of time	1.60%			TIGER IV Methodology
Average Trip Length				
East	25.2			Data from Uinta Basin USTM Summary by Route_Update_12062012.xls
West	9.5			Data from Uinta Basin USTM Summary by Route_Update_12062012.xls
North	25.7			Data from Uinta Basin USTM Summary by Route_Update_12062012.xls
South	34.8			Data from Uinta Basin USTM Summary by Route_Update_12062012.xls
Local	395.1			Data from Uinta Basin USTM Summary by Route_Update_12062012.xls
Vehicle Operating Costs				
Cost of fuel – autos, $/gal	$3.77			EIA
Cost of oil, $/quart	$9.52	$7.62	$11.42	Based on FHWA, Highway Economic Requirement System (HERS), inflated to 2012 dollars using series specific CPI (includes the labor charge for changing the oil).
Cost of tire, $/tire	$94.90	$75.92	$113.88	Based on FHWA, Highway Economic Requirement System (HERS), inflated to 2008 dollars using series specific CPI.

Table 86: Summary of Assumptions and Ranges

Variable	Median	Lower 10%	Upper 10%	Source and Notes
Cost of maintenance and repair – autos, $/Vehicle/1,000 mi	$164.40	$131.52	$197.28	Based on FHWA, Highway Economic Requirement System (HERS), inflated to 2012 dollars using series specific CPI.
Average depreciable value – autos	$21,487	$17,189	$25,784	Based on FHWA, Highway Economic Requirement System (HERS), inflated to 2012 dollars using series specific CPI.
Emissions				
VOC cost	$1,457	$1,165	$1,748	$/metric ton, values derived from TIGER IV Methodology
NO_x cost	$5,954	$4,764	$7,145	$/metric ton, values derived from TIGER IV Methodology
PM cost	$325,684	$260,547	$390,821	$/metric ton, values derived from TIGER IV Methodology
SO_2 cost	$34,811	$27,849	$41,774	$/metric ton, values derived from TIGER IV Methodology
C cost	$26	$6	$39	$/metric ton, values derived from TIGER IV Methodology
Accidents				
Cost of a fatal accident	$6,200,000	$3,410,000	$8,990,000	Values derived from TIGER IV Methodology
Cost of an injury accident	$77,476	$42,612	$112,340	Values derived from TIGER IV Methodology
Cost of a property damage only accident	$3,503	$2,802	$4,203	Values derived from TIGER IV Methodology

Note: Passenger car equivalent (PCE); Transportation Investment Generating Economic Recovery (TIGER); Highway Economic Requirement System (HERS); Risk Analysis Process (RAP); dollars per gallon ($/gal); dollars per quart ($/quart); dollars per tire ($/tire); consumer price index (CPI); volatile organic compound (VOC); nitrous oxides (NO_x); particulate matter (PM); sulfur dioxide (SO_2); carbon dioxide (Sulfur dioxide (SO_2); and dollars per metric ton ($/metric ton).

Table 87: Site Impact Assumptions

Commodity	Production of Greenhouse Gas Emissions (grams per barrel)	Water Use (gallons per barrel)	Cost of Ecosystem Goods and Services (m2/m3 SCO)[a]
Conventional gas (grams per cfe)	20.5	–	–
Conventional oil	29,000	–	0.11
Oil sands	30,000	102	0.28
Oil shale	460,432	–	–

Note: cubic foot of gas (cfe).

[a] This unit is a measure of land disturbance per energy output.

Sources Reviewed

Greenhouse gas emission rates were derived from:

- Congressional Research Service. 2012. Canadian Oil Sands: Life-Cycle Assessments of Greenhouse Gas Emissions report.

- Argonne National Laboratory and U.S. Department of Energy's Life-Cycle Greenhouse Gas Emissions of Shale Gas, Natural Gas, Coal, and Petroleum.

Water use values were derived from:

- Ceres Organization. 2010. Canada's Oil Sands: Shrinking Window of Opportunity report.

Impacts to natural resources and wildlife were derived from:

- Environmental Research Letter. 2009. Quantifying land use of oil sands production: a life cycle perspective.

Appendix C: Risk Analysis Process Summary

Economic forecasts traditionally take the form of a single expected outcome supplemented with alternative scenarios. The limitation of a forecast with a single expected outcome is clear—while it might provide the single best statistical estimate, it offers no information about the range of other possible outcomes and their associated probabilities. The problem becomes acute when uncertainty surrounding the forecast's underlying assumptions is material.

A common approach is to create "high case" and "low case" scenarios to bracket the central estimate. This approach can exacerbate the problem of dealing with risk because it gives no indication of the likelihood associated with the alternative outcomes. The commonly reported high case might assume that most underlying assumptions deviate in the same direction from their expected value, and likewise for the low case. In reality, the likelihood that all underlying factors shift in the same direction simultaneously is just as remote as that of everything turning out as expected.

Another common approach to providing added perspective on reality is sensitivity analysis. Key forecast assumptions are varied one at a time in order to assess their relative impact on the expected outcome. A problem here is that the assumptions are often varied by arbitrary amounts. A more serious concern with this approach is that, in the real world, assumptions do not veer from actual outcomes one at a time. It is the impact of simultaneous differences between assumptions and actual outcomes that is needed to provide a realistic perspective on the riskiness of a forecast.

Risk analysis provides a way around the problems described above. It helps avoid the lack of perspective in high and low cases by measuring the probability or "odds" that an outcome will actually materialize. This is accomplished by attaching ranges (probability distributions) to the forecasts of each input variable. The approach allows all inputs to be varied simultaneously within their distributions, thus avoiding the problems inherent in conventional sensitivity analysis. The approach also recognizes interrelationships between variables and their associated probability distributions.

The Risk Analysis Process (RAP) involves four steps:

Step 1: Define the structure and logic of the forecasting problem

Step 2: Assign central estimates and conduct a probability analysis

Step 3: Conduct an expert evaluation: the RAP session

Step 4: Issue a risk analysis

Step 1: Define the Structure and Logic of the Forecasting Problem

A structure and logic model depicts the methodology non-mathematically, indicating how all variables and assumptions combine to yield a forecast. Such models provide a clear and uncomplicated means of presenting the evaluation steps and procedures to outside experts, stakeholders, and others in an expert panel session. Figure 66 below provides a sample structure and logic model for a roadway and/or transit infrastructure investment.

Figure 66: Example of a Structure and Logic Model (*for Illustration Only*)

Step 2: Assign Central Estimates and Conduct a Probability Analysis

Each variable is assigned a central estimate and a range (a probability distribution) to represent the degree of uncertainty. Special data sheets are used to record input from panelists. Table 88 below provides an example of data sheets. The first column gives an initial median, while the second and third columns define an uncertainty range representing an 80% confidence interval. This is the range within which there exists an 80% probability of finding the actual outcome. The greater the uncertainty associated with a forecast variable, the wider the range.

Table 88: Data Sheet for Population Growth (*for Illustration Only*)

Years	Median	10% Lower Limit	10% Higher Limit
2013–2015	2.5	1.7	3.4
2016–2020	2.0	1.5	4.1
2021 and after	1.8	1.0	4.7

Probability ranges are established on the basis of both statistical analysis and subjective probability. Probability ranges need not be normal or symmetrical; that is, there is no need to assume the bell-shaped normal probability curve. The bell curve assumes an equal likelihood of being too low and being too high in forecasting a particular value. It might well be, for example, that if a projected growth rate deviates from expectations; circumstances are such that it is more likely to be higher than the median expected outcome than lower.

The computer program used in the RAP process transforms the ranges as depicted above into formal probability distributions (or probability density functions). This liberates the non-statistician from the need to appreciate the abstract statistical depiction of probability and thus enables stakeholders to understand and participate in the process, whether or not they possess statistical training.

From where do the central estimates and probability ranges for each assumption in the forecasting structure and logic framework come? There are two sources. The first is a historical analysis of statistical uncertainty in all variables and an error analysis of the forecasting coefficients. Coefficients are numbers that represent the measured impact of one variable (say, income) on another (such as retail sales). Although these coefficients can be known only with uncertainty, statistical methods help uncover the magnitude of such error (using diagnostic statistics such as standard deviation, standard error, confidence intervals, and so on).

The uncertainty analysis described above is known in the textbooks as frequentist probability. The second line of uncertainty analysis used in risk analysis is called subjective probability (also called Bayesian statistics, after the mathematician Bayes who developed it). Whereas a frequentist probability represents the measured frequency with which different outcomes occur (for example, the number of heads and tails after thousands of tosses), the Bayesian probability of an event occurring is the degree of belief held by an informed person or group that it will occur. Obtaining subjective probabilities is the subject of step 3.

Step 3: Conduct an Expert Evaluation: The RAP Session

Step 3 involves the formation of an expert panel and the use of facilitation techniques to elicit, from the panel, risk and probability beliefs about:

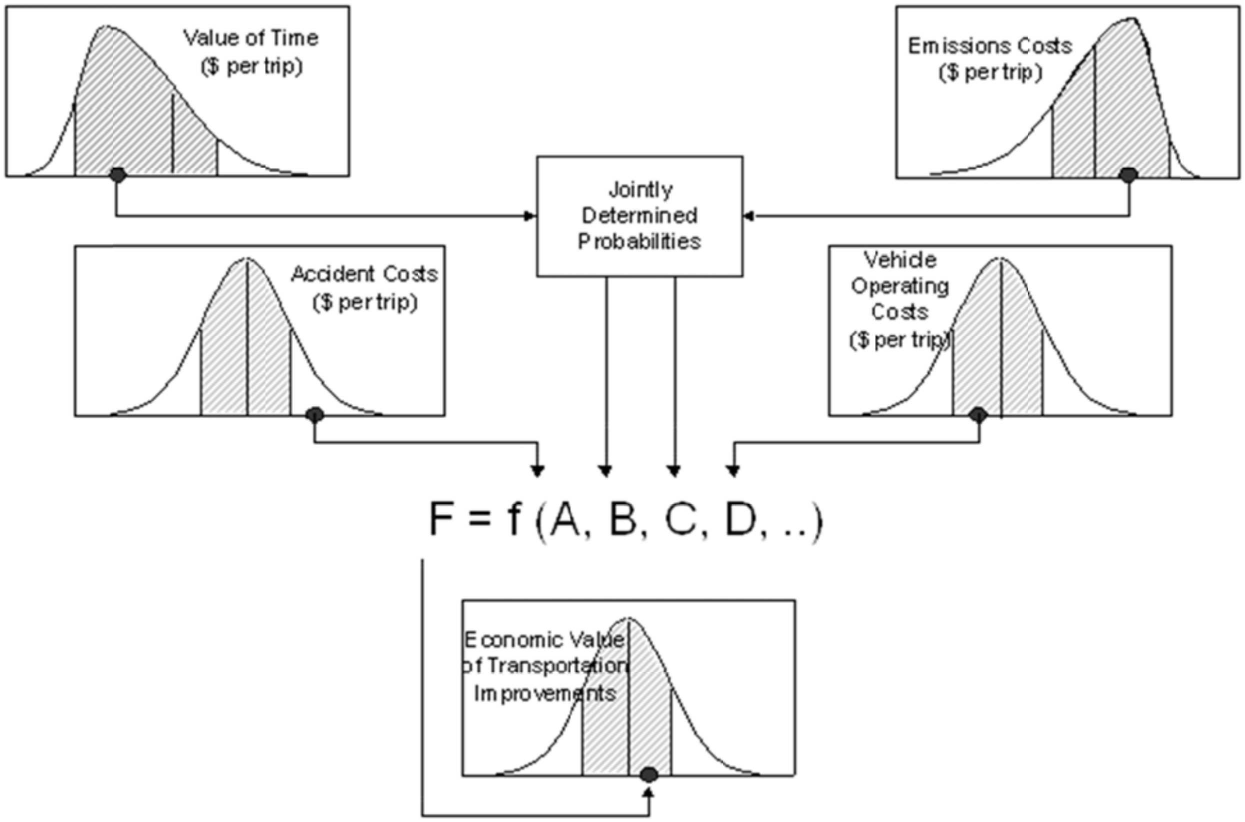
1. The structure of the forecasting framework; and
2. Uncertainty attaching to each variable and forecasting coefficient within the framework.

In part 1, experts are invited to add variables and hypothesized causal relationships that might be material, yet missing from the model. In part 2, panelists are engaged in a discursive protocol during which the frequentist-based central estimates and ranges, provided to panelists in advance of the session, are modified according to subjective expert beliefs. This process is aided with an interactive groupware computer tool that permits the visualization of probability ranges under alternative belief systems.

Step 4: Issue a Risk Analysis

The final probability distributions are formulated by the risk analyst (HDR Decision Economics) and represent a combination of frequentist and subjective probability information drawn from step 3. These are combined using a simulation technique (Monte Carlo analysis) that allows each variable and forecasting coefficient to vary simultaneously according to its associated probability distribution (Figure 67).

Figure 67: Combining Probability Distributions (*for Illustration Only*)



The end result is a central forecast, together with estimates of the probability of achieving alternative outcomes given uncertainties in underlying variables and coefficients (see Table 89 and Figure 68).

Table 89: Example of Risk Analysis Output (*for Illustration Only*)

Cost Savings from Transportation Improvements	
Cost Savings ($Million)	**Probability of Exceeding Value Shown at Left (%)**
$63.3	95%
$87.0	90%
$115.9	80%
$137.1	70%
$155.8	60%
$174.0	50%
$193.3	40%
$215.5	30%
$244.3	20%
$291.0	10%
$337.2	5%

Figure 68: Example of Risk Analysis Output, Decumulative Probability Distribution (*for Illustration Only*)